**CASE NO. 2022-00372**

## LIST OF EXHIBITS

TO THE DIRECT TESTIMONY OF SARAH SHENSTONE-HARRIS
ON BEHALF OF SIERRA CLUB

| Exhibit No. | Description of Exhibit | Protected Status |
|---|---|---|
| SSH-1 | Resume of Sarah Shenstone-Harris | Public |
| SSH-2 | Public Company Responses to Data Requests | Public |
| SSH-3 | Confidential Company Responses to Data Requests | Confidential |
| SSH-4 | Supporting Materials | Public |

**EXHIBIT SSH-1**

Resume of Sarah Shenstone-Harris

**Sarah Shenstone-Harris**, Senior Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-245-8222
sshenstone-harris@synapse-energy.com

## PROFESSIONAL EXPERIENCE

**Synapse Energy Economics Inc.**, Cambridge, MA. *Senior Associate*, October 2022 – Present.

- Provides research, analysis, and consulting services on various energy-sector issues, including integrated resource planning, rate design, electric vehicles and electrification, and clean energy
- Evaluates utility rate designs and their impacts on electric vehicles
- Forecasts load changes and their impacts on rates from future electric vehicle adoption
- Assesses the economic viability of generation resources (legacy coal plants, new solar projects) as opposed to alternative resources and market purchases

**Reading Municipal Light Department (RMLD),** Reading, MA. *Integrated Resource Analyst I,* January – September 2022; *Integrated Resource Specialist,* October 2020 – December 2021.

*Integrated Resource Analyst I:*

- Planned the Department's wholesale power supply strategy, including developing and running economic models to evaluate power supply decisions. Consistently working to achieve RMLD's goals of delivering reliable, low-cost, and emission-free power
- Led the rate increase process and the design of new rate structures, such as a residential electric vehicle time-of-use rate.
- Managed the retirement and sales of RMLD's Renewable Energy Certificates (RECs) and Emission-Free Certificates (EFECs) to ensure compliance with MA Climate Law and the achievement of RMLD's grid decarbonization goals, while keeping rates affordable for all classes
- Developed and maintained forecasting tools of retail load, energy purchases and hedging, power supply costs (energy, transmission, and capacity), and RECS/EFECs
- Prepared annual and monthly power supply budgets for energy, transmission, and capacity costs
- Adjusted monthly rates for all classes, based on expected costs and revenues
- Designed and implemented significant process improvements to track budgeted and actual costs, and manage the $65 million power supply budget

*Integrated Resource Specialist:*

- Administered, promoted, coordinated, and reported on utility energy efficiency and electrification programs, including Air Source Heat Pumps, Electric Vehicle Chargers, Commercial Lighting, Solar and Distributed Generation, Energy Audits, Appliance Rebates, and other energy management programs
- Designed and developed economic and analytical tools to help achieve RMLD's power supply and retail goals and objectives, such as a rate analysis models

- Developed and expanded utility load forecasts, to inform both power supply strategy and program management
- Implemented significant program process improvements, resulting in a >50% reduction in customer rebate application turnaround time
- Established systems to track program performance, including measure adoption, cost-effectiveness, energy savings, and environmental impacts
- Responsible for reporting to external agencies, such as the ISO-NE and US Energy Information Administration (EIA), as well as to board members and key stakeholders on all retail program activities
- Provided technical support to the Customer Service team, including administering training on new programs, a customer portal for rebate applications, and new program processes
- Coordinated with other RMLD departments, vendors, program partners, and other utilities to support RMLD programs and goals

**ICLEI Canada – Local Governments for Sustainability,** Toronto, Ontario, Canada. *Climate & Energy Planner Project Assistant*, October 2018 – March 2020; *Climate & Energy Project Assistant*, October 2017 – October 2018.

- Coordinated ICLEI's climate and energy consulting work for municipalities, including:
    - Stakeholder engagement (stakeholder identification, establishment of working groups, facilitating dialogue, collecting feedback and incorporating stakeholder input)
    - Identifying and developing programs and policies to improve environmental sustainability across multiple sectors (buildings, transportation, waste, land use, resource use, etc.)
    - Quantifying environmental and financial impacts of emission and energy reduction measures, identifying and collecting data sources, modelling energy and emissions with different policy options
    - Clearly and succinctly summarizing technical concepts to clients and stakeholders
    - Presenting recommendations and final plans to City Councils
- Coordinated and delivered capacity-building programs that support Canadian municipalities in greenhouse gas emissions mitigation activities and community energy planning
- Created resources and tools for climate action plan development and implementation (best practice guidelines, communication materials, emission measurement tools, decision-support tools, etc.)
- Developed and delivered workshops, webinars and training services to local governments participating in ICLEI programs and projects

**Sustainable Development Technology Canada,** Ottawa, Ontario, Canada. *Research and Technology Analyst* (8-month Co-op position), September 2016 – April 2017.

- Wrote and prepared briefing packages for the Board of Director's Investment Committee, detailing the technological, business, intellectual property, and financial merits of clean tech projects seeking funding

- Conducted research to assess and inform SDTC's clean tech investment priorities

## EDUCATION

**University of Ottawa**, Ontario, Canada
Master of Science in Environmental Sustainability (focus on policy and economics), Institute of the Environment, 2017.

**Queen's University**, Kingston, Ontario, Canada
Bachelor of Science in Biology, 2013.
Graduated with Distinction and Dean's List Honors

## PUBLICATIONS & TESTIMONY

**Public Service Commission of the State of Missouri (File No. EA 2022-0245):** Surrebuttal testimony of Sarah Shenstone-Harris regarding Ameren Missouri's Application for a Certificate of Convenience and Necessity of a Solar Facility. January 18, 2023.

ICLEI Canada and Wood PLC. 2021. *Town of Aurora (Ontario) Community Energy Plan.*

ICLEI Canada and Wood PLC. 2020. *Township of Huron-Kinloss (Ontario) Climate Change and Energy Plan*.

LURA Consulting and ICLEI Canada. 2019. *City of Kawartha Lakes (Ontario), Healthy Environment Plan*.

ICLEI Canada and the Federation of Canadian Municipalities. 2020. *Guidebook on Quantifying Greenhouse Gas Reductions at the Project Level.*

Shenstone-Harris, S., Cai, Y., and Dean, M. 2019. *On the Money: Financing Tools for Local Climate Action, 2019*. Prepared for Partners for Climate Protection.

ICLEI Canada and the Federation of Canadian Municipalities. 2018 and 2019. *Partners for Climate Protection National Measures Report 2018, Partners for Climate Protection National Measures Report 2019*.

Rivers, N., S. Shenstone-Harris, N. Young. 2017. *Using nudges to reduce waste? The case of Toronto's plastic bag levy*. Journal of Environmental Management, Volume 188. ISSN 0301-4797. ZURA Consulting.

*Resume updated February 2023*

**EXHIBIT SSH-2**

Public Company Responses to Data Requests

**Data Requests**

DEK Response to Sierra Club Request 1-7
DEK Response to Sierra Club Request 1-16
DEK Response to Sierra Club Request 1-19
DEK Response to Sierra Club Request 1-22
DEK Response to Sierra Club Request 1-23
DEK Response to Sierra Club Request 2-3

DEK Response to Kroger Request 1-5 Attachment

**VERIFICATION**

| | | |
|---|---|---|
| **STATE OF OHIO** | ) | |
| | ) | **SS:** |
| **COUNTY OF HAMILTON** | ) | |

The undersigned, Michael Geers, Manager Environmental Services, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

J. Michael Geers Affiant

Subscribed and sworn to before me by Michael Geers on this 24th day of January, 2023.

NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

**VERIFICATION**

STATE OF NORTH CAROLINA )
) SS:
COUNTY OF MECKLENBURG )

The undersigned, Scott Park, Managing Director IRP & Analytics, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief

Scott Park Affiant

Subscribed and sworn to before me by Scott Park on this 20 day of January, 2023.

PATRICIA C. ROSS
NOTARY PUBLIC
Mecklenburg County
North Carolina

NOTARY PUBLIC
Patricia C. Ross

My Commission Expires: 10-23-2024

**SIERRA-DR-01-007**

**REQUEST:**

Please provide unredacted, in native format with all formulae intact, all analyses or assessments that study the value of continued operation (e.g., all retirement studies, unit condition assessments, or deactivation assessments) conducted since 2015, for East Bend Generation Station, including, but not limited to, all studies, presentations, reports, or other assessments conducted to determine how to comply with any existing, impending, or potential environmental regulation.

**RESPONSE:**

Objection. This request is overbroad and unduly burdensome, seeks to elicit information that is irrelevant or beyond the scope of these proceedings, and outside of the test year. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, please see Duke Energy Kentucky's Integrated Resource Plan provided as SIERRA-DR-01-003 Confidential Attachment.

**PERSON RESPONSIBLE:** As to objections, Legal
As to response, Scott Park

**SIERRA-DR-01-016**
**(incorrectly labeled as 1.13)**

**REQUEST:**

Has Duke conducted any analysis of the potential costs and timing for such costs at East Bend to comply with EPA's proposed Good Neighbor Plan, 87 Fed. Reg. 20,036 (Apr. 6, 2022)? If so, please provide all documents reflecting such analyses. If not, why not?

**RESPONSE:**

Duke Energy Kentucky has reviewed the proposal which would result in a change to the number of ozone season NOx allowances allocated to East Bend Station starting with the effective date of the final rule. EPA proposed other potential changes to its trading rule as well. Based on the proposal and using its existing Selective Catalytic Reduction (SCR) NOx controls, East Bend should be able to comply with the final rule without addition upgrades.

**PERSON RESPONSIBLE:** J. Michael Geers

**SIERRA-DR-01-019**
**(incorrectly labeled as 1.16)**

**REQUEST:**

Does Duke have a forecast for NOx credit costs under CSAPR or EPA's proposed Good Neighbor Plan, 87 Fed. Reg. 20,036 (Apr. 6, 2022)? If yes, please provide all forecasts through 2030. If not, why?

**RESPONSE:**

Objection. To the extent this request is intended to be duplicative of SIERRA-DR-01-016 (incorrectly labeled as 1.13), it must be seen as intending to harass. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, refer to the response for SIERRA-DR-01-016. In addition, it is difficult to predict the future cost of ozone season NOx allowances because the market will react to a number of factors such as the exact date that the final rule becomes effective, the final scope of sources included in the relevant trading region, and any other changes EPA may make to the trading program.

**PERSON RESPONSIBLE:** As to objection, Legal
As to response, J. Michael Geers

**Duke Energy Kentucky**
**Case No. 2022-00372**
**SIERRA CLUB First Set Data Requests**
**Date Received: January 10, 2023**

**SIERRA-DR-01-022**
**(incorrectly labeled as 1.19)**

**REQUEST:**

Has Duke conducted any analysis of the compliance costs at East Bend to comply with EPA's Effluent Limitations Guidelines ("ELG Rule"), 40 C.F.R. Part 423, at East Bend?

a. If so, please provide all documents reflecting such analyses. If not, why not?

b. Identify the total cost of the projects the Company intends to undertake or has undertaken at East Bend to comply with the ELG Rule.

c. State the year these costs have been or will be incurred.

d. Please identify and describe each itemized capital expenditure required to complete the ELG Rule compliance project.

e. State whether any of those costs are included in Duke's test year, and if so, Identify the specific costs included.

f. Could any of those ELG Rule expenditures be avoided by making a commitment to cease burning coal under the ELG Rule's alternative closure provisions, 40 C.F.R. § 423.19(f)? If so, please identify each specific avoidable cost.

g. Please provide all evaluations of the technical or engineering compliance options for the ELG Rule for East Bend.

h. Produce all evaluation(s) that the Company performed to determine that incurring any avoidable ELG Rule costs at East Bend is in customers' best interest (i.e., present value of retrofit versus retirement analyses). For any such evaluation, provide the following data:

i. All workpapers, with formulas intact.

ii. Provide a list of all capital expenditures associated with ELG Rule compliance included in each modeled scenario and provide the cost of each.

iii. MISO Energy price forecasts (with and without CO2 price);

iv. MISO Capacity price forecasts (with and without CO2 price);

v. CO2 price forecasts

vi. Coal price ($/MMBtu)

vii. Gas price ($/MMBtu)

viii. Heat rate (Btu)

ix. Capital expenditures ($)

x. Variable Operation and Maintenance ($/MWh)

xi. Fixed Operation and Maintenance ($/MW)

xii. For each replacement resource available to the model, provide each of the following inputs for each resource at the highest level of granularity used in conducting the retrofit analysis:

  8. Replacement resource options

  9. Replacement resource size (MW)

  10. Year replacement resource is available (year)

  11. Cost of replacement resource option ($/MW)

  12. Annual capacity factor

  13. Year of transmission upgrade (if required)

14. Cost of transmission upgrade (if required)

**RESPONSE:**

Objection. This request is overbroad, unduly burdensome, seeks information that is irrelevant and not likely to lead to the discovery of admissible and relevant evidence. In addition the question is moot because the projects involved were previous approved and constructed. Without waiving said objection, and to the extent discoverable:

a. N/A. The East Bend Generating Station is fully compliant with the 2015 and 2020 Steam Electric ELG Rules.

b. The bottom ash submerged flight conveyor project was completed during 2018 and cost approximately $32.1 million.

c. The bottom ash submerged flight conveyor project was completed during 2018.

d. Bottom ash submerged flight conveyor = approximately $32.1 million.

e. Yes. These costs are included in base rates. Base rates in this proceeding would reflect a return on and of the remaining NBV of the project in the test period.

f. As the bottom ash submerged flight conveyor was installed prior to the 2020 ELG Rule "alternative closure provisions," this question is not applicable.

g. N/A.

h. N/A.

**PERSON RESPONSIBLE:** J. Michael Geers

**Duke Energy Kentucky**
**Case No. 2022-00372**
**SIERRA CLUB First Set Data Requests**
**Date Received: January 10, 2023**

**SIERRA-DR-01-023**
**(incorrectly labeled as 1.20)**

**REQUEST:**

Has Duke conducted any analyses or assessments evaluating the impacts of the Inflation Reduction Act on the continued operation, replacement, or retirement (e.g., all retirement studies, unit condition assessments, or deactivation assessments) of any of its fossil-fuel burning generation resources? If yes, please provide all analyses, unredacted and in native format with all formulae intact. If not, why hasn't Duke conducted such an analysis?

**RESPONSE:**

The Company has not performed any detailed analysis of the IRA impacts, as it relates to its Integrated Resource Planning beyond high level considerations of tax incentive and updating of fuel prices. Other factors, however, will impact the continued operation, replacement, or retirement of East Bend, including but not limited to cost of new resources and supply chain and inflationary pressures. All else being equal, the Company expects that the IRA will drive more renewable additions putting downward pressure on energy prices which would decrease the capacity factor of coal generation. However, for reliability purposes, coal units could be kept around for capacity resources rather than as energy producing resources as has been past practice. While some newer technologies are incentivized through the IRA, those incentivized resources will impact economics and may or may not accelerate coal retirement.

**PERSON RESPONSIBLE:** Scott Park

**SIERRA-DR-02-003**

**REQUEST:**

Please refer to Table H.2 in SIERRA-DR-01-003 CONF Attachment regarding East Bend's projected cost and operating information from 2021-2035.

a. Clarify what is included in the line item "Fixed O&M + Maintenance Capital". Confirm that it includes both Fixed O&M that is included in rates and sustaining capital costs that are included in rate base.

b. Please explain how sustaining capital costs are incorporated into resource planning modeling.

c. If sustaining capital expenditures are not included in Table H.2, please provide a forecast of sustaining capital expenditures for all available years.

**RESPONSE:**

a. Yes, the line item "Fixed O&M + Maintenance Capital" includes Fixed O&M and the sustaining capital costs are included in the IRP modeling. The data included in Table H.2 of the IRP as attached in SIERRA-DR-01-003 Confidential Attachment is forecasted data for 2021 – 2035 for purposes of the IRP. It is not meant to reflect what is in the test period in this proceeding.

b. Assuming that "sustaining capital" is intended to mean the same thing as "maintenance capital", those costs are included in the analysis.

c. Please see response (b)

**PERSON RESPONSIBLE:** Scott Park

## VERIFICATION

**STATE OF NORTH CAROLINA** )
) **SS:**
**COUNTY OF MECKLENBURG** )

The undersigned, Huyen C. Dang, Director of Accounting, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Huyen C. Dang Affiant

Subscribed and sworn to before me by Huyen C. Dang on this 19 day of 2023, 2023.

VIRGINIA M. ADAMS
My Comm. Expires
NOTARY PUBLIC
October 2, 2026
MECKLENBURG COUNTY, NC

Virginia M. Adams
NOTARY PUBLIC

My Commission Expires: 10/2/26

**KROGER-DR-01-005**

**REQUEST:**

Refer to the direct testimony of Sarah E. Lawler, pp. 5-6. *"East Bend is now currently projected to retire in 2035, six years earlier than its originally planned retirement date of 2041. In order to align the depreciation rates with this new estimated retirement date, depreciation expense has to increase. This is driving approximately $11 million of the total $35 million increase in depreciation expense. Partially mitigating this increase is the fact that the estimated retirement date of Woodsdale is now projected to be 2040, eight years later than its originally planned retirement date. Included in the $35 million increase in depreciation expense is an approximately $7 million decrease associated with this extension of useful life."*

a. Please provide all workpapers in Excel format documenting the change in depreciation expense that would result from the Company's filed case.

**RESPONSE:**

Please see KROGER-DR-01-005 Attachment which contains depreciation calculations for East Bend (Steam Production accounts) and Woodsdale (Other Production accounts) which sets forth the result of changing the proposed retirement dates from the Depreciation Study (2035 for East Bend and 2040 for Woodsdale) with the previous retirement dates (2041 and 2032, respectively). These new calculations compared to the Depreciation Study result in a decrease of annual depreciation expense for East Bend and an increase for Woodsdale.

It should be noted that changing the retirement dates can create changes in weighted net salvage, distribution of the book reserve, and forecasted interim and terminal retirements. The comparison provided in this response reflects changes to some of these factors.

**PERSON RESPONSIBLE:** John J. Spanos

**DUKE ENERGY KENTUCKY**

**SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2021**

| | ACCOUNT | PROBABLE RETIREMENT DATE | SURVIVOR CURVE | NET SALVAGE PERCENT | ORIGINAL COST AS OF DECEMBER 31, 2021 | BOOK DEPRECIATION RESERVE | FUTURE ACCRUALS | CALCULATED ANNUAL ACCRUAL AMOUNT | CALCULATED ANNUAL ACCRUAL RATE | COMPOSITE REMAINING LIFE |
|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9)=(8)/(5) | (10)=(7)/(8) |
| | **STEAM PRODUCTION PLANT** | | | | | | | | | |
| 3110 | STRUCTURES AND IMPROVEMENTS | 06-2041 | 85-S1 * | (12) | 183,717,638.42 | 46,934,083 | 158,829,672 | 8,244,218 | 4.49 | 19.3 |
| 3120 | BOILER PLANT EQUIPMENT | 06-2041 | 45-S0.5 * | (12) | 545,368,156.24 | 298,832,215 | 311,980,120 | 17,461,319 | 3.20 | 17.9 |
| 3123 | BOILER PLANT EQUIPMENT - SCR CATALYST | 06-2041 | 10-S2.5 * | 0 | 7,984,157.58 | 5,266,747 | 2,717,411 | 471,763 | 5.91 | 5.8 |
| 3140 | TURBOGENERATOR UNITS | 06-2041 | 40-S0.5 * | (12) | 109,285,792.05 | 59,323,750 | 63,076,337 | 3,736,806 | 3.42 | 16.9 |
| 3150 | ACCESSORY ELECTRIC EQUIPMENT | 06-2041 | 65-R2.5 * | (12) | 48,173,349.90 | 33,908,388 | 20,045,764 | 1,058,205 | 2.20 | 18.9 |
| 3160 | MISCELLANEOUS POWER PLANT EQUIPMENT | 06-2041 | 55-S0 * | (12) | 23,997,105.75 | 11,357,282 | 15,519,476 | 859,968 | 3.58 | 18.0 |
| | **TOTAL STEAM PRODUCTION PLANT** | | | | **918,526,199.94** | **455,622,465** | **572,168,780** | **31,832,279** | | |
| | **OTHER PRODUCTION PLANT** | | | | | | | | | |
| 3410 | STRUCTURES AND IMPROVEMENTS | 06-2032 | 60-R4 * | (5) | 36,379,260.23 | 27,885,105 | 10,313,118 | 1,000,447 | 2.75 | 10.3 |
| 3420 | FUEL HOLDERS, PRODUCERS AND ACCESSORIES | 06-2032 | 45-S1.5 * | (5) | 61,310,889.91 | 6,744,645 | 57,631,789 | 5,577,093 | 9.10 | 10.3 |
| 3430 | PRIME MOVERS | 06-2032 | 25-S0 * | (5) | 10,340,709.70 | 1,522,502 | 9,335,243 | 973,278 | 9.41 | 9.6 |
| 3440 | GENERATORS | 06-2032 | 40-S0.5 * | (5) | 211,248,425.04 | 137,426,306 | 87,384,540 | 8,903,824 | 4.21 | 9.5 |
| 3450 | ACCESSORY ELECTRIC EQUIPMENT | 06-2032 | 35-S1 * | (5) | 19,858,901.69 | 12,312,595 | 8,539,252 | 928,405 | 4.68 | 9.2 |
| 3460 | MISCELLANEOUS POWER PLANT EQUIPMENT | 06-2032 | 45-R1.5 * | (5) | 5,152,109.78 | 3,329,034 | 2,080,681 | 209,824 | 4.07 | 9.9 |
| | **TOTAL OTHER PRODUCTION PLANT** | | | | **344,290,296.35** | **189,220,187** | **175,284,623** | **17,592,871** | | |

* CURVE SHOWN IS INTERIM SURVIVOR CURVE. EACH FACILITY IN THE ACCOUNT IS ASSIGNED AN INDIVIDUAL PROBABLE RETIREMENT YEAR.

**EXHIBIT SSH-4**

Supporting Materials

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PJM Cone 2026/2027 Report (April 2022)

PJM 2024/2025 Base Residual Auction Report (February 28, 2023)

U.S. Energy Information Administration, Generating Unit Annual Capital and Life Extension Costs Analysis (December 2019)

PJM Planning Division, Grid of the Future: PJM's Regional Planning Perspective (May 10, 2022)

Kuykendall, T., "Rail service 'meltdown' constraining US coal sector in hot market," S&P Global Market Intelligence (May 9, 2022)

Bittle, J., "Railroad strike threatens power in coal-dependent states," Grist, (September 14, 2022)

National Weather Service, "Low River Stages along the Lower Ohio and Mississippi Rivers."

Schneider, K., "CenterPoint Energy request 3-month rate hike for 2023 following coal plant failure," Indianapolis Star, (November 25, 2022)

Solomon, M., "Inflation Reduction Act Benefits: Billions In Just Transition Funding For Coal Communities," (August 24, 2022)

Varadarajan, U., Posner, D., Fisher, J., "Harnessing Financial Tools to Transform the Electric Sector." Sierra Club (November 2018)

2020 North Carolina Energy Regulatory Process, "Securitization for Generation Asset Retirement: Study Group Work Products," (December 18, 2020)

PREPARED BY

PREPARED FOR

APRIL 21, 2022


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Sang H. Gang
Patrick S. Daou
Joshua C. Junge
**Sargent & Lundy**


DATE

## NOTICE

This report was prepared for PJM Interconnection, 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.

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# Executive Summary

PJM Interconnection, L.L.C (PJM) retained consultants at The Brattle Group (Brattle) and Sargent & Lundy (S&L) to review key elements of the Reliability Pricing Model (RPM), as required periodically under PJM's tariff. This report presents our estimates of the Cost of New Entry (CONE) for the 2026/2027 commitment period, recommendations regarding the methodology for calculating the net energy and ancillary service revenue offset (E&AS Offset), and our recommendation for the selection of the reference resource. A separate, concurrently-released report presents our review of the VRR curve shape.

**Background**

The Variable Resource Requirement (VRR) curves set the price at the target reserve margin at approximately Net Cost of New Entry (Net CONE), such that the resource adequacy requirement will be achieved if suppliers enter the market when prices are at least Net CONE. In a downward-sloping curve, slightly lower reliability will be tolerated only when prices exceed Net CONE and some incremental capacity will be procured when the incremental cost is relatively low.

Net CONE is estimated by selecting an appropriate reference resource that economically enters the PJM market, determining its characteristics and its capital costs and ongoing operating and maintenance costs; then estimating a first-year capacity payment needed for entry, given likely trajectories of future total revenues and E&AS offsets.

A common misconception is that by selecting a reference resource, PJM promotes the development of that specific type of resource. In fact, other technologies may enter alongside the reference resource or instead of the reference resource, depending on which resources are most competitive and/or enjoy policy support. Another common misconception is that the Net CONE parameter sets capacity prices. In fact, capacity prices are determined by the intersection of the VRR curves and the supply curves. Long-run market clearing prices depend on the actual prices at which new competitive supply is willing to enter rather than the administrative Net CONE estimates, while the VRR curve determines only the quantity of capacity procured (short-term price impacts of changes in administrative Net CONE may be larger, depending on the elasticity of supply).

**Reference Resource**

The reference resource should be feasible to build within the three-year period between the Base Residual Auction and the delivery year; economically viable, as indicated by actual merchant entry and competitive costs; and amenable to accurate estimation of its Net CONE.

We recommend shifting the reference resource from the current natural gas-fired combustion turbine (CT) to a natural gas-fired combined cycle (CC) because the CC best meets these criteria in PJM. The CC is clearly economically viable, as it has the largest amount of recent merchant entry and a lower estimated Net CONE than the other candidate resources. CTs continue to be less economic than CCs, consistent with their extremely limited entry in the recent past. Selecting the CT as the reference resource would set the demand curve in a way that would perpetuate excess supply in PJM (although could be considered a way to buy extra reliability insurance for a premium). We considered BESS as a potential source of "clean capacity" for areas with more stringent environmental regulations that could limit the feasibility of developing new natural gas-fired resources. However, its estimated Net CONE is much higher than the CC without there being a clear enough indication at this time that the CC could not be built. We recommend that PJM, its stakeholders, and the states within the PJM footprint continue to monitor the viability of building new gas-fired resources and, if needed, consider developing a clean reference resource cost estimate.

For each resource evaluated, we developed technical specifications of a complete plant reflecting the locations, technology choices, and plant configurations that developers are likely to choose, as indicated by actual projects and current environmental requirements. The CC specifications are for a 1,182 MW plant with two trains of a single-shift combined cycle plant, each with a single combustion turbine, heat recovery steam generator, and steam turbine (i.e., two "single-shaft 1x1"s) including 123.9 MW of duct-firing capacity. The CC plant includes GE 7HA.02 turbines, selective catalytic reduction (SCR), dry cooling, and a firm gas transportation contract instead of dual-fuel capability.[1] The CC has a higher-heating value (HHV) average heat rate of 6,293 Btu/kWh at full load without duct firing and 6,537 Btu/kWh with (and 7,866 Btu/kWh at minimum stable level of 33% of full load) at standard conditions. CT specifications included a single simple cycle GE 7HA.02 with 367 MW capacity and a 9,189 Btu/kWh full-load average heat rate. BESS specifications are for a 200 MW 4-hour battery with 13% initial oversizing and capacity augmentation planned every 5 years to maintain charge capability and duration.

[1] These capacities and heat rates refer to an average over the four CONE Areas. Area-specific values reflecting local ambient conditions are provided within the report.

**Cost Analysis**

For CC and CTs in each CONE Area, we conducted a comprehensive, bottom-up analysis of the capital costs to build the plant: the engineering, procurement, and construction (EPC) costs, including equipment, materials, labor, and EPC contracting; and non-EPC owner's costs, including project development, financing fees, gas and electric interconnection costs, and inventories. We separately estimate annual fixed operation and maintenance (O&M) costs, including labor, materials, property taxes, and insurance. For BESS, we performed a top-down cost analysis based on a less detailed plant design and recent experience estimating costs for developers.

We translate the estimated costs into the net revenues the resource owner would have to earn in its first year to enter the market, assuming a 20-year economic life for the CC and CT and net revenues on average remain constant in nominal terms over that timeframe. We believe these assumptions are reasonable given widespread concern expressed by developers in the stakeholder community that gas-fired generation has limited value beyond the assumed 20-year life in a policy environment that increasingly disfavors greenhouse gas-emitting generation (and even capacity). For the BESS, we assumed a shorter 15-year economic life based on a representative degradation profile and warranty term typical for the selected battery technology.

To estimate the net revenue the reference resource would need to earn to achieve the required return on and return of capital, we estimated the cost of capital. We estimate an after-tax weighted-average cost of capital (ATWACC) of 8.0% for a merchant generation investment, based on analysis of publicly-traded merchant generation companies and other reference points. An ATWACC of 8.0% is equivalent to a return on equity of 13.6%, a 4.7% cost of debt, and a 55/45 debt-to-equity capital structure with an effective combined state and federal tax rate of 27.7%.

Table ES-1 below shows the resulting 2026/27 CONE estimates for CCs for each CONE Area. The CONE values are 56% higher (or $180/MW-day ICAP) than PJM's 2022/23 values from the 2018 CONE Study, averaged across all four CONE Areas. Three factors explain this increase:[2]

- Declining Bonus Depreciation**:** Bonus depreciation decreased from 100% to 20% under U.S. tax law, adding $25/MW-Day (ICAP) to CONE.
- Cost Escalation: The costs of materials, equipment, and labor have escalated and will continue to escalate at a faster rate than expected at the time of the last study. These cost increases add $92/MW-Day (ICAP) to CONE, relative to the 2022/23 estimate.

[2] These factors add to more than $180/MW-day (ICAP) due to offsets from a slightly lower cost of capital that reduces CONE by $4/MW-day (ICAP).

- Plant Design Changes: The use of dry-cooling, building a gas-only plant (without dual fuel capability) with firm gas transportation contracts under more constrained environmental permitting regimes (along with smaller increases from 2x1 to double-train 1x1 CCs) adds $66/MW-Day (ICAP).

**TABLE ES-1: ESTIMATED CONE FOR CC PLANTS**

| | | | | 1 x 1 Combined Cycle | | | |
|---|---|---|---|---|---|---|---|
| | | | | EMAAC | SWMAAC | Rest of RTO | WMAAC |
| | **Gross Costs** | | | | | | |
| [1] | Overnight | *$m* | | $1,359 | $1,240 | $1,263 | $1,308 |
| [2] | Installed (inc. IDC) | *$m* | | $1,470 | $1,343 | $1,367 | $1,415 |
| [3] | First Year FOM | *$m/yr* | | $37 | $53 | $47 | $39 |
| [4] | **Net Summer ICAP** | ***MW*** | | **1,171** | **1,174** | **1,144** | **1,133** |
| | **Unitized Costs** | | | | | | |
| [5] | Overnight | *$/kW* | = [1] / [4] | $1,160 | $1,057 | $1,104 | $1,154 |
| [6] | Installed (inc. IDC) | *$/kW* | = [2] / [4] | $1,255 | $1,144 | $1,195 | $1,248 |
| [7] | Levelized FOM | *$/kW-yr* | | $39 | $49 | $47 | $42 |
| [8] | **After-Tax WACC** | ***%*** | | **7.9%** | **8.0%** | **8.0%** | **8.0%** |
| [9] | Effective Charge Rate | *%* | | 12.4% | 12.2% | 12.3% | 12.3% |
| [10] | **Levelized CONE** | ***$/MW-yr*** | = [5] x [9] + [7] | **$182,700** | **$178,700** | **$183,100** | **$184,500** |
| [11] | **Levelized CONE** | ***$/MW-day*** | = [10] / 365 | **$501** | **$490** | **$502** | **$506** |

There is considerable uncertainty in the development of the estimated CONE values for the reference resources, particularly regarding volatile inflation, relevant technologies and plant designs, and the analyst’s judgment on economic life and long-term cost recovery. For example, a less constrained plant design with dual fuel and cooling towers could cost as much as $87/MW-day less; or a shorter 15-year economic life could add $52/MW-day, and the costs could be greater still if technologies are more constrained by environmental regulations. For BESS, the uncertainty in levelized costs is even greater because of rapidly-changing cost of equipment, currently unresolved applicability of tax credits, and other complications if combined into hybrid plants (and even greater uncertainty with E&AS offsets).

### E&AS Methodology

We continue to recommend using a forward-looking E&AS offset, as described in our 2020 testimony and as PJM implemented for its 2022/2023 capacity auction. This approach reflects future market conditions that developers face and avoids distortions from anomalous conditions in a backward-looking approach. We recommend continuing to use the same liquid hubs for natural gas and electricity, and scaling ancillary services prices to energy prices. We recommend that PJM should not include regulation revenues in its estimation of the E&AS offset since the market for regulation is too small to provide substantial additional revenue to capacity entering the PJM market at scale. These recommendations all apply equally to the CT, along with a recommended 10% increase in the estimated day-ahead gas costs to account for having to buy gas in the less liquid intraday market when committed in the real-time market. For BESS, we recommend using the same forward prices along with a virtual dispatch as PJM has been performing with the PLEXOS model.

Application of this forward methodology to CCs leads to indicative E&AS offset values for the CC of $209/MW-day for the RTO, $222 for MAAC, $189 for EMAAC, and $249 for SWMAAC (all denominated in 2026 dollars per UCAP MW-day). This is about $10-30/MW-day greater than the values used for MOPR reviews for the 2022/23 auction, with inflation more than offsetting other factors that tend to decrease the E&AS offset.

**Implications for Net CONE and VRR Curve**

*Elevated Net CONE*. With substantially higher CONE and only slightly higher indicative E&AS offsets, indicative CC Net CONE is correspondingly higher, at $307/MW-day for the RTO, $294 for MAAC, $329 for EMAAC, and $257 for SWMAAC (all denominated in 2026 dollars and UCAP MW). This is about $154 higher than CC Net CONE for 2022/23; it is similarly above recent capacity market clearing prices when new CCs entered, and this is consistent with cost escalation, more constrained plant designs, and tax laws; plus likely increased reluctance to invest given a regulatory and market environment that is increasingly favoring clean energy.

*Slightly elevated VRR Curve*. In spite of significant cost increases, updated CC Net CONE is only $47/MW-day higher than CT Net CONE for 2022/23, since CCs are more economic than CTs. Inefficiently maintaining the CT as the reference resource would increase Net CONE by much more. Thus, switching the reference resource to CCs would moderate the increase and should support procuring reserves closer to target.

*Heightened Uncertainty*. For the VRR curve to achieve resource adequacy objectives without procuring much below or above the target reserve margin, estimated Net CONE must accurately reflect the capacity price at which new capacity would enter. Yet uncertainty is endemic, particularly for an industry transitioning to new cleaner technologies with declining costs. Our indicative uncertainty analysis based on alternative assumptions noted above indicates a range of -29% to +16%; the uncertainty range may be greater when considering uncertainties beyond those we analyzed.  In that context, the VRR curve must be steeper to perform well even if Net CONE is mis-estimated, and we tested robustness under stress tests of +/-40%, as discussed in our parallel VRR Curve report.

# I. Introduction

## I.A. Background

PJM's capacity market, the Reliability Pricing Model (RPM), features a three-year forward auction and subsequent incremental auctions in which the Variable Resource Requirement (VRR) curve sets the "demand" for capacity. The VRR curve is designed primarily to procure sufficient capacity for maintaining resource adequacy according to traditional standards. The longstanding resource adequacy objectives are to avoid supply shortages in expectations all but once in ten years system-wide (i.e., Loss of Load Expectation or LOLE of 0.1 events/yr), with no more than 0.04 LOLE incremental risk in the Locational Deliverability Areas (LDAs). With probabilistic modeling conducted by PJM, these objectives are translated into Reliability Requirements expressed in terms of megawatts of unforced capacity (MW UCAP).

The VRR curves are centered approximately on a target point corresponding to the Reliability Requirements, at a price given by the estimated long-run marginal cost of capacity, termed the "Net Cost of New Entry (Net CONE)." Rather than a vertical line, the VRR is a curve with nonzero demand above the target to recognize the value of incremental capacity, and with a slope to help mitigate price volatility (as addressed in a separate VRR Curve Study report we are publishing concurrently with this report).

For the VRR curve to procure sufficient capacity, the Net CONE parameter must accurately reflect the price at which developers would be willing to enter the market if needed. Estimated Net CONE should reflect the first-year capacity revenue an economically-efficient new generation resource would require (in combination with its expected net revenues from the energy and ancillary services markets) to recover its capital and fixed costs, given reasonable expectations about future cost recovery. Thus, Net CONE is given by gross CONE minus the projected Energy and Ancillary Services revenue (E&AS Offset).

Following its tariff, PJM has traditionally estimated Net CONE for a new gas-fired combustion turbine (CT) entering in each of four CONE Areas.[3] Gross CONE values have been determined through quadrennial CONE studies such as this one, with escalation rates applied in the intervening years.[4] Shortly before each Base Residual Auction, PJM estimates an E&AS Offset for each zone, then calculates a relevant Net CONE value to use in each locational VRR curve being represented in the auction.

PJM also develops Net CONE estimates for a variety of technologies in order to develop offer price screens under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[5] This has less relevance than in past since PJM filed and FERC accepted a revision to MOPR rules that limit its applicability.

## I.B. Study Objective and Scope

PJM retained consultants at The Brattle Group and Sargent & Lundy to assist PJM and stakeholders in its quadrennial review. Per the PJM tariff, the scope of the Quadrennial Review is to review the VRR curve and its parameters, including the Cost of New Entry and the E&AS Offset methodology. To that end, a separate, concurrently issued report addresses the shape of the VRR curve. This report:

- Develops CONE estimates for new CT and CC plants and one "clean technology" in each of the four CONE Areas for the 2026/27 Base Residual Auction (BRA) and proposes a process to update these estimates for the following three BRAs;
- Reviews the E&AS offset methodology
- Recommends the most appropriate reference resource whose cost will best indicate the price at which developers would be willing to add capacity.

To estimate CONE for each resource type, we aim to represent the plant configuration, location, and costs that a competitive developer of new generation facilities will be able to achieve at generic sites, not unique sites with unusual characteristics. We estimate costs by specifying the

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3 The four CONE Areas are: CONE Area 1 (EMAAC), CONE Area 2 (SWMAAC), CONE Area 3 (Rest of RTO), and CONE Area 4 (WMAAC). PJM reduced the CONE Areas from five to four following the 2014 triennial review and incorporated Dominion (formerly CONE Area 5) into the Rest of RTO region.

4 PJM 2017 OATT, Section 5.10 a.

5 PJM 2017 OATT, Section 5.14 h.

reference resource and site characteristics, conducting a bottom-up analysis of costs, and translating the costs to a first-year CONE.

We provide relevant research and empirical analysis to inform our recommendations, but recognize where judgments have to be made in specifying the reference resource characteristics and translating its estimated costs into levelized revenue requirements. In such cases, we discuss the trade-offs and provide our own recommendations for best meeting RPM's objectives to inform PJM's decisions in setting future VRR curves. We provide not only our best estimate of CONE, but also inform the range of uncertainty, a key consideration in designing the VRR curve, as discussed in our separate report.

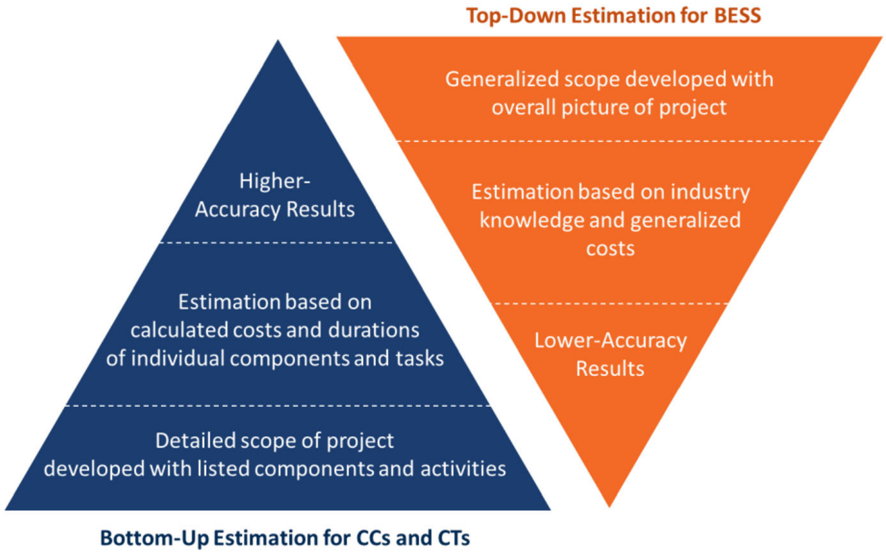
## I.C. Analytical Approach

Our starting point is to identify the most appropriate technology to serve as the reference resource for the VRR curve. As discussed in Section II, we identified criteria for selecting the reference resource then evaluated a broad range of resource types against those criteria in an initial screening analysis. This narrowed the choices to a CC, a CT, and BESS, for each of which we analyzed the costs more extensively further—and ultimately recommended using the CC as the reference resource for all locations.

For each of the three identified resources, we estimated CONE for the four CONE Areas, starting with a characterization of plant configurations, detailed specifications, and locations where developers are most likely to build. We identified specific plant characteristics and site characteristics based on: (1) our analysis of the predominant practices of recently developed plants; (2) our analysis of technologies, regulations, and infrastructure; and (3) our experience from previous CONE analyses. Our analysis for selecting plant characteristics for each CONE Area is presented in Section 0 of this report.

We developed comprehensive, bottom-up cost estimates of building and maintaining the reference CC and CT in each of the four CONE Areas. To present a reasonable order-of-magnitude cost estimate for the BESS, we utilized a generalized, top-down approach. Figure 1 describes the attributes of each approach.

FIGURE 1: ATTRIBUTES FOR BOTTOM-UP AND TOP-DOWN ESTIMATION METHODS




Sargent & Lundy (S&L) estimated plant proper capital costs—equipment, materials, labor, and the engineering, procurement, and construction (EPC) contracting costs—based on a complete plant design and S&L's proprietary database on actual projects. S&L and Brattle then estimated the owner's capital costs, including owner-furnished equipment, gas and electric interconnection, development and startup costs, land, inventories, and financing fees using S&L's proprietary data and additional analysis of each component. We further estimated annual fixed and variable O&M costs, including labor, materials, property tax, insurance, asset management costs, and working capital.

Next, we translated the total up-front capital costs and other fixed-cost recovery of the plant into an annualized estimate of fixed plant costs, which is the Cost of New Entry, or CONE. CONE depends on the estimated capital investment and fixed going-forward costs of the plant as well as the estimated financing costs (cost of capital, consistent with the project's risk) and the assumed economic life of the asset. The annual CONE value for the first delivery year depends on developers' long-term market view and how this long-term market view impacts the expected cost recovery path for the plant—specifically whether a plant built today can be expected to earn as much in later years as in earlier years.

The Brattle and S&L authors collaborated on this study and report. The specification of plant characteristics was jointly developed by both teams, with S&L taking primary responsibility for developing the plant proper capital, plant O&M and major maintenance costs, and the Brattle authors taking responsibility for various owner's costs and fixed O&M costs, and for translating the cost estimates into the CONE values.

# II. Reference Resource Selection

The purpose of selecting a reference resource and developing administrative Net CONE estimates is only to set a VRR curve that aims to procure enough resource adequacy credits. The choice of reference resource does not dictate which resources will enter the market. The administrative Net CONE value does not determine capacity prices; long-run prices depend primarily on the supply curve. Still, as the VRR curve is likely to remain sloped and anchored on our estimate of Net CONE, we aim to estimate Net CONE as accurately as possible, and that starts with a choice of the reference resource.

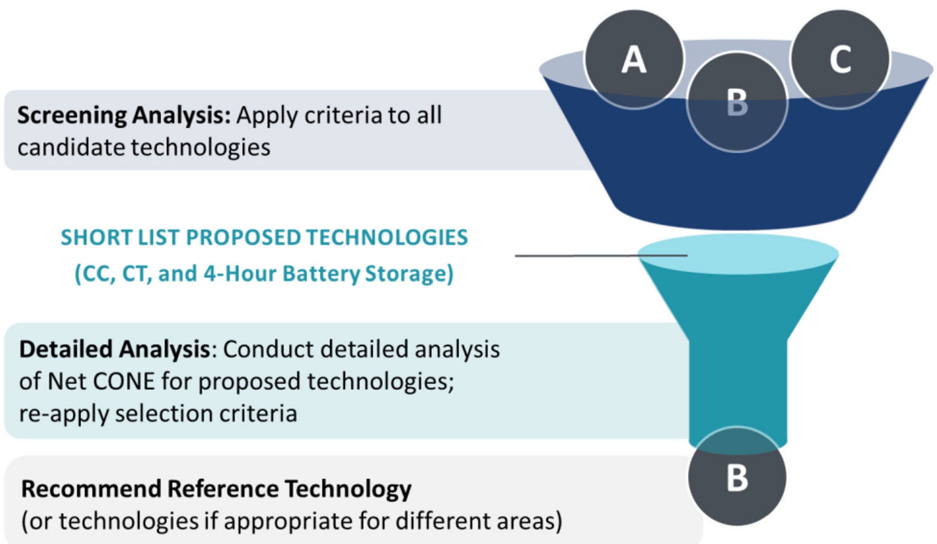
PJM has always used a reference resource, specifically a CT, to estimate Net CONE but asked us to evaluate its continued suitability for representing the cost at which suppliers are willing to bring significant amounts of capacity to PJM. We also considered CCs and a range of other technologies, including BESS as a possible "clean technology" for areas with more stringent environmental regulations. Finally, we also considered the possibility of relying on "empirical Net CONE," i.e. the price at which suppliers have willingly offered new capacity into recent auctions, rather than identifying a specific technology and estimating its net cost for future entry into the market. All possibilities were evaluated against a set of criteria for meeting RPM objectives.

In order to meet RPM reliability objectives with least risk of procuring far above or below target, we recommend switching to a CC as the reference resource. This aligns the VRR curve with observed entry of a technology that is feasible and most economic to build on a merchant basis, and whose Net CONE can be estimated relatively accurately. By contrast, CTs are not being built and are estimated to cost 20% more, on net, for capacity. Other technologies are similarly less economic or otherwise did not meet our selection criteria. Even in areas with more stringent environmental regulations, we did not identify a clear need to adopt a non-emitting reference resource at this time. Finally, empirical Net CONE is a useful benchmark but is not directly suitable because it does not reflect current market conditions affecting the costs of materials, equipment, and labor, nor the regulatory outlook that affects the design of the resources and their future revenue recovery.

## II.A. Process for Selecting Reference Resource

We conducted the analysis in several steps, as shown in Figure 2 below. First, we developed criteria for choosing a reference resource; second, we identified a broad range of technologies to evaluate at a high-level against those criteria, resulting in a short list for detailed cost and E&AS analysis; finally, we applied the selection criteria again to select the single most appropriate technology to serve as the reference resource, reflecting the updated net costs of those resources.

FIGURE 2: REFERENCE RESOURCE SELECTION PROCESS




In consultation with PJM and its stakeholders, we developed the reference resource selection criteria. The foundational objective of the selection criteria was to identify the resource that best supports the RPM's broader objective of procuring enough capacity to meet resource adequacy goals. Given that, we developed three selection criteria.

The first and most basic of these criteria is that the resource has to be feasible to build in the (slightly more than) three-year timeframe between the Base Residual Auction and the Delivery Year, so that high clearing prices in an auction can draw in potential projects when needed/economic.

The second criterion is that the resource must be an economic source of incremental capacity. Otherwise, anchoring the VRR curve on uneconomic sources of capacity would unnecessarily shift the VRR curve upward (like a shift outward) and procure more capacity than needed, at the quantity where the true Net CONE of economic resources intersects the VRR curve. Resources that are economic should exhibit actual merchant development and lower estimated Net CONE, and they should not be subject to factors that will likely render them uneconomic over the next several auctions governed by this Quadrennial Review. The reason for focusing on merchant entrants is partly to ensure that the VRR curve is set high enough to attract merchant entry in the future. It is also to avoid including policy-supported payments (such as renewable energy credits, or RECs) in the E&AS Offset, since such payments are difficult to assess absent broad competitive markets and are limited to the amount of capacity that the policy is intended to achieve. Moreover, such an exercise would suffer from circularity since the necessary level of policy payments needed to support target reasons are in part set by capacity price itself.

The third criterion is that the resource's Net CONE can be estimated accurately. If Net CONE is mis-estimated, the VRR curve will procure more or less capacity than desired. Accurate estimation depends on the certainty of plant designs and their costs and the ability to estimate E&AS offsets using market data. It also depends on the scalability of a standardized resource, not subject to rapid increases in costs as the best sites are exhausted, in which case the cost would depend strongly on penetration. Finally, estimation accuracy also depends on the capacity rating of resources relative to their nameplate. Lower ratings (i.e., low ELCC) magnify the effect of estimation errors on the cost per qualified MW.

Figure 3 summarizes these criteria and sub-criteria for evaluating each candidate resource type.

**FIGURE 3: REFERENCE RESOURCE SELECTION CRITIERIA**

**Feasible to build for the delivery year,** given local laws/regulations and technical factors

**Economic source of incremental capacity**
- Demonstrated by recent merchant entry, not in anomalous situations
- Not having a Net CONE much higher than other candidates
- Likely to remain economic through the end of the review period (2029/30)

**Costs, net E&AS revenues, and RA contribution per MW can be assessed accurately**
- Evidence of capital and operating costs exists from commercial experience
- Costs are uniform when scaled, rather than increasing steeply as best sites are exhausted
- Has stable UCAP/ICAP ratio or ELCC, rather than changing steeply with penetration or fleet composition
- Has high UCAP/ICAP ratio or ELCC, else uncertainties are amplified per kW UCAP
- Not largely dependent on revenues that are difficult to forecast (AS, energy volatility, RECs)

# II.B. Evaluation of Candidates against Criteria

The list of candidate technologies included gas-fired CTs and CCs, battery energy storage systems (BESS), hybrid photovoltaic (PV)-BESS, utility-scale PV, onshore wind, energy efficiency and demand response, uprates/conversions, and emerging technologies. Screening each of these against the evaluation criteria was straightforward in most cases, as shown in Table 1 below. For example, wind resources currently are not entering as a merchant resource without policy support in PJM, corresponding to its relatively high costs, and its Net CONE would be difficult to assess accurately due to its low ELCC rating that magnifies cost estimation errors. Energy efficiency, DR, and uprates/conversions were eliminated because of highly non-uniform costs across measures and sites, and scalability challenges with any particular type of measure.

**TABLE 1: INITIAL REFERENCE RESOURCE SCREENING ANALYSIS**

| Technology | Feasible to Build for DY | Economic Source of Capacity | Accuracy of Net CONE Estimates | Screening Decision |
|---|---|---|---|---|
| **Gas CC** | Yes | Yes | High | Consider as leading candidate |
| **Gas CT** | Yes | Unclear (few built, higher Net CONE) | High | Consider for further analysis |
| **Battery Storage** | Yes | Unclear (not standalone cleared in RPM) | Medium (falling costs; AS-dependence; ELCC stability?) | Consider for further analysis |
| **Hybrid PV-BESS** | Yes | Unclear (is any entering as merchant?) | Medium (REC-dependence; ELCC stability?) | Eliminate: Higher Net CONE uncertainty |
| **Utility-Scale PV** | Yes | Unclear (is any entering as merchant?) | Medium (REC-dependence; ELCC stability?) | Eliminate: Higher Net CONE uncertainty |
| **Wind** | Yes | Unclear (is any entering as merchant?) | Low (REC-dependence; low ELCC, stability) | Eliminate: Net CONE much higher than other technologies based on 2023/2024 MOPR |
| **Energy Efficiency/ DR** | Yes | Yes | Low (varies by site) | Eliminate: Inability to accurately estimate Net CONE |
| **Uprates/ Conversions** | Yes | Yes | Low (varies by site) | Eliminate: Inability to accurately estimate Net CONE |
| **Emerging Technologies** | No | None | Low | Eliminate: Infeasible to build |

Based on stakeholder feedback, we included one non-emitting resource in our CONE and E&AS analysis, selecting BESS due to its lower uncertainty in accurately estimating its Net CONE value compared to utility-scale solar PV and hybrid PV-BESS. Utility-scale solar PV ELCC values are highly uncertain as they decline significantly over the next 5-10 years based on the amount of entry that occurs in the PJM market, which is currently unknown. In addition, solar PV investments in PJM depend on RECs, the price of which is uncertain, which increases Net CONE uncertainty; REC prices also depend on capacity prices, creating a circularity that confounds estimating the capacity price at which PVs will enter. Hybrid PV-BESS resources are similarly uncertain as utility-scale solar PV in terms of the ELCC value and dependence on RECs for entry, plus the additional uncertainty of the configurations in which they will be built, including the relative scale of solar capacity to battery storage capacity and whether they will be AC-coupled versus DC-coupled or open-loop versus closed-loop.

That left CC, CT, and BESS as finalists. Ultimately, CCs best met the selection criteria, as summarized in Table 2 below. They are the most economic and are being built by developers. CTs continue not to be built, consistent with our estimate that their RTO Net CONE is about 20% higher than the CC, as shown in this report. In addition, CC Net CONE can be estimated relatively accurately. The conventional wisdom used to be that CCs are subject to more estimation error in E&AS Offsets, since their E&AS Offsets are larger. We disagree. The benchmark for "accuracy" should be the value that investors anticipate in the market. That benchmark is not directly observable, but there is more market data available to anticipate E&AS Offsets for CCs than CTs. CCs' net E&AS revenues can be fairly accurately approximated assuming 5x16 operation and applying observable futures prices for 5x16 on-peak blocks. No such benchmark is available for CTs that run less frequently when prices spike, so we rely on historical estimates that may not be representative of the future delivery year due to historical anomalies and evolving market conditions. Finally, CTs face less transparent gas procurement costs since they are committed and dispatched day-of.

**TABLE 2: BASIS FOR SELECTING THE RECOMMENDED REFERENCE RESOURCE**

| Technology | Feasible to Build for Delivery Year | Economic Source of Capacity | Accuracy of Net CONE Estimates |
|---|---|---|---|
| **Gas CC** | **Yes** | **Yes** (significant recent entry; lowest 2026/27 Net CONE) | **Highest** |
| **Gas CT** | **Yes** (may be infeasible to build in NJ) | **Unclear** (few recently built; Net CONE 20% higher than CC) | **High** (higher forward E&AS uncertainty due to lack of forward pricing matching CT dispatch) |
| **Battery Storage** | **Yes** | **Unclear** (no cleared capacity to date; highest 2026/27 Net CONE among candidates) | **Low** (uncertain future AS revenues; falling costs) |

We also considered "empirical Net CONE" based on the clearing price at which new capacity has proven willing to enter in the past several auctions. Historical data do indeed provide a useful reference point for Net CONE, although we rejected using it directly because it is backward-looking at a time when fundamentals are changing profoundly due to cost escalation and clean energy policies.

# III. Natural Gas-Fired Combined-Cycle Plants

## III.A. Technical Specifications

Similar to our approach in the 2014 and 2018 PJM CONE Study, we determined the characteristics of the reference resources primarily based on developers' "revealed preferences" for what is most feasible and economic in actual projects. However, because technologies and environmental regulations continue to evolve, we supplement our analysis with additional consideration of the underlying economics, regulations, infrastructure, and S&L's experience.

For determining most of the reference resource specifications, we updated our analysis from the 2018 study by examining CC plants built in PJM and the U.S. since 2018, including plants currently under construction. Plant location and emissions control technical specification assumptions across all CONE areas are based on the detailed analysis conducted in the 2018 PJM CONE study for the reference CC.[6] We characterized these plants by size, configuration, turbine type, cooling system, emissions controls, and fuel-firming.

For the specified locations within each CONE Area, we estimate the performance characteristics at a representative elevation and at a temperature and humidity that reflects peak conditions in the median year.[7] The assumed ambient conditions for each location are shown in Table 3.

[6] For a more detailed discussion on analysis related to reference CC location selection and Emissions control technology requirements, please refer to the 2018 PJM CONE study.

[7] The 50/50 summer peak day ambient condition data developed from National Climatic Data Center, Engineering Weather 2000 Interactive Edition, Asheville, NC, 2000. Adjustments were made for adapting the values to representative site elevation using J.V. Iribarne, and W.L. Godson, *Atmospheric Thermodynamics*, Second Edition (Dordrecht, Holland: D. Reidel Publishing Company, 1981).

TABLE 3: ASSUMED PJM CONE AREA AMBIENT CONDITIONS

| CONE Area | Elevation | Max. Summer Temperature | Relative Humidity |
|---|---|---|---|
| | *(ft)* | *(°F)* | *(%RH)* |
| **1 EMAAC** | 330 | 92.2 | 55.3 |
| **2 SWMAAC** | 150 | 96.2 | 44.2 |
| **3 Rest of RTO** | 990 | 89.9 | 49.7 |
| **4 WMAAC** | 1,200 | 91.4 | 48.9 |

Sources and notes: Elevation estimated by S&L based on geography of specified area. Summer conditions developed by S&L based on data from the National Climatic Data Center's Engineering Weather dataset.

Based on the assumptions discussed later in this section, the technical specifications for the CC reference resource is shown in Table 4. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 3.

TABLE 4: CC REFERENCE RESOURCE TECHNICAL SPECIFICATIONS

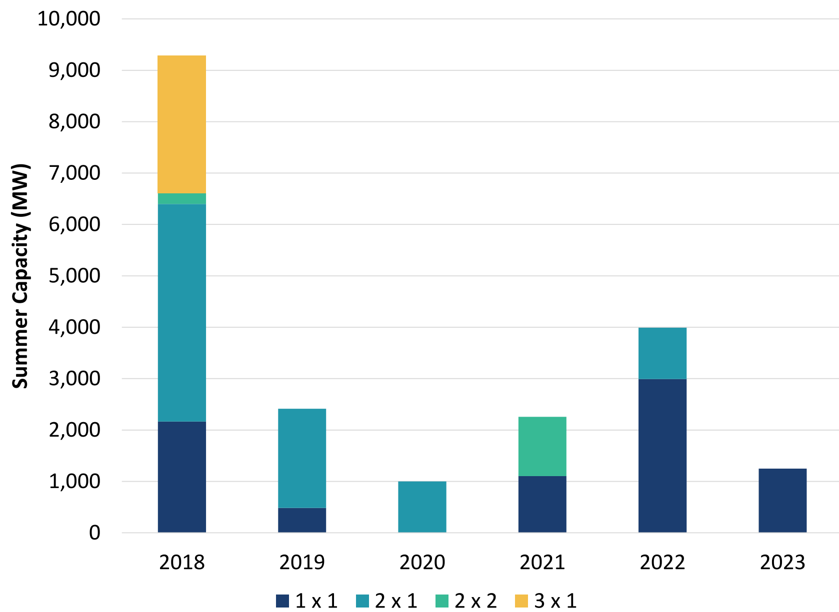
| Plant Characteristic | Specification |
|---|---|
| **Turbine Model** | GE 7HA.02 (CT), STF-A650 (ST) |
| **Configuration** | Double Train 1 x 1 |
| **Cooling System** | Dry Air-Cooled Condenser |
| **Power Augmentation** | Evaporative Cooling; no inlet chillers |
| **Net Summer ICAP (MW)** | |
| without Duct Firing | 1043 / 1047 / 1020 / 1011* |
| with Duct Firing | 1171 / 1174 / 1144 / 1133* |
| **Net Heat Rate (HHV in Btu/kWh)** | |
| without Duct Firing | 6365 / 6383 / 6359 / 6368* |
| with Duct Firing | 6602 / 6619 / 6593 / 6601* |
| **Environmental Controls** | |
| CO Catalyst | Yes |
| Selective Catalytic Reduction | Yes |
| **Dual Fuel Capability** | No |
| **Firm Gas Contract** | Yes |
| **Special Structural Requirements** | No |
| **Blackstart Capability** | None |
| **On-Site Gas Compression** | None |

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer ICAP and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

## III.A.1. Plant Size, Configuration, and Turbine Models

Since 2018, CC development has shifted from being primarily 2×1 configurations (two gas combustion turbines, one steam turbine) to 1×1 configurations (one gas combustion turbine, one steam turbine), as shown in Figure 4 below.

**FIGURE 4: GAS CC CONFIGURATIONS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018**




Sources and notes: Data is from Ventyx Energy Velocity Suite, Accessed August 2021.

1×1 CCs are in most cases being constructed with multiple trains at the same plant. Table 5 shows that double-train 1×1 CCs make up 42% of the capacity for 1×1 CCs that have been built or under construction since 2018 and the majority of the capacity currently under construction.

**TABLE 5: 1×1 GAS CC CAPACITY BY TRAINS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018**

| Number of Trains | 2018 *(MW)* | 2019 *(MW)* | 2020 *(MW)* | 2021 *(MW)* | 2022 *(MW)* | 2023 *(MW)* | Total Capacity *(MW)* | Capacity Share *(%)* |
|---|---|---|---|---|---|---|---|---|
| 1 | 1,184 | 485 | 0 | 1,104 | 0 | 0 | 2,774 | 35% |
| 2 | 980 | 0 | 0 | 0 | 1,116 | 1,250 | 3,346 | 42% |
| 3 | 0 | 0 | 0 | 0 | 1,875 | 0 | 1,875 | 23% |
| ***All CC Plants*** | **2,164** | **485** | **0** | **1,104** | **2,991** | **1,250** | **7,994** | **100%** |

Sources and notes: Data is from Ventyx Energy Velocity Suite, accessed August 2021. Double and triple train entries in represent a single plant, whereas single train 1×1 CCs represent multiple plants.

Based on the above empirical observations, we specify the CC reference resource to be a double-train 1×1. At the ambient conditions noted in Table 3, the double-train 1×1 CC maximum summer capacity ranges from 1,011 MW to 1,047 MW prior to considering supplemental duct firing, which is similar to the 2x1 CCs assumed in the previous PJM CONE studies.

While the turbine technology for each plant is specified in the tariff (*i.e.*, GE 7HA as the turbine model), we reviewed the most recent gas-fired generation projects and trends in turbine technology in PJM and the U.S. to consider whether to adjust this assumption.[8] For the reference CC, we maintain the assumption of GE H-class turbines from the 2018 PJM CONE study based on continuing shifts away from the F-class and G-class frame type turbines toward the similar but larger H-class and J-class turbines. We provide a more detailed discussion on recent developer preferences for H-class and J-class turbine since 2018 in Appendix A.

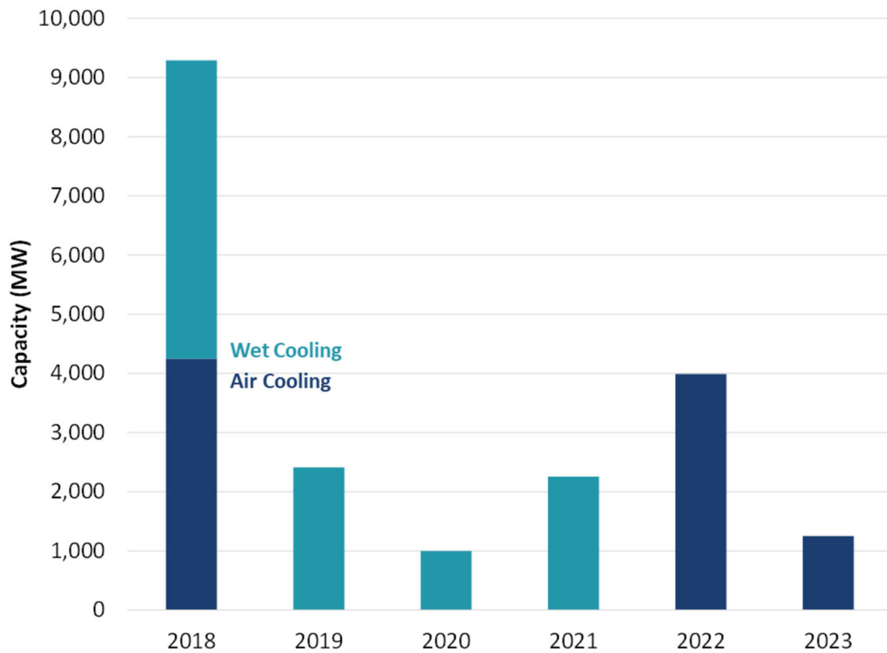
### III.A.2. Cooling System

For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell dry air-cooled condenser (ACC). ACC technology differs from traditional water-cooled condensers that utilize "wet" cooling towers for heat rejection. Dry ACCs will tend to be larger and more costly but minimize the water usage. Reduced water consumption is advantageous in areas where water is scarce, expensive to procure, or where it may be difficult to obtain withdrawal permits for the volumes expended by a wet cooling system.

Figure 5 shows the recent trends among actual projects with all of the plants under construction now having dry air-cooled condensers, reflecting that cooling towers have become more difficult to permit.

[8] PJM 2017 OATT, Part 1 - Common Services Provisions, Section 1 - Definitions.

FIGURE 5: COOLING SYSTEM FOR CC CAPACITY IN PJM BUILT OR UNDER CONSTRUCTION SINCE 2018




Sources and notes: Data downloaded from Ventyx's Energy Velocity Suite August 2021. Includes only status operational plants (operating, under construction, site prep, converted, standby, testing, steam only, restarted)

## III.A.3. Emissions Controls

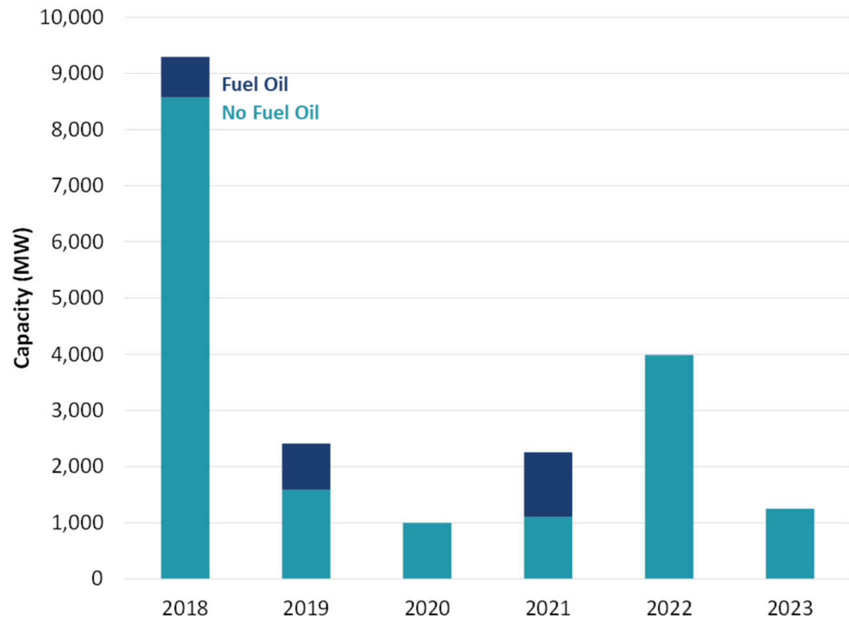
The reference CC is assumed to utilize selective catalytic reduction (SCR) systems as a nitrogen oxide (NOx) emissions control technology and CO catalyst systems as a carbon monoxide (CO) emissions control technology. The SCR system and CO catalyst adds an incremental cost of $72 million (in 2021 dollars) to the capital costs. A more detailed discussion of emissions controls can be found in the 2018 PJM CONE study.

## III.A.4. Fuel Supply

Natural gas-fired plants can be designed to operate solely on gas or with “dual-fuel” capability to burn either gas or diesel fuel oil. Dual-fuel plants can switch to oil when gas becomes unavailable or prohibitively costly due to pipelines becoming fully utilized and congested. Plants without dual-fuel capability can ensure access to their fuel supply through firm transportation contracts, although such contracts cost more than dual-fuel capability in most locations.[9]

Developers have moved away from installing dual-fuel capability on new CCs. Figure 6 below shows that only 13% of CC capacity built or under construction in PJM installed fuel oil as a secondary fuel since 2018; data from PJM confirms that almost all are instead firming their availability with firm gas transportation contracts.

**FIGURE 6: DUAL-FUEL CAPABILITY FOR CC CAPACITY IN PJM BUILT OR UNDER CONSTRUCTION SINCE 2018**




Sources and notes: Data downloaded from Ventyx's Energy Velocity Suite August 2021. Includes only status operational plants (operating, under construction, site prep, converted, standby, testing, steam only, restarted).

Instead, we assume that the CC will obtain firm transportation service to ensure fuel supply during tight market conditions. Based on confidential data provided by PJM, nearly all new gas-fired plants that entered the market since the 2016/2017 BRA obtain firm transportation service to ensure adequate fuel supply.[10] Based on these trends, we updated our assumption from the

9 Eastern Interconnection Planning Collaborative, "Fuel Assurance: Dual Fuel Capability and Firm Transportation Alternatives," accessed September, 2017, http://nebula.wsimg.com/ef3ad4a531dd905b97af83ad78fd8ba7?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1

10 PJM provided the fuel supply arrangements for 20,848 MW of new gas plants that first cleared the capacity market in the 2016/2017 BRA to the 2020/2021 BRA, including firm transportation, dual fuel capability, and installing gas laterals to multiple pipelines.

2018 PJM CONE study for the CC reference resource to obtain firm gas supply across all CONE areas.[11] The costs of firm transportation service are incurred annually, so we include these costs as fixed operations and maintenance costs in the following section.

## III.B. Capital Costs

Plant capital costs are costs incurred when constructing the power plant before the commercial online date. Power plant developers typically hire an engineering, procurement, and construction (EPC) company to complete construction and to ensure the plant operates properly. EPC costs include major equipment, labor, and materials, and non-EPC or owner's costs include development costs, startup costs, interconnection costs, and inventories.

All equipment and material costs are initially estimated by S&L in 2021 dollars using S&L proprietary data, vendor catalogs, or publications. Both labor rates and materials costs have been estimated for the specific counties chosen as representative of each CONE Area. Estimates for the number of labor hours and quantities of material and equipment needed to construct combined-cycle plants are based on S&L experience on similarly sized and configured facilities and are explained in further detail in Appendix A.

Based on the monthly construction drawdown schedule, we estimate the overnight capital cost for an online date of June 1, 2026 by escalating the 2021 costs using escalation rates provided by Sargent & Lundy. The 2026 "installed cost" is the present value of the construction period cash flows as of the end of the construction period, using the monthly drawdown schedule and the cost of capital for the project.

Based on the technical specifications for the reference CC described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 6 below. The maximum variation between overnight capital costs between CONE areas is $100/kW, similar to the $94/kW from the 2018 PJM CONE study. The methodology and assumptions for developing the capital cost line items are described further below.

[11] We recommended in the 2018 PJM CONE study dual-fuel capabilities in all CONE Areas except SWMAAC. PJM chose to adopt CONE values that incorporated dual-fuel capabilities.

**TABLE 6: PLANT CAPITAL COSTS FOR CC REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE**

| Capital Costs (in $millions) | CONE Area 1 EMAAC *1171 MW* | 2 SWMAAC *1174 MW* | 3 Rest of RTO *1144 MW* | 4 WMAAC *1133 MW* |
|---|---|---|---|---|
| **Owner Furnished Equipment** | | | | |
| Gas Turbines | $155.3 | $155.3 | $155.3 | $155.3 |
| HRSG / SCR | $80.7 | $80.7 | $80.7 | $80.7 |
| Sales Tax | $0.0 | $0.0 | $0.0 | $0.0 |
| **Total Owner Furnished Equipment** | **$320.7** | **$320.7** | **$320.7** | **$320.7** |
| **EPC Costs** | | | | |
| Equipment | | | | |
| Other Equipment | $86.3 | $86.3 | $86.3 | $86.3 |
| Construction Labor | $365.5 | $283.3 | $297.1 | $330.5 |
| Other Labor | $75.5 | $69.0 | $70.1 | $72.7 |
| Materials | $75.5 | $75.5 | $75.5 | $75.5 |
| Sales Tax | $0.0 | $0.0 | $0.0 | $0.0 |
| EPC Contractor Fee | $98.5 | $89.6 | $91.1 | $94.7 |
| EPC Contingency | $108.4 | $98.6 | $100.2 | $104.2 |
| **Total EPC Costs** | **$871.4** | **$763.9** | **$782.0** | **$825.6** |
| **Non-EPC Costs** | | | | |
| Project Development | $59.6 | $54.2 | $55.1 | $57.3 |
| Mobilization and Start-Up | $11.9 | $10.8 | $11.0 | $11.5 |
| Net Start-Up Fuel Costs | -$13.9 | -$14.0 | -$9.8 | -$13.5 |
| Electrical Interconnection | $25.3 | $25.4 | $24.7 | $24.5 |
| Gas Interconnection | $33.7 | $33.7 | $33.7 | $33.7 |
| Land | $2.2 | $1.8 | $1.0 | $1.8 |
| Fuel Inventories | $0.0 | $0.0 | $0.0 | $0.0 |
| Non-Fuel Inventories | $6.0 | $5.4 | $5.5 | $5.7 |
| Owner's Contingency | $10.0 | $9.4 | $9.7 | $9.7 |
| Emission Reduction Credit | $2.3 | $2.3 | $2.3 | $2.3 |
| Financing Fees | $29.2 | $26.7 | $27.2 | $28.1 |
| **Total Non-EPC Costs** | **$166.4** | **$155.8** | **$160.6** | **$161.3** |
| **Total Capital Costs** | **$1,358.5** | **$1,240.5** | **$1,263.3** | **$1,307.6** |
| **Overnight Capital Costs ($million)** | **$1,359** | **$1,240** | **$1,263** | **$1,308** |
| **Overnight Capital Costs ($/kW)** | **$1,160** | **$1,057** | **$1,104** | **$1,154** |
| **Installed Cost ($/kW)** | **$1,255** | **$1,144** | **$1,195** | **$1,248** |

## III.B.1. EPC Capital Costs

### III.B.1.i. Project Developer and Contract Arrangements

Costs that are typically within the scope of an EPC contract include the major equipment (gas turbines, heat recovery steam generator (HRSG), condenser, and steam turbine), other equipment, construction and other labor, materials, sales tax, contractor's fee, and contractor's contingency.

The contracting scheme for procuring professional EPC services in the U.S. is typically implemented with a single contractor at a single, fixed, lump-sum price. A single contract reduces the owner's responsibility with construction coordination and reduces the potential for missed or duplicated scope compared to multiple contract schemes. The estimates and contractor fees herein reflect this contracting scheme.

### III.B.1.ii. **Equipment and Materials**

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines. The major equipment includes "owner-furnished equipment" (OFE) purchased by the owner through the EPC. OFE costs include EPC handling costs contingency on logistics, installation, delivery, *etc.*, with no EPC profit markup on the major equipment cost itself. "Other equipment" includes inside-the-fence equipment required for interconnection and other miscellaneous equipment and associated freight costs. Equipment costs, including the combustion turbine costs, are based on S&L's proprietary database and continuous interaction with clients and vendors regarding equipment costs and budget estimates. We assume all purchases for plant equipment are exempt from sales tax.

The balance of plant EPC equipment and material costs were estimated using S&L proprietary data, vendor catalogs, and publications. The balance of plant equipment consists of all pumps, fans, tanks, skids, and commodities required for operation of the plant. Estimates for the quantity of material and equipment needed to construct simple- and combined-cycle plants are based on S&L experience on similarly sized and configured facilities.

### III.B.1.iii. **Labor**

Labor consists of "construction labor" associated with the EPC scope of work and "other labor," which includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. "Materials" include all construction materials associated with the EPC scope of work, material freight costs, and consumables during construction.

Similar to the 2018 PJM CONE Study, the labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Instead, S&L developed labor rates through a survey of the prevalent wages in each region in 2021, including both union and non-union labor. The labor costs are based on average labor rates weighted by the combination of trades required for each plant type. We provide a more detailed discussion of the inputs into the labor cost estimates in Appendix A.

#### III.B.1.iv. **EPC Contractor Fee and Contingency**

The "EPC Contractor's fee" is added compensation and profit paid to an EPC contractor for coordination of engineering, procurement, project services, construction management, field engineering, and startup and commissioning. This fee is applied to the Owner Furnished Equipment to account for the EPC costs associated with the tasks listed above once the equipment is turned over by the Owner to the EPC contractor. Capital cost estimates include an EPC contractor fee of 10% of total EPC and OFE costs for CC facilities based on S&L's proprietary project cost database.

"Contingency" covers undefined variables in both scope definition and pricing that are encountered during project implementation. Examples include nominal adjustments to material quantities in accordance with the final design; items clearly required by the initial design parameters that were overlooked in the original estimate detail; and pricing fluctuations for materials and equipment. Our capital cost estimates include an EPC contingency of 10% of total EPC and OFE costs, including the contractor fee. The overall contingency rate in this analysis (including the Owner's Contingency presented in the next section) is 9.7% to 9.8% of the pre-contingency overnight capital costs.

### III.B.2. Non-EPC Costs

"Owner's capital costs" include all other capital costs not expected to be included in the EPC contract, including development costs, legal fees, gas and electric interconnections, and inventories.

#### III.B.2.i. **Project Development and Mobilization and Startup**

Project development costs include items such as development costs, oversight, and legal fees that are required prior to and generally through the early stages of plant construction. We assume project development costs are 5% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

Mobilization and startup costs include those costs incurred by the owner of the plant towards the completion of the plant and during the initial operation and testing prior to operation, including the training, commissioning, and testing by the staff that will operate the plant going forward. We assume mobilization and startup costs are 1% of the total EPC costs, based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

### III.B.2.ii. Net Startup Fuel Costs

Before commencing full commercial operations, the new CC plants must undergo testing to ensure the plant is functioning and producing power correctly. This occurs in the months before the online date and involves testing the turbine generators on natural gas. S&L estimated the fuel consumption and energy production during testing for each plant type based on typical schedule durations and testing protocols for plant startup and commissioning, as observed for actual projects. A plant will pay for the natural gas, and will receive revenues for its energy production. We provide additional detail on the calculation of the net startup fuel costs in Appendix A.

### III.B.2.iii. Emission Reduction Credits

Emission Reduction Credits (ERCs) must be obtained for new facilities located in non-attainment areas. ERCs may be required for projects located in the ozone transport region even if the specific location is in an area classified as attainment. ERCs must be obtained prior to the start of operation of the unit and are typically valid for the life of the project; thus, ERC costs are considered to be a one-time expense. ERCs are determined based on the annual NOx and volatile organic compounds (VOC) emissions of the facility and offset ratio which is dependent on the specific plant location. Similar to our assumption from the 2018 PJM CONE study, we assumed a cost of $5,000/ton for all CONE Areas and an offset ratio of 1.15 for NOx and VOC emissions, resulting in a one-time cost of $2 million (in 2021 dollars) prior to beginning operation of the CC plants. While ERC costs are likely to vary by project and by location, there is insufficient publicly available cost data to support a more refined cost estimate for each CONE Area.

### III.B.2.iv. Gas and Electric Interconnection

We estimated gas interconnection costs based on cost data for gas lateral projects similar to the interconnection of a greenfield plant. We assume the gas interconnection will require a metering station and a five-mile lateral connection, similar to the 2018 PJM CONE Study. From the data summarized in Appendix A, we estimate that gas interconnection costs will be $29.5 million (in 2021 dollars) based on $5.1 million/mile and $4.0 million for a metering station. Similar to the 2011, 2014, and 2018 PJM CONE studies, we found no relationship between pipeline width and per-mile costs in the project cost data.

We estimated electric interconnection costs based on historic electric interconnection cost data provided by PJM. Electric interconnection costs consist of two categories: direct connection costs and network upgrade costs. Direct connection costs will be incurred by any new project connecting to the network and includes all necessary interconnection equipment such as generator lead and substation upgrades. Network upgrade costs may be incurred when improvements, such as replacing substation transformers, are required. Using recent project data provided by PJM with the online service year between 2018 and 2021, we selected 17 projects (3,700 MW of total capacity) that are representative of interconnection costs for a new gas CCs and calculated a capacity-weighted average electrical interconnection cost of $18.9/kW (in 2021 dollars) for these projects, 5% lower than the 2018 PJM CONE Study. The estimated electric interconnection costs are between $21.4 and $22.2 million for CCs (in 2021 dollars). Appendix A presents additional details on the calculation of electric interconnection costs.

### III.B.2.v. **Land**

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. We assume that 60 acres of land are required for the CC. Table 7 shows the resulting costs (see Appendix A for more detail).

**TABLE 7: COST OF LAND PURCHASED FOR REFERENCE CC**

| CONE Area | Land Price *($/acre)* | Plot Size Gas CC *(acres)* | Cost Gas CC *($m)* |
|---|---|---|---|
| 1 EMAAC | $36,600 | 60 | $2.20 |
| 2 SWMAAC | $29,500 | 60 | $1.77 |
| 3 Rest of RTO | $16,400 | 60 | $0.98 |
| 4 WMAAC | $30,600 | 60 | $1.84 |

Sources and notes: We assume land is purchased in 2022, i.e., 6 months to 1 year before the start of construction.

### III.B.2.vi. **Non-Fuel Inventories**

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. We assume non-fuel inventories are 0.5% of EPC costs based on S&L's review of similar projects for which it has detailed information on actual owner's costs.

### III.B.2.vii. **Owner's Contingency**

Owner's contingencies are needed to account for various unknown costs that are expected to arise due to a lack of complete project definition and engineering. Examples include permitting complications, greater than expected startup duration, *etc.* Similar to our assumption in the 2018 PJM CONE Study, we assumed an owner's contingency of 8% of Owner's Costs based on S&L's review of the most recent projects for which it has detailed information on actual owner's costs.

#### III.B.2.viii. Financing Fees

Financing fees are the cost of acquiring the debt financing, including associated financial advisory and legal fees. Financing fees are considered part of the plant overnight costs, whereas interest costs and equity costs during construction are part of the total capital investment cost, or "installed costs" but not part of the overnight costs. We assume financing costs are 4% of the EPC and non-EPC costs financed by debt, which is typical of recent projects based on S&L's review of similar projects for which it has detailed information on actual owner's costs. As explained below, the project is assumed to be 55% debt financed and 45% equity financed.

### III.B.3. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 32 months for CCs.[12] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term historical trends relative to the general inflation rate for equipment and materials and labor. We forecast that labor costs will continue to climb at recent rates (1.6% real per year) over the next several years, while materials and equipment suppliers will lock in the higher costs but not rise as quickly as they have over the past few years.

We calculated the inflation rate for escalating the capital costs estimated in January 2022 to the middle of the project development period (November 2024) based on the inflation that occurred since January, as reported by the Bureau of Labor Statistics, and the inflation forecasted by the Blue Chip Economic Indicators in March 2022, in which inflation starts at over 4% on an annualized basis before levelling off at 2.2% in the longer-term. Based on these sources, we assumed for the CONE calculations an annualized long-term inflation rate of 2.91% for 2022 to

[12] The construction drawdown schedule occurs over 32 months with 82% of the costs incurred in the final 18 months prior to commercial operation.

2026.[13] The real escalation rate for each cost category was then added to the assumed inflation rate to determine the nominal escalation rates, as shown in Table 8.

**TABLE 8: CC AND CT CAPITAL COST ESCALATION RATES (% PER YEAR)**

| Capital Cost Component | Real Escalation Rate | Nominal Escalation Rate |
|---|---|---|
| Equipment and Materials | 0.00% | 2.91% |
| Labor | 1.60% | 4.51% |

*Sources and notes*: Escalation rates on equipment and materials costs are derived from the BLS Producer Price Index.

To reflect the timing of the costs a developer accrues during the construction period, we escalated most of the capital cost line items from the current overnight costs to the month they would be incurred using the monthly capital drawdown schedule developed by S&L for an online date in June 2026.

We escalated several cost items in a different manner:

- Land: assume land will be purchased 6 months to 1 year prior to the beginning of construction; for a June 2026 online date, the land is thus assumed to be purchased in late 2022 such that current estimates are escalated 1 year using the long-term inflation rate of 2.9%.
- Net Start-Up Fuel and Fuel Inventories: no escalation was needed as we forecasted fuel and electricity prices in 2026 dollars.
- Electric and Gas Interconnection: assume the construction of electric interconnection occurs 7 months prior to project completion while gas interconnection occurs 8 months prior to completion, consistent with the 2018 PJM CONE Study; the interconnection costs have been escalated specifically to these months.
- Emission Reduction Credits: escalated to the online start date of June 2026 using the long-term inflation rate of 2.91%.

We used the drawdown schedule to calculate debt and equity costs during construction to arrive at a complete "installed cost." The installed cost for each technology is calculated by first applying the monthly construction drawdown schedule for the project to the 2026 overnight capital cost and then finding the present value of the cash flows as of the end of the construction period using the assumed cost of capital as the discount rate. By using the ATWACC to calculate

13 The near-final CONE results presented on March 25, 2022 assumed an inflation rate of 2.0%.

the present value, the installed costs will include both the interest during construction from the debt-financed portion of the project and the cost of equity for the equity-financed portion.

# III.C. Operations and Maintenance Costs

Once the plant enters commercial operation, the plant owners incur fixed O&M costs each year, including contracted services, property tax, insurance, labor, maintenance, and asset management. Annual fixed O&M costs increase the CONE. Separately, we calculated *variable* O&M costs (including maintenance, consumables, and waste disposal costs) tied directly to unit operations to inform PJM's future E&AS margin calculations.

## III.C.1. Summary of O&M Costs

Table 9 summarizes the fixed and variable O&M for CCs with an online date of June 1, 2026.

**TABLE 9: O&M COSTS FOR CC REFERENCE RESOURCE**

| | CONE Area | | | |
|---|---|---|---|---|
| **O&M Costs** | **1 EMAAC** *1171 MW* | **2 SWMAAC** *1174 MW* | **3 Rest of RTO** *1144 MW* | **4 WMAAC** *1133 MW* |
| **Fixed O&M (2026$ million)** | | | | |
| LTSA Fixed Payments | $0.8 | $0.8 | $0.8 | $0.8 |
| Labor | $5.2 | $5.6 | $4.0 | $4.1 |
| Maintenance and Minor Repairs | $6.6 | $6.7 | $6.0 | $6.1 |
| Administrative and General | $1.4 | $1.4 | $1.2 | $1.2 |
| Asset Management | $1.6 | $1.7 | $1.2 | $1.2 |
| Property Taxes | $3.0 | $16.4 | $9.5 | $2.9 |
| Insurance | $8.2 | $7.4 | $7.6 | $7.8 |
| Firm Gas Contract | $10.0 | $12.4 | $16.4 | $14.5 |
| Working Capital | $0.2 | $0.1 | $0.1 | $0.1 |
| **Total Fixed O&M (2026$ million)** | **$36.8** | **$52.6** | **$46.8** | **$38.8** |
| **Levelized Fixed O&M (2026$/MW-yr)** | **$31,500** | **$44,900** | **$40,900** | **$34,200** |
| **Variable O&M (2026$/MWh)** | | | | |
| Consumables, Waste Disposal, Other VOM | 0.76 | 0.76 | 0.77 | 0.77 |
| **Total Variable O&M (2026$/MWh)** | **2.08** | **2.07** | **2.12** | **2.14** |

## III.C.2. Annual Fixed Operations and Maintenance Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance).

### III.C.2.i. Plant Operation and Maintenance

We estimated the labor, maintenance and minor repairs, and general and administrative costs based on a variety of sources, including S&L's proprietary database on actual projects, vendor publications for equipment maintenance, and data from the Bureau of Labor Statistics.

Major maintenance is assumed to be completed through a long-term service agreement (LTSA) with the original equipment manufacturer that specifies when to complete the maintenance based on either fired-hours or starts. Consistent with past CONE studies and PJM market rules, we include the monthly payments specified in the LTSA as fixed O&M costs and the larger costs associated with run-time and starts as variable O&M.

### III.C.2.ii. Insurance and Asset Management Costs

We estimate insurance cost of 0.6% of the overnight capital cost per year, from the 2018 PJM CONE study based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer. We estimated the asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services from a sample of natural gas-fired plants in operation.

### III.C.2.iii. Property Tax

We maintained our bottom-up approach for estimating property and personal taxes from the 2018 PJM CONE study. We researched tax regulations for the locations selected in each CONE Area, averaging the tax rates in the areas that include multiple states.[14] The tax rates assumed for each CONE Area are summarized in Table 10 with additional details in Appendix A.

[14] See the 2018 PJM CONE study for a detailed discussion on our bottom up approach.

**TABLE 10: PROPERTY TAX RATE ESTIMATES FOR EACH CONE AREA**

| | Real Property Tax | Personal Property Tax | |
|---|---|---|---|
| | Effective Tax Rate | Effective Tax Rate | Depreciation |
| | *(%)* | *(%)* | *(%/yr)* |
| **1 EMAAC** | | | |
| New Jersey | 3.8% | n/a | n/a |
| **2 SWMAAC** | | | |
| Maryland | 1.1% | 1.3% | 3.30% |
| **3 RTO** | | | |
| Ohio | 1.9% | 1.3% | See "SchC-NewProd (NG)" Annual Report |
| Pennsylvania | 2.7% | n/a | n/a |
| **4 WMAAC** | | | |
| Pennsylvania | 3.8% | n/a | n/a |

Sources and notes: See Appendix A for additional detail on inputs and sources.

We assume that assessed value of real property will escalate in future years with inflation. We assume that the initial assessed value of the property is the plant's total capital cost (exclusive of real property). The assessed value of personal property is subject to depreciation in future years.

### III.C.2.iv. **Working Capital**

Based on our approach in the 2018 PJM CONE study, we estimate the costs of maintaining the working capital requirement assuming that the working capital requirement is approximately 0.5% of overnight costs and a borrowing rate for short-term debt of 2.1%.[15]

### III.C.2.v. **Firm Transportation Service Contracts**

We maintained our approach for estimating firm transportation service contracts from the 2018 PJM CONE study for the SWMAAC CONE Area for the reference CC. However, we utilized the reservation and usage charges for pipelines servicing EMAAC, Rest of RTO, and WMAAC under FT-1 rate schedules. Table 11 summarizes the pipelines we assumed for each CONE area and the representative firm gas capacity costs. We assume the reference CC commit to procuring firm gas transportation on an annual basis.

[15] 15-day average 3-month bond yield as of January 31, 2022, BFV USD Composite (BB), from Bloomberg.

TABLE 11: CONE AREA PIPLEINES AND FIRM GAS CAPACITY COSTS

| | CONE Area | Pipelines | Representative Firm Gas Capacity Cost *(2026$ per Dth/d per Mth)* |
|---|---|---|---|
| 1 | **EMAAC** | Transco Zone 6 (non-NY), Transco Zone 6 (NY) | $4.50 |
| 2 | **SWMAAC** | Dominion Cove Point | $5.56 |
| 3 | **Rest of RTO** | Chicago, Columbia-Appalachia TCO, Dominion South, Michcon, Transco Zone 5 | $7.54 |
| 4 | **WMAAC** | Tennessee 500L, TETCO M3 | $6.73 |

To estimate the costs of acquiring firm transportation service for SWMAAC we escalated the Cost of Firm Gas Capacity per Month of $4.96 (2022$ per Dth/d) from the 2018 PJM CONE study by 2.9% annually to 2026. For the EMAAC, Rest of RTO, and WMAAC CONE Areas, we combined the reservation and usage rates, resulting in a tariff rate for each pipeline. Then the pipeline tariff rates are averaged and escalated by 2.9% annually to 2026 by CONE area to calculate the representative firm gas capacity. We provide additional detail on the cost calculation of acquiring firm transportation service in Appendix A.

## III.C.3. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they are inputs to the calculation of the E&AS revenue offset performed by PJM. Variable O&M costs are directly proportional to plant generating output, such as SCR catalyst and ammonia, CO oxidation catalyst, water, and other chemicals and consumables. As discussed above, we assume that the major maintenance costs related to the unit run-time and starts are variable O&M costs, consistent with past CONE studies.

## III.C.4. Escalation to 2026 Costs

Inflation rates affect our CONE estimates by forming the basis for projected increases in various fixed O&M cost components over time. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category. The same real escalation rates used to escalate the overnight capital costs in the previous section (see Table 8) have been used to escalate the O&M costs. The assumed real escalation rate for O&M line items that are primarily labor-based is 1.6% per year, while those for other O&M costs remain constant in real terms.

# III.D. Financial Assumptions

## III.D.1. Cost of Capital

An appropriate discount rate is needed for translating uncertain future cash flows into present values and deriving the CONE value that makes the project net present value (NPV) zero. It is standard practice to discount future all-equity cash flows (*i.e.*, without deducted interest payments) using an after-tax weighted-average cost of capital (ATWACC).[16] Consistent with our approach in previous CONE studies, we developed our recommended cost of capital by an independent estimation of the ATWACC for publicly-traded merchant generation companies or independent power producers (IPPs), supplemented by additional market evidence from recent merger and acquisition transactions.[17] Based on our empirical analysis as of March 31, 2022, we recommend 8.0% as the appropriate ATWACC to set the CONE price for a new merchant plant that will commence operation by 2026 (4.5 years from now assuming a mid-year commercial operation). Consistent with this ATWACC determination, we recommend the following specific components for a new merchant plant: a capital structure of 55/45 debt-equity ratio, cost of debt 4.7%, a combined federal and state tax rate of 27.7%, and return on equity (ROE) of 13.6%.[18] It is important to emphasize that the exact capital structure and corresponding cost of debt and ROE do not significantly affect the CONE calculation as long as they amount to the empirically-based 8.0% ATWACC.[19] This is because the CONE value is determined by the 8.0% ATWACC, not by the ATWACC components. Nonetheless, we use market observations and judgements to select a set of self-consistent components of the ATWACC.

As a point of reference, we compare our current ATWACC recommendation to recommendations in our prior PJM CONE studies in Figure 7. The red circles (35% federal tax rate for 2011 and

[16] The ATWACC is so-named because it accounts for both the cost of equity and the cost of debt, net of the tax deductibility of interest payments on debt, with the weights corresponding to the debt-equity ratio in the capital structure. Cash flows to which the ATWACC is applied must include revenues, costs, and taxes on income net of depreciation (but not accounting for interest payments or their deductibility, since that is incorporated into the ATWACC itself).

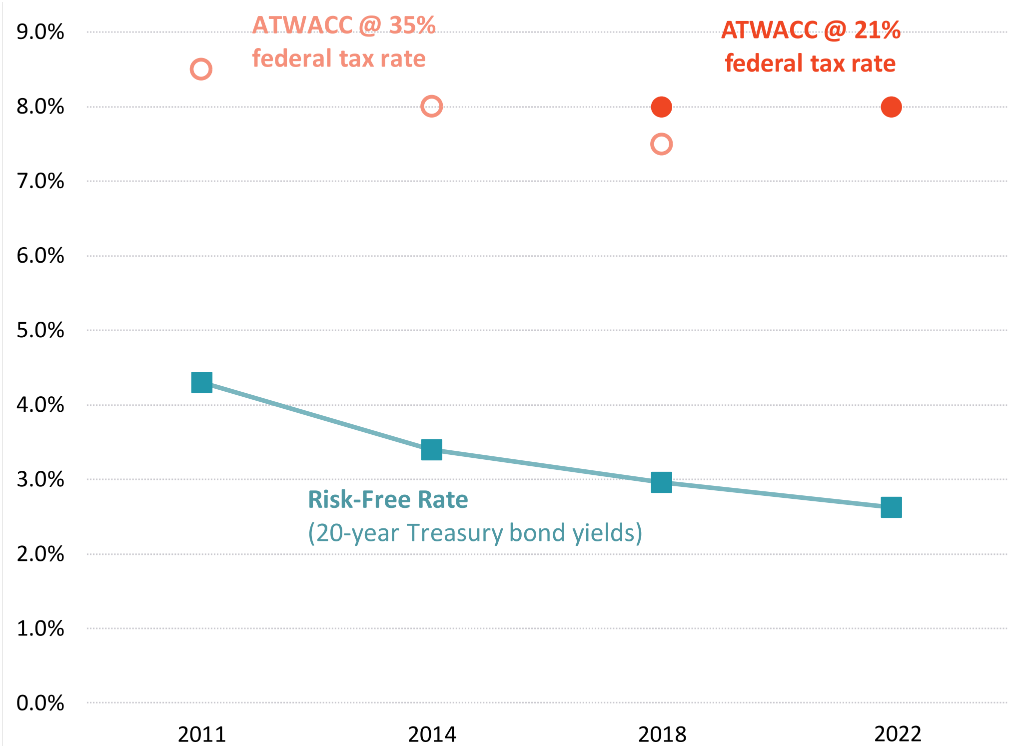
[17] Supplementing our ATWACC analysis with estimates from other financial analysts is valuable as others' methodologies may account for market risks and estimation uncertainties differently from ours.

[18] 4.7% × 55% × (1 – 27.7%) + 13.6% × 45% = 8.0%. The tax rate of 27.7% is a combined federal-state tax rate, where state taxes are deductible for federal taxes (= 8.5% + (1 – 8.5%) × 21%). Note that the ATWACC applied to the four CONE Areas varies slightly with applicable state income tax rates, as discussed in the next section.

[19] Finance theory posits that, over a reasonable range, capital structure does not affect the cost of capital: for a given project or business, greater leverage will increase the cost of debt and cost of equity such that the ATWACC would remain the same.

2014) and dots (21% tax rate for 2018 and 2022) represent the recommended ATWACCs, and the line is the prevailing risk-free rate (20-year Treasury rate).

FIGURE 7: COMPARISON OF BRATTLE ATWACC RECOMMENDATIONS FOR PJM




Sources: 2011, 2014, and 2018 values based on previous PJM CONE studies.

Over the last decade, our recommended ATWACC of merchant generation was 8.5% in 2011, then dropped and stayed at 8% between 2014 and 2022. These changes are driven by changes in both business risks of the industry, and market risks such as the risk-free rate and corporate income tax rates.

- We lowered the ATWACC from 8.5% to 8% in 2014 because the 20-year Treasury rate dropped from 4.3% in 2011 to 3.4% in 2014.
- The 20-year Treasury rate dropped further in 2018 to 3.0%. However, we kept our ATWACC recommendation at 8%, because the reduction in federal corporate income tax rate, from 35% to 21% starting from 2018, increases the ATWACC.
- The 20-year Treasury rate dropped again in 2022 to 2.6% as of March 2022. However, the top of the ATWACC range from the sample (the business risk of the merchant generation industry) and the additional reference points approximates 8.0% (Figure 8).

In Table 12, we compare our current recommended costs of capital components to those in our prior PJM CONE studies. The changes in the return of equity (ROE) are based on a number of factors: our recommended ATWACC, the federal-state combined tax rate, cost of debt, and the debt/equity ratios.

**TABLE 12: COMPARISON OF COST OF CAPITAL RECOMMENDATIONS**

| Study Year | Tax Rate | Return on Equity | Equity Ratio | Cost of Debt | Debt Ratio | ATWACC |
|---|---|---|---|---|---|---|
| 2011 | 40.5% | 12.5% | 50% | 7.5% | 50% | 8.5% |
| 2014 | 40.5% | 13.8% | 40% | 7.0% | 60% | 8.0% |
| 2018 | 27.7% | 13.0% | 45% | 5.5% | 55% | 8.0% |
| 2022 | 27.7% | **13.6%** | 45% | **4.7%** | 55% | 8.0% |

The rest of this section further describes our approach to developing the recommended ATWACC. First, we perform an independent cost of capital analysis for U.S. IPPs. Second, we present evidence on the discount rates disclosed in fairness opinions for two recent merger and acquisition transactions involving U.S. IPPs.[20] Third, we discuss how considerations of the specific dynamics of PJM markets affect cost of capital recommendations.

**ATWACC for Publicly Traded Companies as of March 31, 2022**: We estimated ATWACC using the following standard techniques, with the base-case results summarized in Table 13 and charted with sensitivities in Figure 8. Base-case estimates are derived from three publicly-traded companies with significant portfolios of merchant generation. The sample ATWACC ranges from 6.3% for AES to 7.6% for NRG. Additional details about the sample and key inputs are discussed next.

[20] We do not include private equity investors in our sample because their cost of equity cannot be observed in market data and private equity investment portfolios typically consist of investments in many different projects in many different industries. Nor do we include electric utilities in cost-of-service regulated businesses, as their businesses are mostly cost-of-service regulated with lower risks and a lower cost of capital than merchant generation.

**TABLE 13: BASE-CASE ATWACC - 2022**

| Company | S&P Credit Rating [1] | Market Capitalization [2] | Long Term Debt [3] | Beta [4] | CAPM Cost of Equity [5] | Equity Ratio [6] | Cost of Debt [7] | ATWACC [8] |
|---|---|---|---|---|---|---|---|---|
| AES Corp | BBB- | $15,862 | $17,754 | 1.10 | 10.8% | 41% | 4.3% | 6.3% |
| NRG Energy Inc | BB+ | $9,179 | $8,202 | 1.15 | 11.2% | 53% | 4.9% | 7.6% |
| Vistra Corp | BB | $10,117 | $10,515 | 1.10 | 10.8% | 47% | 5.2% | 7.1% |

Sources & Notes:
[1]: S&P Research Insight.
[2] and [3]: Bloomberg as of 3/31/2022, millions USD.
[4]: Value Line.
[5]: RFR (2.62%) + [4] × MERP (7.46%).
[6]: Equity as a percentage of total firm value.
[7]: Cost of Debt based on Company Cost of Debt for AES, NRG and Vistra.
[8]: [5] × [6] + [7] × (1 - [6]) × (1 - tax rate).

*Sample:* Our sample consists of three companies: NRG, Vistra, and AES. Since 2018, there are no longer any pure-play merchant generation companies in the US. In 2018, Calpine was taken private by a consortium of private investors, and Dynegy was acquired by Vistra. The new Vistra includes both electricity generation and retail electricity supply. In addition, NRG expanded into competitive retail electricity supply. NRG and Vistra do not currently report their operating segments along the generation and retail supply lines of business. Their business mixes in terms of operating profits in 2019 are shown in Table 14.[21] Our sample also includes AES, a diversified global energy company holding assets in both utilities and the construction and generation of electricity. However, its annual financials only disclose its business segments by geography, not by line of business.[22]

**TABLE 14: BUSINESS MIX OF NRG AND VISTRA IN 2019**

| Company [1] | Retail [2] | Generation [3] |
|---|---|---|
| NRG | 38% | 62% |
| Vistra | 8% | 92% |

21 NRG changed its segment reporting in 2020 such that the split between power generation and retail is not available.

22 AES discloses its annual financials for each of its strategic business units: US and Utilities (which covers the United States, Puerto Rico and El Salvador); South America (which covers Chile, Colombia, Argentina and Brazil); MCAC (which covers Mexico, Central America and the Caribbean); and Eurasia (which covers Europe and Asia). Source: The AES Corporation. (December 31, 2019). Form 10-K. https://s26.q4cdn.com/697131027/files/doc_financials/2019/q4/2019-Form-10-K-FINAL.pdf.

*Cost of Equity:* We estimate the return on equity (ROE) of the sample companies using the Capital Asset Pricing Model (CAPM). As shown in column [5] of Table 13, the resulting return on equity ranges from 10.8-11.2% for the companies included in the analysis. The ROE for each company is derived as the risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta." The "beta" describes each company stock's (five-year) historical correlation with the overall market, where the "market" is taken to be the S&P 500 index.

Each of these inputs is discussed below:

- We estimated the expected risk premium of the market to be 7.46% based on the long-term average of values provided by Kroll, *fka* Duff and Phelps.[23]
- In Table 13, we use a risk-free rate of 2.62%, a 15-day average of 20-year U.S. treasuries as of March 31, 2022, as the base case. In addition to our base analysis under current market conditions, we also consider the use of forecasted risk-free rates applicable five years from now to estimate the offer of a new merchant entrant that starts operating in 2026. Blue Chip Economic Indicators forecasts a 3.0% yield for 10-year Treasury yields between 2023 and 2026.[24] Adding a maturity premium (20-year bond yields over 10-year bond yields) of 0.5%, we estimate the 20-year risk-free rate to be 3.5% and use this as a sensitivity analysis, as shown in Figure 8 below.
- We use betas (column [4] in Table 13) reported by Value Line.[25] They are calculated using 2-year weekly returns.

*Cost of Debt:* In our previous analyses, we estimated the cost of debt (COD) of the sample companies by the average bond yields corresponding to the unsecured senior credit ratings for each company (issuer ratings).[26] The rating-based average yields, based on a sample of similarly-

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[23] Kroll Cost of Capital Navigator 2021, as of February 2022 (arithmetic average of excess market returns over 20-year risk-free rate from 1926-2021).

[24] Blue Chip Economic Indicators (March 2022), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers.

[25] The 3-year period is chosen over the standard 5-year period to limit the period under the new tax law, which went into effect in 2018, and also to limit the period to be post integration of the 2017 Dynegy / Vistra merger and the spinoff of NRG Yield in 2018.

[26] In Standard and Poor's (S&P) credit ratings, a company receives a higher rating based on its ability to meet financial commitments.

rated long-term (10 plus years) corporate bonds, are generally preferable than the company's actual COD, which could be more influenced by company- and issue-specific factors.[27]

TABLE 15: COST OF DEBT

| Company | S&P Credit Rating | Ratings-Based Cost of Debt | Company-Specific Cost of Debt |
|---|---|---|---|
| [1] | [2] | [3] | [4] |
| AES Corp | BBB- | 2.5% | 4.3% |
| NRG Energy Inc | BB+ | 2.8% | 4.9% |
| Vistra Corp | BB | 3.1% | 5.2% |

However, company-specific CODs could carry real-time industry-wide credit information that the typically static credit ratings for a broad swath of industries are slow to incorporate. This is the case for the merchant generation corporations: the average yields for the BBB-, BB+, and BB rated corporate bonds are barely higher than the current risk-free rate and lower than the Blue Chip forecast for the risk-free rate in 2022 and 2023. In contrast, U.S.-based IPPs' company-specific bond yields are consistently higher than the rating-based yields. Therefore, in the base-case estimation in Table 13, we use the company-specific bond yield, but in the sensitivity analysis (Figure 8 below) we also use rating-based cost of debt.

*Debt/Equity Ratio*: We estimate the five-year average debt/equity ratio for each merchant generation company using data from Bloomberg. They are reported in Table 13 above.

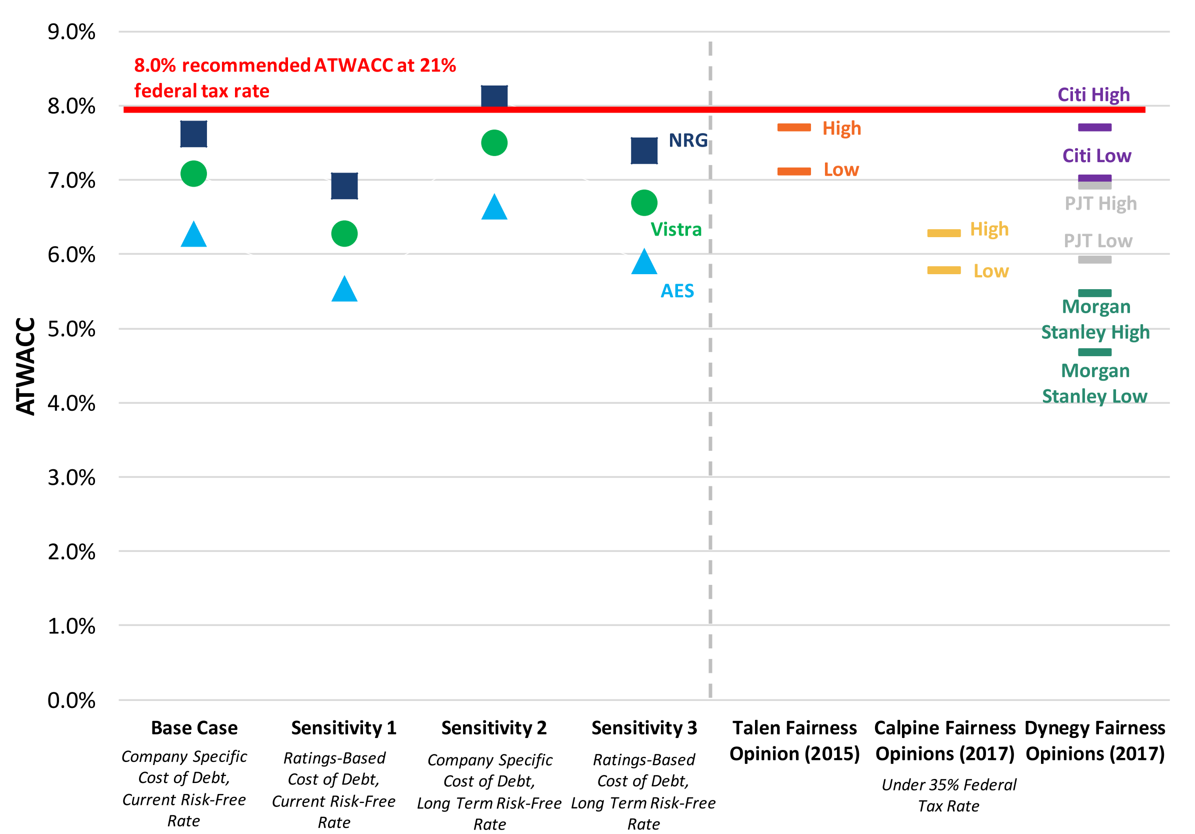
**ATWACC Sensitivities and Cost of Capital Benchmarks from Recent Fairness Opinions**:
Figure 8 reports the ATWACC for the sample under alternative assumptions for the COD and risk-free rate, along with the discount rates used in fairness opinions (discussed below) as additional reference points:

- *Baseline Case* uses the inputs and results shown in Table 13 above.
- *Sensitivity 1* uses the ratings-based COD, as used in previous PJM CONE studies.
- *Sensitivity 2* uses the forecasted long-term risk-free rate.
- *Sensitivity 3* uses both the ratings-based COD and the forecasted long-term risk-free rate.
- *Fairness Opinions* are from recent transactions (as discussed below).

[27] These idiosyncratic factors include the issuers' competitive positions within the industry, and the debt issues' seniority, callability, availability of collateral, *etc*. By construction, these factors tend to be averaged out in the ratings-based average CODs.

For the Base Case and each sensitivity, the colored marks represent each of three U.S. IPPs' ATWACCs. For example, under Sensitivity 1, the ATWACCs range from 5.5% (AES) to 6.9% (NRG). Under the other two scenarios when the forecasted risk-free rate is used, the upper ends of the ATWACC approach 8.1% (Sensitivity 2) and 7.4% (Sensitivity 3).

FIGURE 8: SUMMARY OF BASE CASE AND ALTERNATIVE CASES




Additional cost of capital reference points shown on the right side of Figure 8 above come from publicly-available discount rates used by financial advisors and analysts in valuations associated with mergers and divestitures. While there are no details provided on how these ranges were developed, these values still provide useful reference points for estimating the cost of capital. As in our 2018 analysis, we rely on three transactions with publicly-disclosed discount rates, and adjust them for the changes in the risk-free rates between the as of dates of the fairness opinions and March 31, 2022. These three transactions are

- *Acquisition of Talen Energy by Riverstone Holdings*: the disclosed range of discount rate is 6.7% to 7.3%, released in June 2016.[28] Between the fairness opinion date (March 31, 2016)

[28] Preliminary Proxy Statement, Schedule 14A, filed by Talen Energy Corporation with SEC on July 1, 2016.

and March 31, 2022, the risk-free rate increased about 0.4%. As a result, the range of 7.1% to 7.7% is shown in Figure 8.

- *Acquisition of Calpine by Energy Capital Partners*: the range of discount rate range disclosed in the June 2017 fairness opinion is 5.75% to 6.25%;[29] this is also the range shown in Figure 8, as the risk-free rates between June 2017 and March 31, 2022 are almost the same;
- *Acquisition of Dynegy by Vistra*: each of the three financial advisors (Citi for Vistra, Morgan Stanley and PJT for Dynegy) involved in that transaction used a distinct range of discount rates for evaluating the Dynegy acquisition: 4.7% to 5.5% as used by Morgan Stanley, 5.95% to 6.95% as used by PJT, and 7.0% to 7.7% as used by Citi.[30] This rather wide range of discount rates (4.7% to 7.7%) reflects the uncertainty in cost of capital estimates for the U.S. merchant generation industry. Because the risk-free rates between the fairness opinion dates and March 31, 2022 are almost the same, the originally disclosed range is shown in Figure 8.

We should note that all these acquisitions were announced before the 2018 tax law change, so their discount rates were based on the 35% federal corporate income tax rate. All else equal, the discount rate would be higher under a lower federal income tax rate. In other words, the ranges shown in Figure 8 under-estimates the ATWACC from the transactions under the current 21% tax rate.

**ATWACC for Merchant Generators in PJM Markets and the Recommended Components:** The appropriate ATWACC for the CONE study should reflect the systematic financial market risks of a merchant generating project's future cash flows from participating in the PJM wholesale power market. As a pure merchant project in PJM, the risks would be larger than for the average portfolio of independent power producers that have some long-term contracts in place.[31] As we have done in previous studies, we make an upward adjustment toward the upper end of the range from the comparable company results to reflect the relatively higher risk of pure merchant operations. Based on the set of reference points shown in Figure 8 above and the recognition of PJM merchant generation risk that exceeds the average risk of the publicly-traded generation

[29] Definitive Proxy Statement, Schedule 14A, filed by Calpine Corporation with the SEC on November 14, 2017.

[30] Definitive Proxy Statement, Schedule 14A, filed by Dynegy Inc. with the SEC on January 25, 2018.

[31] This is not to say that the reference merchant project would not arrange some medium-term financial hedging tools.

companies, we believe that an 8.0% ATWACC is the most reasonable estimate for the purpose of estimating CONE.[32]

## III.D.2. Other Financial Assumptions

Calculating CONE requires several other financial assumptions about general inflation rates, tax rates, depreciation, bonus depreciation, and interest during construction.

Income tax rates affect both the cost of capital and cash flows in the financial model used to calculate CONE. We calculated income tax rates based on current federal tax rates of 21%. The state tax rates assumed for each CONE Area are shown in Table 16.

**TABLE 16: STATE CORPORATE INCOME TAX RATES**

| CONE Area | Representative State | Corporate Income Tax Rate |
|---|---|---|
| 1 Eastern MAAC | New Jersey | 11.50% |
| 2 Southwest MAAC | Maryland | 8.25% |
| 3 Rest of RTO | Pennsylvania | 9.99% |
| 4 Western MAAC | Pennsylvania | 9.99% |

*Sources and notes:* State tax rates retrieved from www.taxfoundation.org. Machinery and equipment for electricity generation are exempt from state sales taxes.

We calculated depreciation for the 2026/27 CONE parameter based on the bonus depreciation provisions of the 2017 Tax Cuts and Jobs Act. New units put in service before January 1, 2027 can apply 20% bonus depreciation in the first year of service, which decreases CC CONE on average by $10/MW-day relative to no bonus depreciation. The bonus depreciation phases out completely by the following year. Similar to the 2018 PJM CONE study, we apply the Modified Accelerated Cost Recovery System (MACRS) of 20 years for the reference CC to the remaining depreciable costs (*i.e.*, 20% bonus depreciation, 80% MACRS in 2026/27).[33]

To calculate the annual value of depreciation, the "depreciable costs" (different from the overnight and installed costs referred to earlier in the report) for a new resource are the sum of

[32] The weighted average cost of capital (WACC) without considering the tax advantage of debt payments is 8.0%. We report this value because it is comparable to values reported in other recently released CONE studies in ISO-NE and NYISO.

[33] Internal Revenue Service (2021), *Publication 946, How to Depreciate Property,* March 3, 2022. Available at http://www.irs.gov/pub/irs-pdf/p946.pdf.

the depreciable overnight capital costs and the accumulated interest during construction (IDC). Several capital cost line items are non-depreciable, including fuel inventories and working capital, and have not been included in the depreciable costs. IDC is calculated based on the assumption that the construction capital structure is the same as the overall project, *i.e.*, 55% debt and 4.7% COD.

## III.E. Economic Life and Levelization Approach

Translating investment costs into annualized costs for the purpose of setting annual capacity price benchmarks requires an assumption about how net revenues are received over an assumed economic life, such that the investor recovers capital and annual fixed costs.

For economic life, we recommend continuing the prior assumption of a 20-year economic life. Although new natural gas-fired plants can physically operate for 30 years or longer, developers in the stakeholder community expressed doubt in any value beyond 20 years in the current and projected policy environment. The policy environment is increasingly disfavoring generation resources that emit greenhouse gases. For example, Illinois and New Jersey have passed legislation or are considering regulations to limit the operation of natural gas-fired plants.[34]

We continue to assume "level-nominal" cost recovery with net revenues constant in nominal terms (*i.e.*, decreasing in real, inflation-adjusted dollar terms), based on our prior analysis of the drivers of long-term cost recovery and updated analysis of the long-term trends in gas turbine costs. Clearly, assuming such a steady stream of revenues then terminating them after an assumed 20-year life is a simplification. Our concurrent VRR Report tests the robustness of the recommended VRR curve to an uncertainty range that encompasses different assumptions on cost recovery.

[34] In Illinois, the 2021 Climate and Equitable Jobs Act (CEJA) phases out of privately-owned gas generation by 2045. While the CEJA does not limit the ability of new CCs to enter, alternative ownership structures may be required with public entities to maintain operation over a 20-year economic life. In New Jersey, the Department of Environmental Protection proposed rules in 2021 that would limit $CO_2$ emissions for new gas generation units to below 860 lbs $CO_2$/MWh starting in 2025. Despite this proposed rule, the reference CC will be able to meet the emissions requirements.

# III.F. CONE Results and Comparisons

## III.F.1. Summary of CONE Estimates

The administrative Gross CONE value reflects the total annual net revenues a new generation resource needs to earn on average to recover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 17 summarizes our plant capital costs, annual fixed costs, and levelized CONE estimates for the CC reference plants for the 2026/27 delivery year. The level-nominal CONE estimates range from $506/MW-day in WMAAC to $490/MW-day in SWMAAC.

**TABLE 17: ESTIMATED CONE FOR CC PLANTS IN 2026/27**

| | | | | 1 x 1 Combined Cycle | | | |
|---|---|---|---|---|---|---|---|
| | | | | EMAAC | SWMAAC | Rest of RTO | WMAAC |
| | **Gross Costs** | | | | | | |
| [1] | Overnight | *$m* | | $1,359 | $1,240 | $1,263 | $1,308 |
| [2] | Installed (inc. IDC) | *$m* | | $1,470 | $1,343 | $1,367 | $1,415 |
| [3] | First Year FOM | *$m/yr* | | $37 | $53 | $47 | $39 |
| [4] | **Net Summer ICAP** | ***MW*** | | **1,171** | **1,174** | **1,144** | **1,133** |
| | **Unitized Costs** | | | | | | |
| [5] | Overnight | *$/kW* | = [1] / [4] | $1,160 | $1,057 | $1,104 | $1,154 |
| [6] | Installed (inc. IDC) | *$/kW* | = [2] / [4] | $1,255 | $1,144 | $1,195 | $1,248 |
| [7] | Levelized FOM | *$/kW-yr* | | $39 | $49 | $47 | $42 |
| [8] | **After-Tax WACC** | ***%*** | | **7.9%** | **8.0%** | **8.0%** | **8.0%** |
| [9] | Effective Charge Rate | *%* | | 12.4% | 12.2% | 12.3% | 12.3% |
| [10] | **Levelized CONE** | ***$/MW-yr*** | = [5] x [9] + [7] | **$182,700** | **$178,700** | **$183,100** | **$184,500** |
| [11] | **Levelized CONE** | ***$/MW-day*** | = [10] / 365 | **$501** | **$490** | **$502** | **$506** |

*Sources and notes:* CONE values expressed in 2026 dollars and ICAP terms.

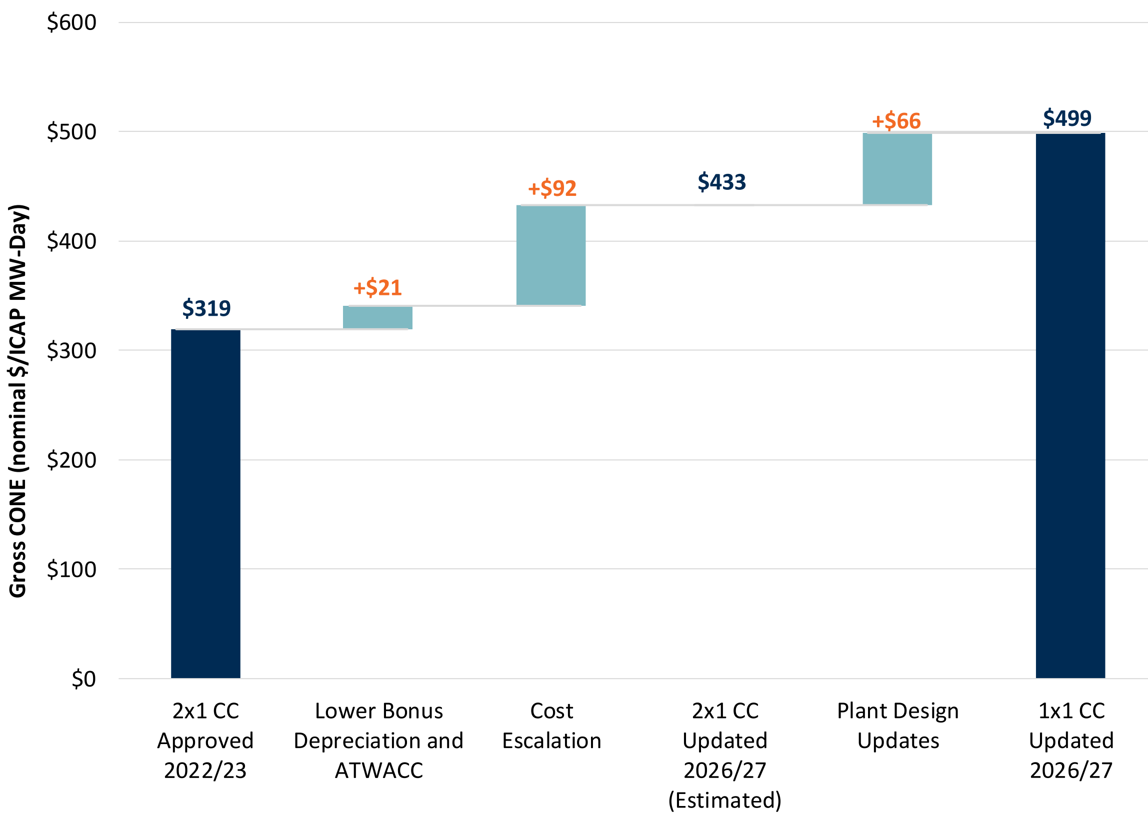
The CC CONE estimates vary slightly by CONE Area, primarily due to differences in labor rates (highest in EMAAC), firm gas contracts (highest in Rest of RTO), total income tax rates (highest in Rest of RTO and WMAAC), and property taxes (highest in SWMAAC).

## III.F.2. Comparison to Prior CONE Estimates

The 2026/27 CC CONE estimates are considerably higher than the values derived from the 2018 Study that were used (as MOPR parameters) in PJM's Base Residual Auction for the 2022/23

Delivery Year as shown in Figure 9. To explain those increases in terms of individual drivers, we sequentially estimated the impact of changes in bonus depreciation and ATWACC, then cost escalation, and finally, plant design updates.

**FIGURE 9: DRIVERS OF HIGHER CC 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)**




The drivers for higher CONE are explained below:

- Bonus Depreciation and ATWACC: The temporary 100% bonus depreciation included in the 2022/23 CONE value decreases to 20% by 2026, increasing CONE by $25/MW-Day (ICAP).[35] The ATWACC decreased from 8.2% in the prior CONE value to 8.0% currently, decreasing CONE by $4/MW-Day (ICAP), for a net effect of $21/MW-Day (ICAP).
- Cost Escalation: Since the development of the 2022/23 CONE value in our 2018 Study (based on overnight costs of a plant built in 2017), the costs of materials, equipment, and labor costs have escalated along with generalized inflation at a faster rate than expected. For example, from December 2017 to December 2021, material costs increased by 36% compared to

[35] 115th United State Congress, "Tax Cuts and Jobs Act," Signed into law December 22, 2017

expectations of only 10%.[36] With that unexpected escalation over that time period, plus projected escalation to a 2026 installation, total cost escalation to 2026/27 adds $92/MW-Day (ICAP) to the 2x1 CC 2022/23 CONE value.

- Plant Design Updates: The use of dry-cooling ACCs, firm gas transportation contracts (and to a small degree the switch from a 2x2 CC to a double-train 1x1 CCs) as discussed in Section III.A above, adds $66/MW-Day (ICAP) to the 2x1 CC Updated 2026/27 (Estimated) CONE.

# III.G. Annual CONE Updates

The PJM tariff specifies that prior to each auction PJM will escalate CONE for each year between the CONE studies during the RPM Quadrennial Review. The updates will account for changes in plant capital costs based on a composite of Department of Commerce's Bureau of Labor Statistic indices for labor, turbines, and materials.

We recommend that PJM continue to update the CONE value prior to each auction using this approach with slight adjustments to the index weightings based on the updated capital cost estimates. As shown in Table 18 below, we recommend that PJM re-weight the components to account for the increasing portion of total plant costs that are from the costs of labor. For the CC, PJM should calculate the composite index based on 40% labor, 45% materials, and 15% turbine. For the CT, PJM should calculate the composite index based on 30% labor, 45% materials, and 25% turbine.

**TABLE 18: CONE ANNUAL UPDATE COMPOSITE INDEX**

| | **Combustion Turbine** | | | **Combined Cycle** | | |
|---|---|---|---|---|---|---|
| Component | PJM Tariff Composite Index | CONE Study Capital Cost Weightings | Recommended Composite Index | PJM Tariff Composite Index | CONE Study Capital Cost Weightings | Recommended Composite Index |
| Labor | 20% | 30% | 30% | 25% | 43% | 40% |
| Materials | 50% | 45% | 45% | 60% | 45% | 45% |
| Turbine | 30% | 25% | 25% | 15% | 12% | 15% |

PJM will need to account for bonus depreciation declining from 20% for the 2026/2027 BRA to 0% in the 2027/2028 BRA and subsequent auctions. We calculate that a reduction in the bonus depreciation by 20% increases the CT CONE by 1.7% and the CC CONE by 2.1% due to the decreasing depreciation tax shield. We recommend just for the 2027/2028 BRA that after PJM

[36] Material and turbine costs increases are based on BLS Producer Price Index for *Construction Materials* and *Components for Construction* and *Turbines and Turbine Generator Sets* between December 2017 and December 2021. Values may not add to 100% due to rounding.

has escalated CONE by the composite index, as noted above, PJM account for the declining tax advantages of no longer receiving bonus depreciation by applying an additional gross up of 1.017 for CT and 1.021 for CCs. For subsequent auctions, no further gross up will be necessary.

## III.H. E&AS Offset Methodology

The VRR Curve prices are indexed to Net CONE, which is derived by subtracting the reference resource's net energy and ancillary service (E&AS) revenues from its Gross CONE. This E&AS offset could be estimated in a variety of ways. PJM originally estimated it based on actual historical electricity and natural gas prices over the past 3 years. In 2020, PJM adopted a forward-looking approach to calculating the E&AS offset based on forward prices for electricity and natural gas, with hourly shapes based on historical data. FERC subsequently ordered PJM in December 2021 to revert back to the historical method because the forward methodology had been implemented along with PJM's proposed Reserve Pricing Reforms that FERC eventually rejected.

We continue to recommend calculating E&AS on a forward basis over a historical approach. As discussed in our prior reviews, the forward E&AS offset is superior because it reflects expected market conditions that developers will face upon entry into the market. The methodology we helped PJM develop is analytically rigorous, based on forward market data for electricity and natural gas. It is similar to approaches we have implemented for clients and have seen other investors use to estimate their future net E&AS revenues (and, by extension, to estimate how much they would need to earn from the capacity market to enter). By contrast, the backward looking approach reflects past conditions that may be unrepresentative and irrelevant to the future investments that RPM is supposed to attract (with a willingness-to-pay indexed to estimated Net CONE). Not only are past prices reflective of outdated fundamentals regarding demand, supply, fuel prices, and transmission; worse, they may include anomalous weather conditions that substantially distort the calculation and make it unduly volatile.[37]

However, both historical and forward methods rely on market prices that recently have reflected installed capacity well above the reserve requirement, which can perpetuate disequilibria. When supply is scarce, for example, the E&AS offset will increase and scale down the VRR curve thus

[37] For the same reasons, we recommend forward E&AS offsets for "Net ACR" based offer caps in its market power mitigation, which PJM could consider in its upcoming broader review of RPM. However, even if this is not implemented, we still recommend using a forward E&AS for the VRR curve to reflect expected forward market conditions. The VRR is designed to support new entry until the target reserve margin is met, with developers expecting to just earn CONE from the combination of capacity and expected E&AS revenues.

buy less capacity just when it is needed. This could be avoided by adjusting the E&AS offset to what they would be at the target reserve margin, as NYISO and ISO-NE attempt to do. However, the need for an adjustment is not necessarily clear, without knowing what beliefs about reserve margins underlie forward market prices. Any equilibrium E&AS offset would rely on market simulations, which tend not to be transparent and are difficult to fully calibrate to produce realistic market prices.

Assuming PJM pursues a forward approach again, we reviewed several aspects of its approach and provide the following recommendation:

- Electric Hub Mapping: Maintain current mapping of electricity futures hubs to zones, as the mapping is supported by recent prices;
- Natural Gas Hub Mapping: Switch EKPC gas hub from Columbia-App TCO to MichCon; otherwise current gas hub mapping supported by recent prices;
- Ancillary Service Prices: Remove regulation revenues from the calculation of the E&AS offset and scale historical hourly sync and non-sync reserve prices by forward energy prices.

Regarding ancillary services, we determined that regulation revenues should not be included in the calculation because the market is too small at only 500-800 MW (some of which is already absorbed by BESS plants providing the premium RegD product). By contrast, the capacity market has to be able to attract thousands of MW as needed if retirements and load growth occur. Such large amounts of new entrants could not earn major revenues from the small market. If the revenues per plant were high, the first few plants would use up that opportunity quickly; if the revenues were low, accounting for them (versus selling more energy) would not change the Net CONE estimate.

PJM also requested that we review the approach for calculating the energy efficiency wholesale energy savings to determine whether the utility EE programs included in the analysis continue to be reasonable. Based on our review of the available public data on EE programs, we recommend maintaining the sample of utilities included in the current Net CONE analysis (ComEd, BG&E, and PPL), but updating the inputs based on the most recent program costs and impacts. The current sample includes the largest utilities in each state that provides sufficient detail for the analysis. Our review of public program-level data for EE programs across PJM did not identify any additional utility-run programs with similar level of detail to include them in the sample.

# III.I. Implications for Net CONE

## III.I.1. Indicative E&AS Offsets

The application of the E&AS offset methodology in Section III.H results in an updated E&AS due to a reduced ramp rate, the removal of transportation costs, removal of regulation revenue, and updates to other operating characteristics associated with the technical specifications for the CC.[38] Table 19 shows the effect of each of these changes on the forward-looking 2023/24 E&AS revenue offset by zone for the CC based on simulations provided by PJM staff.

[38] Other parameter updates include updated operating characteristics associated with the most recent turbine models, the addition of dry-cooling, and the 1x1 single shaft CC configuration.

TABLE 19: UPDATED 2023/24 CC E&AS REVENUE OFFSET BY ZONE ($/MW-DAY ICAP)

| *All values in nominal $/MW-day ICAP* | CC | | | |
|---|---|---|---|---|
| | Current 2023/24 EAS | Updated Operating Costs | Removed Regulation | Updated 2023/24 EAS |
| **CONE Area 1** | | | | |
| AECO | $168 | $2 | -$24 | $146 |
| DPL | $216 | $3 | -$23 | $196 |
| JCPL | $166 | $2 | -$24 | $143 |
| PECO | $184 | $14 | -$23 | $174 |
| PSEG | $162 | $2 | -$24 | $140 |
| RECO | $172 | $2 | -$23 | $151 |
| **CONE Area 2** | | | | |
| BGE | $254 | $4 | -$20 | $239 |
| PEPCO | $197 | $10 | -$21 | $185 |
| **CONE Area 4** | | | | |
| METED | $212 | $15 | -$22 | $205 |
| PENELEC | $320 | $7 | -$17 | $310 |
| PPL | $190 | $15 | -$22 | $182 |
| **CONE Area 3** | | | | |
| AEP | $242 | $8 | -$21 | $229 |
| APS | $281 | $5 | -$19 | $267 |
| ATSI | $208 | $44 | -$21 | $231 |
| COMED | $179 | $11 | -$22 | $168 |
| DAY | $223 | $45 | -$21 | $247 |
| DEOK | $214 | $43 | -$21 | $237 |
| DUQ | $225 | $15 | -$20 | $219 |
| DOM | $195 | $9 | -$21 | $183 |
| EKPC | $246 | $14 | -$21 | $239 |
| **RTO** | **$189** | **$11** | **-$23** | **$177** |

Note: The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020. The "Updated 2023/24 EAS" values do not reflect changes to scaling historical hourly sync and non-sync reserve prices by forward energy prices, nor updating gas prices in EKPC's zone.

## III.I.2. Indicative Net CONE

Net CONE is the estimated annualized fixed costs of new entry, or Gross CONE, of the reference resource, net of estimated E&AS margins and expected performance bonus. PJM calculates the Net CONE by subtracting the net energy and ancillary service (E&AS) revenues from the Gross CONE. We present in Table 20 below indicative CC Net CONE estimates for all LDAs relative to the parameters used in the 2022/23 MOPR (adjusted here to differentiate CONE values by area).

We say "indicative" because the scope of our assignment includes estimating Gross CONE values and recommending changes to the E&AS approach, but does not include estimating the E&AS offsets for the 2026/27 BRA.

**TABLE 20: INDICATIVE CC NET CONE ($/MW-DAY UCAP)**

| *All values in nominal $/MW-day UCAP* | CC 2022/23 MOPR | | | CC 2026/27 Brattle Estimate | | |
|---|---|---|---|---|---|---|
| | CONE | EAS | Net CONE | CONE | EAS | Net CONE |
| **CONE Area 1** | | | | | | |
| AECO | $335 | $167 | $163 | $517 | $174 | $343 |
| DPL | $335 | $208 | $122 | $517 | $231 | $286 |
| JCPL | $335 | $165 | $165 | $517 | $172 | $346 |
| PECO | $335 | $186 | $144 | $517 | $206 | $311 |
| PSEG | $335 | $161 | $169 | $517 | $168 | $349 |
| RECO | $335 | $171 | $159 | $517 | $180 | $337 |
| **EMAAC** | **$335** | **$181** | **$154** | **$517** | **$189** | **$329** |
| **CONE Area 2** | | | | | | |
| BGE | $345 | $254 | $76 | $506 | $279 | $227 |
| PEPCO | $345 | $191 | $139 | $506 | $219 | $287 |
| **SWMAAC** | **$345** | **$238** | **$107** | **$506** | **$249** | **$257** |
| **CONE Area 4** | | | | | | |
| METED | $323 | $207 | $123 | $522 | $241 | $281 |
| PENELEC | $323 | $306 | $24 | $522 | $359 | $163 |
| PPL | $323 | $185 | $145 | $522 | $216 | $307 |
| **MAAC** | **$334** | **$204** | **$130** | **$517** | **$222** | **$294** |
| **CONE Area 3** | | | | | | |
| AEP | $316 | $233 | $97 | $518 | $268 | $251 |
| APS | $316 | $272 | $58 | $518 | $311 | $208 |
| ATSI | $316 | $224 | $106 | $518 | $271 | $248 |
| COMED | $316 | $195 | $135 | $518 | $199 | $319 |
| DAY | $316 | $235 | $95 | $518 | $288 | $230 |
| DEOK | $316 | $224 | $106 | $518 | $277 | $242 |
| DUQ | $316 | $223 | $107 | $518 | $257 | $261 |
| DOM | $316 | $181 | $149 | $518 | $216 | $303 |
| EKPC | $316 | $232 | $98 | $518 | $279 | $239 |
| OVEC | $316 | $260 | $70 | $518 | $303 | $216 |
| **RTO** | **$330** | **$185** | **$146** | **$516** | **$209** | **$307** |

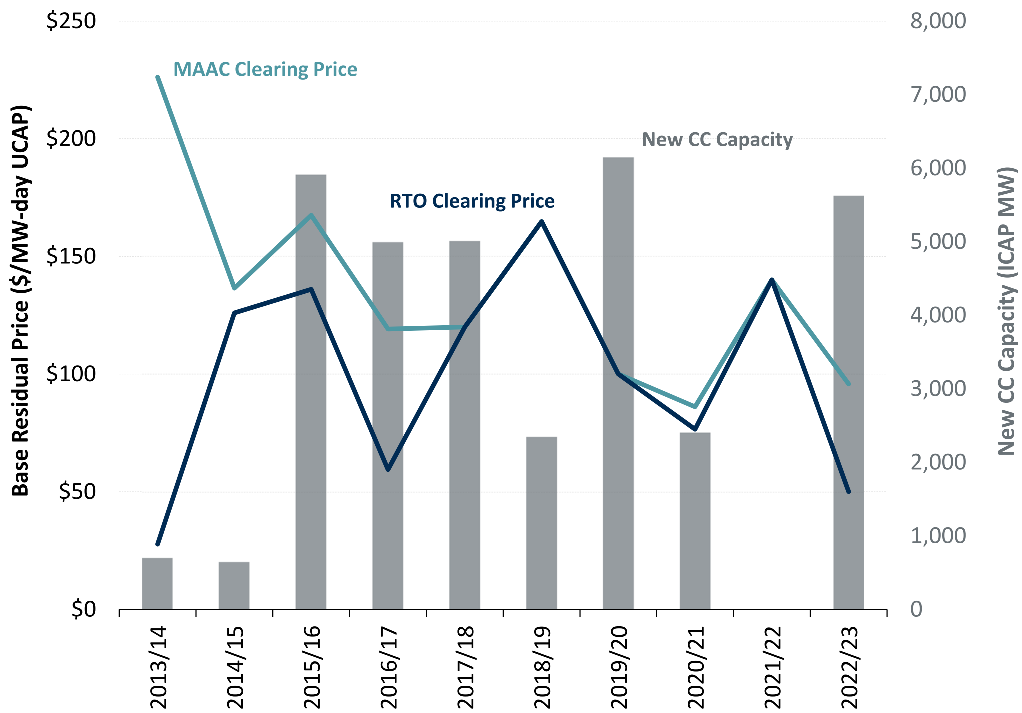
Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

Net CONE is $257–$329/MW-Day (UCAP) across all parent LDAs. Compared to the 2022/23 BRA, the Net CONE roughly doubled for all parent LDAs. Increases in Net CONE are due to the increases in Gross CONE described in Section III.F (cost escalation, decreases in bonus depreciation, and plant design changes) with a slight offset from higher E&AS values. The differences among modeled LDAs and the RTO are similar to the prior.

## III.I.3. Comparison to "Empirical Net CONE"

Another informative comparison is to the prices at which actual CCs have been willing to enter the market in past capacity auctions (sometimes referred to as "empirical Net CONE"). Those prices ranged from $75 to $165/MW-Day UCAP in most of the recent auctions, as shown in Figure 10 below. Note that 2022/23 prices should be disregarded as an indicator of willingness to enter since the compressed forward period for that auction meant that new entrants' decisions were already made by the time the auction occurred.

FIGURE 10: HISTORICAL BRA CAPACITY PRICES AND NEW CC CAPACITY




*Sources and notes:* PJM Base Residual Auction Reports and Planning Parameters. See PJM BRA results 2013/14-2022/23. Please note that the 2022/23 BRA was a compressed auction.

Empirical Net CONE is not a perfect indicator of "true Net CONE" at which capacity could enter at scale—even at the time that capacity entered—because of variability across locations, limited entry in any single auction, and observing only a single clearing price. Some entrants would have entered at prices below the clearing price, whereas uncleared projects, which might have been needed if more retirements or load growth had occurred, would require a higher price. Some may be willing to enter the market at low prices because of their idiosyncratic advantages that cannot be replicated at scale. For example, some past entrants may have enjoyed special opportunities to access natural gas at anomalously low costs earlier in the development of the

Marcellus Shale and export pipelines. Despite these limitations, empirical Net CONE is still a useful benchmark.

Extrapolating backward-looking empirical Net CONE to the future, however, must consider how costs and market conditions have changed. As discussed above, the true cost of entry is in fact increasing due to cost escalation, changes in environmental regulations and plant configurations, and tax laws—by $180/MW-day in our estimation compared to a few years ago. In addition, since the long-term prospects for cash flows have diminished with the industry's transition toward clean energy, entrants may need to front-load their revenues more so than in the past. For example, if they used to assume a 30-year economic life but now assume 20 years, that would further increase Net CONE by $44/MW-day ICAP. Altogether, adding that $180 + $44 to historical empirical Net CONE of $100-165/MW-day, suggests an adjusted benchmark for 2026 of as much as $324-389/MW-day, or $280-345 MW-day without the adjustment for economic life. This is not far from our estimated Net CONE of $257-$329/MW-day across modeled LDAs.

## III.I.4. Uncertainty Analysis

There is considerable uncertainty in estimating Net CONE. Most of the uncertainty surrounds volatile inflation, relevant technologies and plant designs, and the analyst's judgment on economic life and long-term cost recovery. For example, a less constrained plant design with dual fuel and cooling towers could cost as much as $87/MW-day less; or a shorter 15-year economic life could add $52/MW-day, or more if technologies are more constrained by environmental regulations. These examples indicate an uncertainty range on Net CONE of -29% to +16%; the full uncertainty range may be greater when considering uncertainties beyond those we analyzed. In that context, the VRR curve must be steeper to perform well even if Net CONE is mis-estimated, and we recommend testing robustness under stress tests of +/-40%, as discussed in our parallel VRR Curve report.

# IV. Natural Gas-Fired Combustion Turbines

## IV.A. Technical Specifications

We used a similar approach discussed in Section III.A as the reference CC to determine the technical specifications for the reference CT. The technical specifications for the reference CT shown in Table 21 are based on the assumptions discussed later in this section.

**TABLE 21: CT REFERENCE RESOURCE TECHNICAL SPECIFICATIONS**

| **Plant Characteristic** | **Specification** |
|---|---|
| **Turbine Model** | GE 7HA.02 60HZ |
| **Configuration** | 1 x 0 |
| **Cooling System** | n/a |
| **Power Augmentation** | Evaporative Cooling; no inlet chillers |
| **Net Summer ICAP (MW)** | 361 / 363 / 353 / 350* |
| **Net Heat Rate (HHV in Btu/kWh)** | 9320 / 9317 / 9304 / 9311* |
| **Environmental Controls** | |
| CO Catalyst | Yes |
| Selective Catalytic Reduction | Yes |
| **Dual Fuel Capability** | No |
| **Firm Gas Contract** | Yes |
| **Special Structural Requirements** | No |
| **Blackstart Capability** | None |
| **On-Site Gas Compression** | None |

Sources and notes: See Table 3 for ambient conditions assumed for calculating net summer installed capacity (ICAP) and net heat rate.
* For EMAAC, SWMAAC, Rest of RTO, and WMAAC, respectively.

For the reference CT, there has been very limited development of frame-type CTs in PJM since 2011, as shown in Table 22, to support a specific turbine model. While aeroderivative-type turbines such as the GE LM6000 have been the most common since 2011, they have higher Net CONE than 7HA turbines. The 7HA turbine is the current model assumed for the PJM reference resource, it is the most built turbine for CCs, and the IMM has used the same turbine for its evaluation of Net Revenues in the annual State of the Market report since 2014. For these reasons, the frame-type GE 7HA turbine is a reasonable choice for the CT in PJM. Due to the larger size of the 7HA turbine, we assume that the reference CT plant includes only a single turbine ("1×0" configuration). The majority of the specifications have remained the same as the 2018 CONE Study.

**TABLE 22: TURBINE MODEL OF CT PLANTS BUILT OR UNDER CONSTRUCTION IN PJM AND THE U.S. SINCE 2011**

| Turbine Model | Turbine Class | PJM | | US | |
|---|---|---|---|---|---|
| | | *(count)* | *(MW)* | *(count)* | *(MW)* |
| General Electric LM6000 | Aeroderivative | 7 | 331 | 69 | 3,101 |
| General Electric 7FA | Frame | 2 | 330 | 14 | 2,462 |
| Pratt & Whitney FT4000 | Aeroderivative | 2 | 120 | 2 | 120 |
| Rolls Royce Corp Trent 60 | Aeroderivative | 2 | 119 | 2 | 119 |
| Pratt & Whitney FT8 | Aeroderivative | 1 | 57 | 4 | 189 |
| Siemens Unknown | N.A. | 1 | 28 | 2 | 545 |
| General Electric LMS100 | Aeroderivative | 0 | 0 | 47 | 4,664 |
| Siemens SGT6-5000F | Frame | 0 | 0 | 10 | 1,892 |
| Rolls Royce Corp Unknown | N.A. | 0 | 0 | 10 | 599 |
| General Electric 7EA | Small Frame | 0 | 0 | 7 | 417 |
| Siemens AG SGT | Frame | 0 | 0 | 7 | 401 |
| General Electric 7HA | Frame | 0 | 0 | 1 | 330 |
| *All Other Turbine Models* | | 0 | 0 | 14 | 1,297 |
| **Total** | | **15** | **985** | **189** | **16,136** |

Sources and notes: Data downloaded from ABB Inc.'s Energy Velocity Suite August 2021.

## IV.B. Capital Costs

For the CT, we relied on a similar approach for estimating capital costs that are specified for the reference CC in Section III.B with a few exceptions. The following assumptions differ for estimating the capital costs for the CT:

- Emission Reduction Credits: Similar to the 2018 CONE Study, we assumed the CT would not be required to purchase ERCs because they are not projected to exceed the new source review (NSR) threshold. This assumption is supported by the run-time operational limit that the Perryman Unit 6 CT plant built in 2015 in Maryland included in its operating permit to avoid exceeding emissions thresholds.[39]

- Land: Similar to the reference CC, we estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county.  shows the resulting land prices we assumed for each CONE Area and the final estimated cost for the land in each location.  We assume that 10 acres of land are for the reference CT.

**TABLE 23: COST OF LAND PURCHASED FOR REFERENCE CT**

| CONE Area | Land Price *($/acre)* | Plot Size Gas CT *(acres)* | Cost Gas CT *($m)* |
|---|---|---|---|
| 1 EMAAC | $36,600 | 10 | $0.37 |
| 2 SWMAAC | $29,500 | 10 | $0.30 |
| 3 Rest of RTO | $16,400 | 10 | $0.16 |
| 4 WMAAC | $30,600 | 10 | $0.31 |

Sources and notes:  We assume land is purchased in 2022, i.e., 6 months to 1 year before the start of construction.

Based on the technical specifications for the CT described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 24 below.

[39] The Perryman Unit 6 operating permit is available here: https://mde.maryland.gov/programs/Permits/AirManagementPermits/Test/Constellation%20Perryman%20Renewal%20Title%20V%202018.pdf

### TABLE 24: PLANT CAPITAL COSTS FOR CT REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE

| | CONE Area | | | |
|---|---|---|---|---|
| | 1 | 2 | 3 | 4 |
| | EMAAC | SWMAAC | Rest of RTO | WMAAC |
| **Capital Costs (in $millions)** | *361 MW* | *363 MW* | *353 MW* | *350 MW* |
| **Owner Furnished Equipment** | | | | |
| Gas Turbines | $78.6 | $78.6 | $78.6 | $78.6 |
| HRSG / SCR | $33.5 | $33.5 | $33.5 | $33.5 |
| Sales Tax | $0.0 | $0.0 | $0.0 | $0.0 |
| **Total Owner Furnished Equipment** | **$112.1** | **$112.1** | **$112.1** | **$112.1** |
| **EPC Costs** | | | | |
| Equipment | | | | |
| Other Equipment | $24.1 | $24.1 | $24.1 | $24.1 |
| Construction Labor | $50.6 | $37.8 | $40.6 | $45.0 |
| Other Labor | $16.4 | $15.4 | $15.6 | $16.0 |
| Materials | $8.1 | $8.1 | $8.1 | $8.1 |
| Sales Tax | $0.0 | $0.0 | $0.0 | $0.0 |
| EPC Contractor Fee | $21.1 | $19.8 | $20.1 | $20.5 |
| EPC Contingency | $23.2 | $21.7 | $22.1 | $22.6 |
| **Total EPC Costs** | **$143.6** | **$127.0** | **$130.6** | **$136.3** |
| **Non-EPC Costs** | | | | |
| Project Development | $12.8 | $12.0 | $12.1 | $12.4 |
| Mobilization and Start-Up | $2.6 | $2.4 | $2.4 | $2.5 |
| Net Start-Up Fuel Costs | -$0.6 | -$0.6 | $0.1 | -$0.5 |
| Electrical Interconnection | $7.8 | $7.8 | $7.6 | $7.6 |
| Gas Interconnection | $33.7 | $33.7 | $33.7 | $33.7 |
| Land | $0.4 | $0.3 | $0.2 | $0.3 |
| Fuel Inventories | $0.0 | $0.0 | $0.0 | $0.0 |
| Non-Fuel Inventories | $1.3 | $1.2 | $1.2 | $1.2 |
| Owner's Contingency | $4.6 | $4.6 | $4.6 | $4.6 |
| Emission Reduction Credit | $0.0 | $0.0 | $0.0 | $0.0 |
| Financing Fees | $7.0 | $6.6 | $6.7 | $6.8 |
| **Total Non-EPC Costs** | **$69.6** | **$68.0** | **$68.7** | **$68.6** |
| **Total Capital Costs** | **$325.3** | **$307.1** | **$311.4** | **$317.0** |
| **Overnight Capital Costs ($million)** | **$325** | **$307** | **$311** | **$317** |
| **Overnight Capital Costs ($/kW)** | **$902** | **$846** | **$882** | **$906** |
| **Installed Cost ($/kW)** | **$945** | **$887** | **$925** | **$949** |

### IV.B.1. Escalation to 2026 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period of 20 months for CTs.[40] We escalated the 2021 estimates of overnight capital cost components forward to the construction period for a June 2026 online date using the nominal cost escalation rates presented in Table 8. We maintained the same escalation approach for Land, Net Start-up Fuel and Fuel Inventories, and Electric and Gas Interconnection as the CC

## IV.C. Operations and Maintenance Costs

Table 25 summarizes the fixed and variable O&M for CTs with an online date of June 1, 2026. Additional details on Plant Operation and Maintenance, Insurance and Asset Management Costs, Property Taxes, Working Capital, and Firm Transportation Service Contracts can be found in the above Section III.C.2. Details on Variable O&M costs can be found in Section III.C.3. With their lower expected capacity factor, the CTs are assumed to undergo major maintenance cycles tied to the factored starts of the unit, as opposed to the factored fired hours maintenance cycles of the CCs. For this reason, the major maintenance cost component for the CTs is reported in "$/factored start" and not the $/MWh used for other consumables. We escalated the components of the O&M cost estimates from 2021 to 2026 on the basis of cost escalation indices particular to each cost category, same as the reference CC, using the real escalation rates shown in Table 8 to escalate the O&M costs.

[40] The construction drawdown schedule occurs over 20 months with 84% of the costs incurred in the final 11 months prior to commercial operation.

TABLE 25: O&M COSTS FOR CT REFERENCE RESOURCE

| O&M Costs | CONE Area<br>1<br>EMAAC<br>*361 MW* | <br>2<br>SWMAAC<br>*363 MW* | <br>3<br>Rest of RTO<br>*353 MW* | <br>4<br>WMAAC<br>*350 MW* |
|---|---|---|---|---|
| **Fixed O&M (2026$ million)** | | | | |
| LTSA Fixed Payments | $0.3 | $0.3 | $0.3 | $0.3 |
| Labor | $1.2 | $1.2 | $0.9 | $0.9 |
| Maintenance and Minor Repairs | $0.5 | $0.5 | $0.5 | $0.5 |
| Administrative and General | $0.2 | $0.3 | $0.2 | $0.2 |
| Asset Management | $0.5 | $0.6 | $0.4 | $0.4 |
| Property Taxes | $0.3 | $4.1 | $2.2 | $0.3 |
| Insurance | $2.0 | $1.8 | $1.9 | $1.9 |
| Firm Gas Contract | $4.4 | $5.4 | $7.1 | $6.3 |
| Working Capital | $0.0 | $0.0 | $0.0 | $0.0 |
| **Total Fixed O&M (2026$ million)** | **$9.5** | **$14.4** | **$13.5** | **$10.9** |
| **Levelized Fixed O&M (2026$/MW-yr)** | **$26,300** | **$39,600** | **$38,300** | **$31,300** |
| **Variable O&M (2026$/MWh)** | | | | |
| Consumables, Waste Disposal, Other VOM | 1.19 | 1.18 | 1.15 | 1.22 |
| **Total Variable O&M (2026$/MWh)** | **1.19** | **1.18** | **1.15** | **1.22** |
| *Major Maintenance - Starts Based ($/factored start, per turbine)* | **21,170** | **21,170** | **21,170** | **21,170** |

# IV.D.CONE Results and Comparisons

Table 26 shows plant capital costs, annual fixed costs, and levelized CONE estimates for the CT reference plant for the 2026/27 delivery year. CONE estimates range from $378/MW-day in EMAAC to $403/MW-day in the Rest of RTO. Note that we assumed accelerated tax depreciation based on the 15-year MACRS for the CT to the depreciable costs after accounting for bonus depreciation.

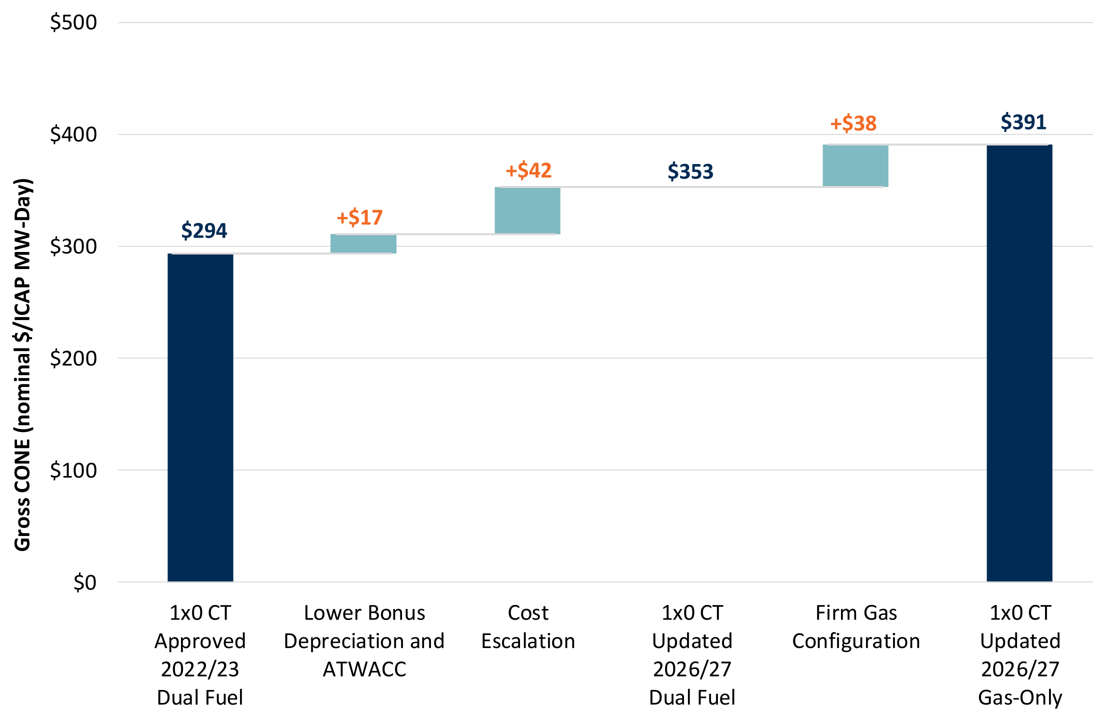
#### TABLE 26: ESTIMATED CONE FOR CT PLANTS FOR 2026/27 IN 2026$ AND ICAP MW

| | | | | Simple Cycle | | | |
|---|---|---|---|---|---|---|---|
| | | | | EMAAC | SWMAAC | Rest of RTO | WMAAC |
| | **Gross Costs** | | | | | | |
| [1] | Overnight | *$m* | | $325 | $307 | $311 | $317 |
| [2] | Installed (inc. IDC) | *$m* | | $341 | $322 | $326 | $332 |
| [3] | First Year FOM | *$m/yr* | | $9 | $14 | $14 | $11 |
| [4] | **Net Summer ICAP** | ***MW*** | | **361** | **363** | **353** | **350** |
| | **Unitized Costs** | | | | | | |
| [5] | Overnight | *$/kW* | = [1] / [4] | $902 | $846 | $882 | $906 |
| [6] | Installed (inc. IDC) | *$/kW* | = [2] / [4] | $945 | $887 | $925 | $949 |
| [7] | Levelized FOM | *$/kW-yr* | | $33 | $44 | $45 | $39 |
| [8] | **After-Tax WACC** | ***%*** | | **7.9%** | **8.0%** | **8.0%** | **8.0%** |
| [9] | Effective Charge Rate | *%* | | 11.7% | 11.6% | 11.6% | 11.6% |
| [10] | **Levelized CONE** | ***$/MW-yr*** | = [5] x [9] + [7] | **$138,000** | **$141,700** | **$147,100** | **$144,000** |
| [11] | **Levelized CONE** | ***$/MW-day*** | = [10] / 365 | **$378** | **$388** | **$403** | **$395** |

Similar to the CC, the CT CONE estimates vary by CONE Area primarily due to differences in labor rates (highest in EMAAC), firm gas contracts (highest in Rest of RTO), total income tax rates (highest in Rest of RTO and WMAAC), and property taxes (highest in SWMAAC).

The 2026/27 CT CONE estimates are considerably higher than in PJM's Base Residual Auction for the 2022/23 Delivery Year as shown in Figure 11. Similar to the presentation of CC CONE drivers, the attribution of changes to each element depends on the order in which the changes are implemented in our model. We estimated the impact of changes in bonus depreciation and ATWACC, then cost escalation, and finally, firm gas configuration.

**FIGURE 11: DRIVERS OF HIGHER CT 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)**




The drivers for higher CONE are explained below:

- Bonus Depreciation and ATWACC: The decline to 20% bonus depreciation by 2026 increases CONE by $21/MW-day (ICAP). The ATWACC decreased to 8.0%, decreasing CONE by $4/MW-day (ICAP), for a net effect of $17/MW-Day (ICAP).
- Cost Escalation: Cost escalation is lower relative to the CC due to a lower portion of materials and labor costs associated with the CT. As a result, the total cost escalation to 2026/27 adds $42/MW-Day (ICAP) to the 1x0 CT 2022/23 Dual Fuel CONE value.
- Firm Gas Configuration: The use of firm gas transportation contracts, adds $38/MW-Day (ICAP) to the 1x0 CT Updated Dual Fuel 2026/27 CONE.

# IV.E. Implications for Net CONE

## IV.E.1. Indicative E&AS Offsets

The E&AS offset methodology described for CCs would also apply to CTs, but recognizing two differences related to CTs' operation as peaking plants that are generally committed day-of. As peaking plants, their dispatch depends more on the hourly volatility of prices that cannot be observed directly in forward markets and are instead taken from historical hourly price shapes. Since historical prices do not fully reflect future conditions, the E&AS offset estimates for CTs may be subject to more uncertainty than for CCs (at least on a percentage basis). This observation does not lead to an obvious recommendation for improving the E&AS offset methodology for CTs but does contribute to our assessment of uncertainty in selecting a suitable reference resource, as discussed above.

The fact that CTs are generally committed day-of does require a slight adjustment to fuel cost inputs in the E&AS offset calculation. As we noted in our 2018 Study, "PJM commits and dispatches CTs during the operating day just a few hours before delivery, forcing them to arrange gas deliveries or to balance pre-arranged gas deliveries on the operating day. Generators may thus incur balancing penalties or have to buy or sell gas in illiquid intra-day markets. This may increase the average cost of procuring gas above the price implied by day-ahead hub prices. However, these costs are not transparent and may not follow regular patterns that are easily amenable to analysis. Our interviews with generation companies provided mixed reactions. Some with larger fleets claimed that they can manage their gas across their fleets without paying any more on average than the prices implied by the day-ahead hub prices. Others suggested that they might incur extra costs of up $0.30/MMBtu. We recommend that PJM investigate this further and consider applying the 10% cost offer adder allowed under PJM's Operating Agreement to the variable operating costs of the CTs in the simulations."[41] This time, we are not recommending a "10% adder" that FERC has recently rejected but, more precisely a 10% increase over (day-ahead) gas daily index prices (and no adder on CT VOM costs). This should provide reasonable and necessary adjustment to get more accurate fuel cost inputs.

The application of the CT E&AS offset methodology discussed above results in an updated E&AS due to a reduced ramp rate, the removal of transportation costs, then removal of regulation revenue. Table 27 shows the 2023/24 E&AS revenue offset by zone using the updated methodology.

41 2018 VRR Curve Study, pp. 23-24.

TABLE 27: UPDATED 2023/24 CT E&AS REVENUE OFFSET BY ZONE

| *All values in nominal $/MW-day ICAP* | CT | | | |
|---|---|---|---|---|
| | Current 2023/24 EAS | Updated Operating Costs | Removed Regulation | Updated 2023/24 EAS |
| **CONE Area 1** | | | | |
| AECO | $45 | -$4 | -$8 | $33 |
| DPL | $76 | -$2 | -$8 | $65 |
| JCPL | $43 | -$4 | -$8 | $32 |
| PECO | $48 | $4 | -$7 | $45 |
| PSEG | $41 | -$4 | -$8 | $30 |
| RECO | $48 | -$3 | -$8 | $36 |
| **CONE Area 2** | | | | |
| BGE | $93 | $6 | -$9 | $89 |
| PEPCO | $57 | -$1 | -$7 | $49 |
| **CONE Area 4** | | | | |
| METED | $65 | $8 | -$8 | $65 |
| PENELEC | $150 | $28 | -$12 | $166 |
| PPL | $52 | $5 | -$7 | $49 |
| **CONE Area 3** | | | | |
| AEP | $83 | $9 | -$12 | $79 |
| APS | $114 | $17 | -$13 | $118 |
| ATSI | $66 | $16 | -$8 | $75 |
| COMED | $47 | -$6 | -$7 | $34 |
| DAY | $70 | $21 | -$8 | $83 |
| DEOK | $74 | $17 | -$8 | $83 |
| DUQ | $81 | $15 | -$8 | $89 |
| DOM | $56 | -$1 | -$7 | $48 |
| EKPC | $80 | $11 | -$10 | $81 |
| **RTO** | **$48** | **-$1** | **-$8** | **$39** |

*Sources and notes:* The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020, including a 10% adder on all variable costs. The "Updated 2023/24 EAS" values do not reflect recommended changes to scaling historical hourly sync and non-sync reserve prices by forward energy prices, nor updating gas prices in EKPC's zone.

## IV.E.2. Indicative Net CONE

We apply the same methodology and assumptions to estimate the Net CONE shown for the reference CC. Table 28 shows the indicative CT Net CONE estimates for all LDAs relative to the parameters PJM used in the 2022/23 BRA.

### TABLE 28: INDICATIVE 2026/27 CT NET CONE

| *All values in nominal $/MW-day UCAP* | CT 2022/23 BRA | | | CT 2026/27 Brattle Estimate | | |
|---|---|---|---|---|---|---|
| | CONE | EAS | Net CONE | CONE | EAS | Net CONE |
| **CONE Area 1** | | | | | | |
| AECO | $312 | $47 | $265 | $397 | $48 | $349 |
| DPL | $312 | $76 | $236 | $397 | $85 | $312 |
| JCPL | $312 | $45 | $267 | $397 | $47 | $351 |
| PECO | $312 | $54 | $258 | $397 | $62 | $336 |
| PSEG | $312 | $43 | $268 | $397 | $44 | $353 |
| RECO | $312 | $50 | $262 | $397 | $52 | $346 |
| **EMAAC** | **$312** | **$52** | **$259** | **$397** | **$56** | **$341** |
| **CONE Area 2** | | | | | | |
| BGE | $317 | $90 | $226 | $408 | $113 | $315 |
| PEPCO | $317 | $57 | $260 | $408 | $67 | $315 |
| **SWMAAC** | **$317** | **$74** | **$243** | **$408** | **$93** | **$315** |
| **CONE Area 4** | | | | | | |
| METED | $305 | $67 | $238 | $415 | $85 | $315 |
| PENELEC | $305 | $139 | $166 | $415 | $200 | $210 |
| PPL | $305 | $54 | $250 | $415 | $67 | $315 |
| **MAAC** | **$311** | **$66** | **$245** | **$404** | **$79** | **$320** |
| **CONE Area 3** | | | | | | |
| AEP | $305 | $77 | $227 | $424 | $101 | $315 |
| APS | $305 | $102 | $203 | $424 | $146 | $315 |
| ATSI | $305 | $74 | $230 | $424 | $96 | $315 |
| COMED | $305 | $57 | $248 | $424 | $49 | $421 |
| DAY | $305 | $78 | $226 | $424 | $105 | $315 |
| DEOK | $305 | $81 | $224 | $424 | $106 | $315 |
| DUQ | $305 | $80 | $224 | $424 | $112 | $315 |
| DOM | $305 | $54 | $250 | $424 | $65 | $315 |
| EKPC | $305 | $76 | $229 | $424 | $103 | $315 |
| OVEC | $305 | $89 | $216 | $424 | $130 | $315 |
| **RTO** | **$309** | **$49** | **$260** | **$411** | **$55** | **$356** |

Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

# V. Battery Energy Storage Systems (BESS)

During the stakeholder process, several stakeholders raised concerns about whether natural-gas-fired resources (either CCs or CTs) will be feasible to build in certain zones due to state policies that require a decreasing portion of the generation mix to come from GHG-emitting resources. Based on this input, we reviewed several non-emitting resources to include as possible reference resources and determined that the 4-hour BESS best meets the reference resource screening criteria described in Section II above.

While 4-hour BESS is currently not recommended as the reference resource in any zone, its CONE value provides an initial estimate for PJM and its stakeholders a starting point for future reviews or before then if the recommended reference resource, the gas-fired CC, is determined to be infeasible to be built within the Quadrennial Review period.

## V.A. Technical Specifications

We developed the cost estimates for the 4-hour BESS based on the specifications listed in Table 29 below. We assumed the facility is sized for 200 MW at the point of interconnection, based on a review of the capacity of battery storage facilities currently in the PJM interconnection queue, utilizing lithium-ion battery chemistry and a containerized installation.

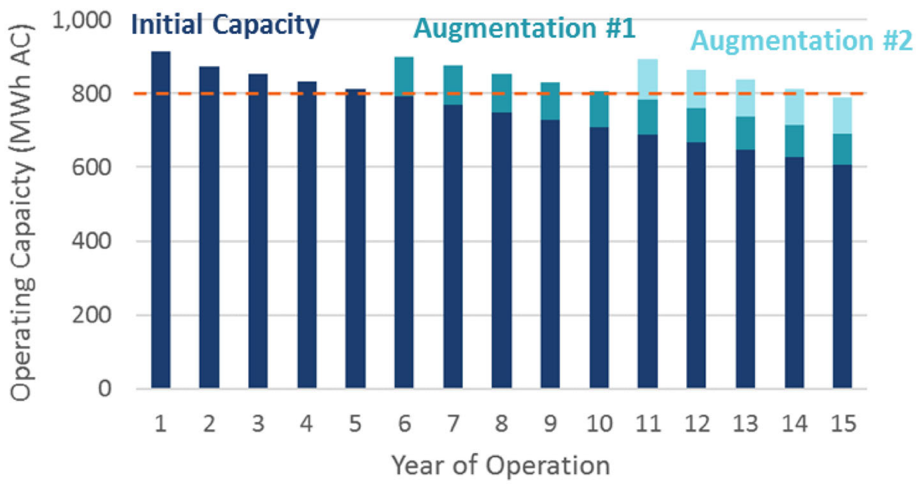
**TABLE 29: BESS TECHNICAL SPECIFICATIONS**

| Plant Characteristic | Specification |
|---|---|
| **Chemistry** | Lithium-ion |
| **Installation Configuration** | Containerized |
| **Rated Output Power (at POI)** | 200 MW-ac |
| **Duration** | 4 Hours |
| **Installed Energy Capacity** | 1,030 MWh-dc |
| **Annual Capacity Degradation** | 4% in Year 1, then 2% per year |
| **Augmentations** | Year 5 and Year 10 |
| **Use Case** | Daily Cycling |
| **Round Trip Efficiency** | 85% |
| **Economic Life** | 15 Years |
| **Salvage Value** | $0 |

S&L estimates that BESS energy capacity (in MWh or duration at full power) degrades by 4% in the first year and 2% in subsequent years, assuming daily cycling and a 5% minimum state of charge.[42] Developers are currently using a range of approaches to maintain sufficient capacity to provide the rated AC output at the POI over a four-hour period, including overbuilding the initial capacity and augmenting the capacity in future years. Overbuilding the initial capacity provides the developer greater cost certainty and reduces the frequency and costs of frequent augmentation events. On the other hand, a smaller overbuild defers capital expenditures to future augmentations that reduces the initial capital costs of the facility and may allow the owner to take advantage of declining module costs, depending on future cost trends. To account for degradation of the energy capacity, our cost estimate assumes that the facility will include an initial 13% overbuild, or 135 MWh-dc, with augmentations planned for Year 5 and Year 10. This is currently a common approach developers are taking, based on S&L's recent project experience, to reduce mobilization costs of frequent augmentation while still taking advantage of future costs declines.

[42] Degradation occurs due to many factors, including time, ambient conditions, state-of-charge, operational profiles, depth of discharge and manufacturing defects.

FIGURE 12: BESS EENRGY CAPCITY OVER 15 YEAR LIFE




Accounting for the assumed overbuild, minimum state of charge, and on-site losses, the total installed energy capacity is 1,030 MWh-dc, accounting for AC and inverter losses of 6.2%.[43]

TABLE 30: BESS SIZING ASSUMPTIONS

| Component | Value |
|---|---|
| **Rated AC Output Power (at POI)** | **200 MW-ac** |
| AC Losses | 4.6% |
| Inverter Losses | 1.6% |
| **Gross DC Power Output** | **212 MW-dc** |
| Minimum State of Charge | 5.0% |
| Duration | 4 hours |
| **Gross Energy Capacity** | **895 MWh-dc** |
| Overbuild due to Degradation | 13%, or 135 MWh-dc |
| **Installed Energy Capacity** | **1,030 MWh-dc** |

Note: Gross Energy Capacity represents the required capacity to achieve nameplate rated output power on the first day of operation

43 AC losses include power control system and generator step-up transformer losses, line losses, and auxiliary load.

## V.B. Capital Costs

As explained in more detail below, we estimated the 4-hour BESS CONE value using a top-down cost estimating approach that involves less detailed specification of the resource and its location for developing cost estimates. S&L estimated the EPC costs based on recent project data, establishing unitized costs for project components and scaling to the selected reference technology specifications with adjustments to account for labor rates in each CONE Area. S&L then verified the total installed costs against publicly available cost estimates for similar BESS resources.

We estimated the non-EPC costs using similar assumptions as the CC and CT for the per-kW costs of electrical interconnection and per-acre land costs. The remaining non-EPC costs components are estimated based on a percentage of total EPC with the same assumption as the CC and CT for project development, mobilization and start-up, and financing fees. We assumed a lower Owner's Contingency of 5% of BESS equipment costs instead of 8% for the CC and CT based on the larger share of costs covered by the EPC contract.

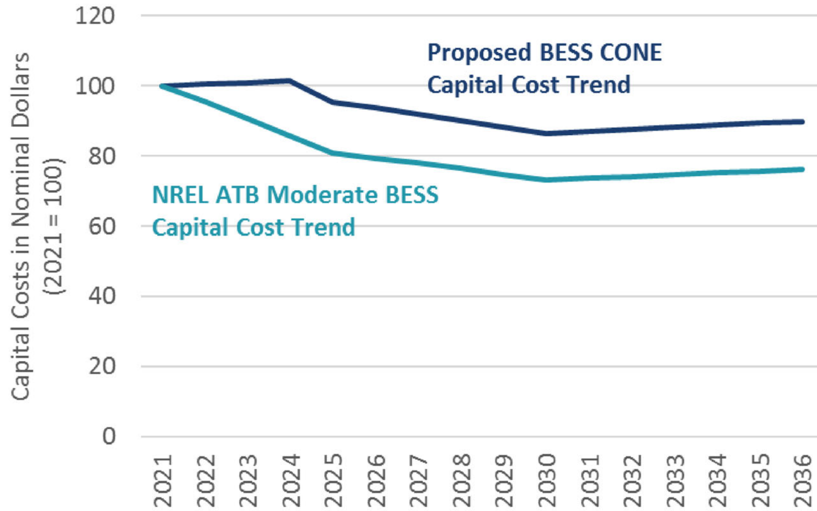
Based on the technical specifications for the reference BESS described above, the total capital costs for plants with an online date of June 1, 2026 are shown in Table 31 below. EPC costs are primarily driven by the costs of the batteries and enclosures, which is currently estimated to be about $190/kWh-dc (in 2021 dollars). The EPC Contractor Fee and Contingency costs are assumed to be incorporated into the other BESS EPC costs.

**TABLE 31: PLANT CAPITAL COSTS FOR BESS REFERENCE RESOURCE IN NOMINAL $ FOR 2026 ONLINE DATE**

| | CONE Area | | | |
|---|---|---|---|---|
| | 1 | 2 | 3 | 4 |
| | EMAAC | SWMAAC | Rest of RTO | WMAAC |
| **Capital Costs (in $millions)** | *200 MW* | *200 MW* | *200 MW* | *200 MW* |
| **EPC Costs** | | | | |
| BESS Equipment | | | | |
| Batteries and Enclosures | $193.5 | $193.5 | $193.5 | $193.5 |
| PCS and BOP Equipment | $29.0 | $29.0 | $29.0 | $29.0 |
| Project Management | $11.8 | $9.4 | $10.0 | $10.8 |
| Construction & Materials | $58.7 | $46.9 | $49.6 | $53.6 |
| Sales Tax | $0.0 | $0.0 | $0.0 | $0.0 |
| EPC Contractor Fee | Included | Included | Included | Included |
| EPC Contingency | Included | Included | Included | Included |
| **Total EPC Costs** | **$293.0** | **$278.8** | **$282.0** | **$286.9** |
| **Non-EPC Costs** | | | | |
| Project Development | $14.7 | $13.9 | $14.1 | $14.3 |
| Mobilization and Start-Up | $2.9 | $2.8 | $2.8 | $2.9 |
| Owner's Contingency | $11.1 | $11.1 | $11.1 | $11.1 |
| Electrical Interconnection | $4.1 | $4.1 | $4.1 | $4.1 |
| Land | $0.4 | $0.3 | $0.2 | $0.4 |
| Working Capital | $0.0 | $0.0 | $0.0 | $0.0 |
| Financing Fees | $1.3 | $1.3 | $1.3 | $1.3 |
| **Total Non-EPC Costs** | **$34.6** | **$33.6** | **$33.6** | **$34.1** |
| **Total Capital Costs** | **$327.6** | **$312.4** | **$315.7** | **$321.0** |
| **Overnight Capital Costs ($million)** | **$328** | **$312** | **$316** | **$321** |
| **Overnight Capital Costs ($/kW)** | **$1,638** | **$1,562** | **$1,578** | **$1,605** |
| **Installed Capital Costs ($/kW)** | **$1,725** | **$1,646** | **$1,663** | **$1,691** |
| **Installed Capital Costs ($/kWh)** | **$409** | **$390** | **$395** | **$401** |

Similar to the CC and CT, all equipment and material costs are initially estimated by S&L in 2021 dollars and escalated to the construction period for an online date of June 1, 2026 based on a 16-month construction drawdown schedule for BESS resources. We estimate the overnight capital cost for the BESS incurred during the construction period, as shown in Figure 13 below. S&L estimates that costs will decline in real terms by -1.5% per year from 2021 to 2024 (or +1.4% per year in nominal terms, given assumed inflation of 2.9% per year), based on contract data, trends, and expectations expressed by suppliers for projects currently in development. From 2024 to 2026, we then assume costs will decline in nominal terms based on the 2021 NREL Annual Technology Baseline Moderate cost projections. We use this approach as well for estimating augmentation costs in 2031 (Year 5) and 2036 (Year 10).

FIGURE 13: PROJECTED BESS CAPITAL COST TRENDS




## V.C. Operation and Maintenance Costs

Once the BESS plant enters commercial operation, the plant owners incur fixed O&M costs each year. Table 9 summarizes the annual fixed O&M costs, variable O&M costs, and augmentation costs in Year 5 and Year 10 for BESS with an online date of June 1, 2026. The annual O&M costs primarily include the fixed costs of the O&M contract for the facility and the costs of operating insurance.

As shown in Figure 12 above, the BESS storage capacity will fall below 800 MWh-ac in Year 6 based on the assumed initial overbuild and degradation rates. To maintain its 4-hour duration at 200 MW of output power through the economic life of the asset, we assume the developer will add 124 MWh-dc of additional battery modules in Year 5 at a cost of $30.5 million (in 2031 dollars) and another 124 MWh-dc of capacity in Year 10 at $33.1 million (in 2036 dollars).[44]

[44] Augmentation costs reflect the current estimate of module of $190/kWh plus a 20% markup for mobilization and installation costs and the projected trend in module costs shown in Figure 13.

TABLE 32: O&M COSTS FOR BESS REFERENCE RESOURCE

| O&M Costs | CONE Area<br>1<br>EMAAC<br>*200 MW* | <br>2<br>SWMAAC<br>*200 MW* | <br>3<br>Rest of RTO<br>*200 MW* | <br>4<br>WMAAC<br>*200 MW* |
|---|---|---|---|---|
| **Fixed O&M Components** | | | | |
| O&M Contract Fixed Payments | $2.7 | $2.7 | $2.7 | $2.7 |
| BOP and Substation O&M | $0.1 | $0.1 | $0.1 | $0.1 |
| Station Load / Aux Load | $0.4 | $0.3 | $0.3 | $0.4 |
| Miscellaneous Owner Costs | $0.3 | $0.2 | $0.3 | $0.3 |
| Operating Insurance | $1.3 | $1.2 | $1.3 | $1.3 |
| Land Lease or Property Taxes | $2.3 | $4.4 | $2.1 | $2.0 |
| **Fixed O&M (2026$ million)** | **$7.1** | **$9.0** | **$6.7** | **$6.7** |
| **Fixed O&M ($/kW-yr)** | **$35.3** | **$44.8** | **$33.6** | **$33.7** |
| **Augmentation** | | | | |
| Year 5 Costs (2031$ million) | **$30.5** | **$30.5** | **$30.5** | **$30.5** |
| Year 10 Costs (2036$ million) | **$33.1** | **$33.1** | **$33.1** | **$33.1** |
| **Levelized Augmentation Costs ($/kW-yr)** | **$22.3** | **$22.3** | **$22.3** | **$22.3** |
| **Total Levelized Fixed Costs ($/kW-yr)** | **$57.7** | **$67.1** | **$55.9** | **$56.1** |

The total levelized fixed O&M costs represent the total contribution of these costs to the CONE value, including both the annual fixed costs ($23/kW-year to $42/kW-year) and the levelized costs of the two capacity augmentations (about $28/kW-year). While some O&M costs may vary with operation, these estimates were prepared with static operational assumptions and commensurate auxiliary loads, degradation, and augmentation profiles. All O&M and augmentation costs for the BESS are accounted for in Table 32 and the variable O&M costs are assumed to be $0.

## V.D. CONE Estimates

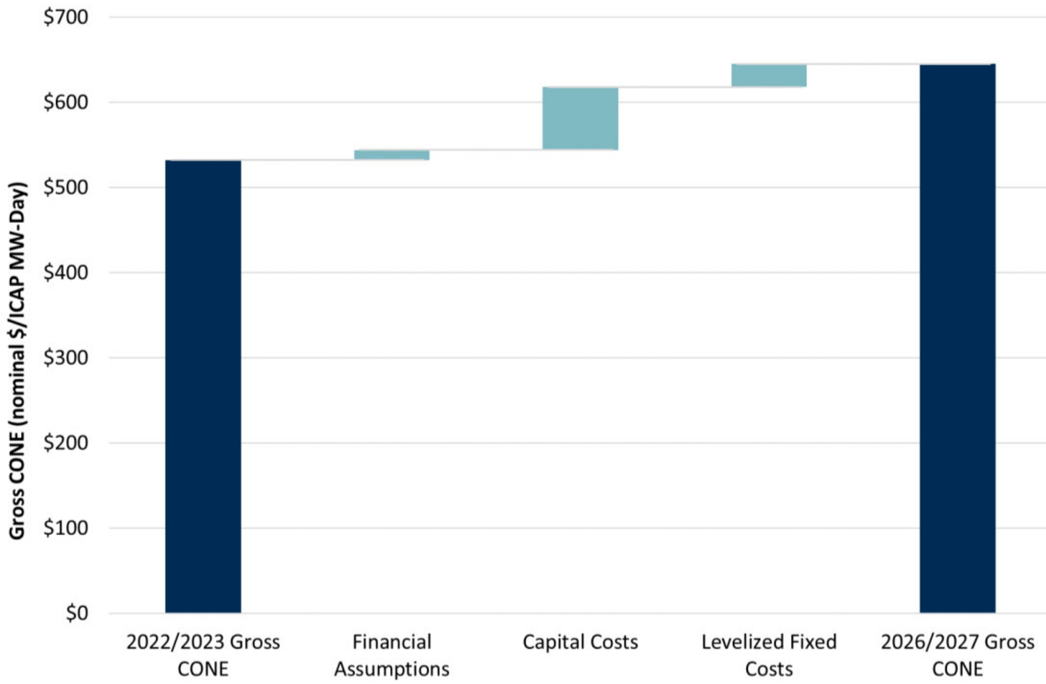
The administrative Gross CONE value reflects the total annual net revenues a new generation resource needs to earn on average to recover its capital investment and annual fixed costs, given reasonable expectations about future cost recovery over its economic life. Table 33 summarizes plant capital costs, annual fixed costs, and levelized CONE estimates for the BESS reference resource for the 2026/27 delivery year. The CONE estimates range from $653/MW-day in Rest of RTO to $678/MW-day in EMAAC.

TABLE 33: ESTIMATED CONE FOR BESS FOR 2026/27 IN 2026$ AND ICAP MW

| | | | 4-Hour Battery Storage | | | |
|---|---|---|---|---|---|---|
| | | | EMAAC | SWMAAC | Rest of RTO | WMAAC |
| | **Net Summer ICAP** | ***MW*** | **200** | **200** | **200** | **200** |
| | **Gross Costs** | | | | | |
| [1] | Overnight | *$m* | $328 | $312 | $316 | $321 |
| [2] | Installed (inc. IDC) | *$m* | $345 | $329 | $333 | $338 |
| [3] | First Year FOM | *$m/yr* | $7 | $9 | $7 | $7 |
| [4] | Year 5 Augmentation | *$m* | $31 | $31 | $31 | $31 |
| [5] | Year 10 Augmentation | *$m* | $33 | $33 | $33 | $33 |
| | **Unitized Costs** | | | | | |
| [7] | Overnight | *$/kW* | $1,638 | $1,562 | $1,578 | $1,605 |
| [8] | Installed (inc. IDC) | *$/kW* | $1,725 | $1,646 | $1,663 | $1,691 |
| [9] | Levelized Fixed Costs | *$/kW-yr* | $66 | $69 | $64 | $64 |
| [10] | **After-Tax WACC** | ***%*** | **7.9%** | **8.0%** | **8.0%** | **8.0%** |
| [11] | Effective Charge Rate | *%* | 11.1% | 11.0% | 11.1% | 11.1% |
| [12] | **Updated CONE** | ***$/MW-yr*** | **$247,400** | **$240,900** | **$238,400** | **$241,500** |
| [13] | **Updated CONE** | ***$/MW-day*** | **$678** | **$660** | **$653** | **$662** |

Similar to the CC and CT, the 2026/27 BESS CONE estimates are considerably higher than PJM's estimated CONE for the 2022/23 Delivery Year Base Residual Auction, as shown in Figure 14. PJM estimated the 2022/23 CONE based on cost estimates from the NREL Annual Technology Baseline. As described above, the updated estimates for the 2026/27 auction reflect more detailed specifications for a 200 MW facility in the PJM market and recent cost estimates based on actual projects currently under development, including recent cost escalation. As shown in Figure 13 above, the current outlook for BESS capital costs are about 15% higher than those projected by NREL in its latest ATB. The higher capital costs also reflect the assumed overbuild of capacity to account for degradation, whereas NREL assumed no overbuild and annual augmentation. The higher O&M costs reflect the recent costs of maintenance contracts as well as a more up-to-date outlook for future augmentation costs.

FIGURE 14: DRIVERS OF HIGHER BESS 2026/27 CONE ESTIMATES (AVERAGE ACROSS ALL CONE AREAS)




# V.E. Implications for Net CONE

## V.E.1. Indicative E&AS Offsets

Similar to the CC and CT, we recommend removing regulation revenues from the calculation of the E&AS offset for BESS. The regulation market is unlikely to continue to support similar prices in the future with the addition of significant BESS resources, especially in the case in which BESS resource are one of the primary resources that enter the market to meet future reserve requirements.

Removing regulation revenues has a greater impact on BESS E&AS offset than the CC and CT though because it currently makes up the majority of its revenues. Table 34 shows the current and updated 2023/24 E&AS revenue offset by zone with the steep decrease caused by the removal of regulation revenues.

TABLE 34: UPDATED 2023/24 BESS E&AS REVENUE OFFSET BY ZONE ($/MW-DAY ICAP)

| *All values in nominal $/MW-day ICAP* | 4-Hour BESS | | |
|---|---|---|---|
| | Current 2023/24 EAS | Removed Regulation | Updated 2023/24 EAS |
| **CONE Area 1** | | | |
| AECO | $414 | -$294 | $120 |
| DPL | $427 | -$285 | $142 |
| JCPL | $413 | -$295 | $118 |
| PECO | $413 | -$295 | $118 |
| PSEG | $414 | -$294 | $120 |
| RECO | $419 | -$291 | $128 |
| **CONE Area 2** | | | |
| BGE | $428 | -$267 | $161 |
| PEPCO | $423 | -$274 | $149 |
| **CONE Area 4** | | | |
| METED | $417 | -$286 | $132 |
| PENELEC | $419 | -$290 | $128 |
| PPL | $416 | -$292 | $124 |
| **CONE Area 3** | | | |
| AEP | $418 | -$286 | $132 |
| APS | $418 | -$284 | $134 |
| ATSI | $419 | -$284 | $135 |
| COMED | $425 | -$281 | $144 |
| DAY | $420 | -$281 | $139 |
| DEOK | $421 | -$280 | $141 |
| DUQ | $421 | -$283 | $139 |
| DOM | $424 | -$276 | $149 |
| EKPC | $418 | -$285 | $134 |
| OVEC | $407 | -$295 | $113 |
| **RTO** | **$343** | **-$215** | **$128** |

*Sources and notes:* The "Current 2023/24 E&AS" reflects the forward-looking E&AS values provided by PJM under the approach implemented in 2020.

## V.E.2. Indicative Net CONE

We apply the same methodology and assumptions to estimate the BESS Net CONE shown for the reference CC. Table 28 Table 35 shows the indicative BESS Net CONE estimates for all LDAs relative to the parameters PJM used in the 2022/23 BRA.

TABLE 35: INDICATIVE BESS 2026/2027 NET CONE ($/MW-DAY UCAP)

| *All values in nominal $/MW-day UCAP* | BESS 2026/27 Brattle Estimate | | |
|---|---|---|---|
| | CONE | EAS | Net CONE |
| **CONE Area 1** | | | |
| AECO | $858 | $178 | $679 |
| DPL | $858 | $208 | $649 |
| JCPL | $858 | $175 | $682 |
| PECO | $858 | $175 | $683 |
| PSEG | $858 | $179 | $679 |
| RECO | $858 | $189 | $668 |
| **EMAAC** | **$858** | **$184** | **$674** |
| **CONE Area 2** | | | |
| BGE | $875 | $234 | $641 |
| PEPCO | $875 | $219 | $656 |
| **SWMAAC** | **$875** | **$227** | **$648** |
| **CONE Area 4** | | | |
| METED | $843 | $194 | $648 |
| PENELEC | $843 | $190 | $653 |
| PPL | $843 | $184 | $659 |
| **MAAC** | **$857** | **$193** | **$663** |
| **CONE Area 3** | | | |
| AEP | $830 | $195 | $635 |
| APS | $830 | $198 | $632 |
| ATSI | $830 | $199 | $631 |
| COMED | $830 | $211 | $619 |
| DAY | $830 | $204 | $625 |
| DEOK | $830 | $208 | $622 |
| DUQ | $830 | $204 | $626 |
| DOM | $830 | $218 | $612 |
| EKPC | $830 | $197 | $633 |
| OVEC | $830 | $168 | $662 |
| **RTO** | **$851** | **$189** | **$662** |

Sources *and notes:* RTO Gross CONE is an average of the Gross CONE across all CONE Areas, but the E&AS offset is based on a single virtual dispatch using averaged electricity and gas price inputs, consistent with the Net CONE calculation used to set the parameters of the RTO VRR curve.

# VI. List of Acronyms

| | |
|---|---|
| ATWACC | After-Tax Weighted-Average Cost of Capital |
| BACT | Best Available Control Technology |
| BLS | Bureau of Labor Statistics |
| BRA | Base Residual Auction |
| Btu | British Thermal Units |
| CAISO | California Independent System Operator |
| CC | Combined Cycle |
| CO | Carbon Monoxide |
| COD | Cost of Debt |
| CONE | Cost of New Entry |
| CPI | Consumer Price Index |
| CT | Combustion Turbine |
| DCP | Dominion Cove Point |
| DJIA | Dow Jones Industrial Average |
| E&AS | Energy and Ancillary Services |
| EIA | Energy Information Administration |
| EMAAC | Eastern Mid-Atlantic Area Council |
| EPC | Engineering, Procurement, and Construction |
| FERC | Federal Energy Regulatory Commission |
| HRSG | Heat Recovery Steam Generator |
| ICAP | Installed Capacity |
| IDC | Interest During Construction |
| ISO | Independent System Operator |
| ISO-NE | ISO New England |
| kW | Kilowatt |
| kWh | Kilowatt-Hours |
| LDA | Locational Deliverability Area |
| LAER | Lowest Achievable Emissions Rate |
| LTSA | Long-Term Service Agreement |
| m | Million |

| | |
|---|---|
| MAAC | Mid-Atlantic Area Council |
| MACRS | Modified Accelerated Cost Recovery System |
| MMBtu | One Million British Thermal Units |
| MOPR | Minimum Offer Price Rule |
| MW | Megawatt(s) |
| MWh | Megawatt-Hours |
| NNSR | Non-Attainment New Source Review |
| $NO_x$ | Nitrogen Oxides |
| NPV | Net Present Value |
| NSR | New Source Review |
| NYISO | New York Independent System Operator |
| O&M | Operation and Maintenance |
| OATT | Open Access Transmission Tariff |
| OFE | Owner-Furnished Equipment |
| OTR | Ozone Transport Region |
| PILOT | Payment in Lieu of Taxes |
| PJM | PJM Interconnection, LLC |
| PPI | Producer Price Index |
| PSD | Prevention of Significant Deterioration |
| ROE | Return on Equity |
| RPM | Reliability Pricing Model |
| RTO | Regional Transmission Organization |
| S&L | Sargent & Lundy |
| SCR | Selective Catalytic Reduction |
| SWMAAC | Southwestern Mid-Atlantic Area Council |
| ULSD | Ultra-Lower Sulfur Diesel |
| VOC | Volatile Organic Compounds |
| VRR | Variable Resource Requirement |
| WMAAC | Western Mid-Atlantic Area Council |

# Appendix A: Combined-Cycle and Combustion Turbine Cost Details

## A.1 Technical Specifications

The 2018 PJM CONE study demonstrated that the market was shifting away from the F-class and G-class frame type turbines that had been the dominant turbines over the prior several decades and with over half of the CC plants installed or under construction in PJM. Today, developers even more definitively exhibit preference for H/J-class turbines. Table 36 shows 72% and 58% of CC capacity under construction (since 2018) is from H/J-class turbines in PJM and the U.S., respectively. Among all such turbines, developers continue to select GE 7HA turbine, building on the industry's many turbine-years of operating experience with that make and model. Other equivalent machines to the GE H-class machine such as the Siemens SGT6-8000H or the Mitsubishi M501J currently have lower market penetration.

**TABLE 36: TURBINE MODEL OF COMBINED-CYCLE PLANTS BUILT OR UNDER CONSTRUCTION IN PJM SINCE 2018**

| Turbine Model | PJM Installed Capacity *(MW)* | US Installed Capacity *(MW)* |
|---|---|---|
| General Electric 7HA | 7,211 | 12,203 |
| Mitsubishi M501J | 3,645 | 3,645 |
| Siemens SGT6-8000H | 1,856 | 1,856 |
| Mitsubishi M501G | 1,444 | 4,015 |
| General Electric 7F | 828 | 4,130 |
| Siemens SGT6-5000F | 755 | 1,426 |
| General Electric A650 | 717 | 717 |
| Siemens SGT6-500 | 703 | 703 |
| General Electric 6B.03 | 276 | 276 |
| General Electric GRT | 210 | 210 |
| General Electric MS7001 | 0 | 1,000 |
| Siemens SGT6-2000 | 0 | 232 |
| Siemens SGT6-800 | 0 | 224 |
| Solar Turbines Titan 130 | 0 | 29 |
| **Total** | **17,645** | **30,666** |
| F/G Class Total | 3,940 | 10,485 |
| H/J Class Total | 12,712 | 17,704 |

Sources and notes: Data is from Ventyx Energy Velocity Suite and S&P Global Market Intelligence, Accessed August 2021.

Sargent & Lundy reviewed the operational characteristics of starting up each reference resource and updated the parameters PJM includes in its historical simulations for setting the Net E&AS revenue offset in Table 37.

**TABLE 37: RECOMMENDED OPERATING PARAMETERS FOR REFERENCE RESOURCES**

| Parameter | Unit | CT | CC |
|---|---|---|---|
| Installed Capacity | *MW* | 367 | 1,182 |
| Minimum Stable Level | *MW* | 140 | 176 |
| Ramp Rate | *MW/min* | 15 | 30 |
| Time to Start | *mins* | 21 | 120 |
| Minimum Runtime | *hours* | 2 | 4 |
| NOx Rate | *lb/MMBtu* | 0.0093 | 0.0074 |
| SO2 Rate | *lb/MMBtu* | 0.0006 | 0.0006 |
| Startup Gas Usage | *MMBtu/start* | 456 | 7,988 |
| Startup NOx Emissions | *lb/start* | 55 | 160 |

## A.2 Construction Labor Costs

Labor costs are comprised of “construction labor” associated with the EPC scope of work and “other labor” that includes engineering, procurement, project services, construction management, field engineering, start-up, and commissioning services. The labor rates in this analysis do not reflect a specific assumption of whether union or non-union labor is utilized. Labor rates have been developed by S&L through a survey of prevalent wages in each region in 2021. The labor costs for a given task are based on trade rates weighted by the combination of trades required. In areas where multiple labor pools can be drawn upon the trade rates used are the average of the possible labor rates. The labor costs are based on a 5-day 10-hour workweek with per-diem included to attract skilled labor. Site overheads are carried as indirect costs, which is consistent with current industry practice whereas in 2014 site overheads were carried in the labor rates.

A summary of construction labor cost assumptions is shown below in Table 38.

TABLE 38: CONSTRUCTION LABOR COST ASSUMPTIONS

| | | EMAAC | SWMAAC | Rest of RTO | WMAAC |
|---|---|---|---|---|---|
| **1x0 CT Plant** | | | | | |
| 2021 Construction Labor Hours | *hours* | 256,453 | 239,508 | 243,744 | 256,453 |
| 2021 Weighted Average Crew Rates | *$* | 137.66 | 118.34 | 122.59 | 122.44 |
| 2021 Productivity Factor | -- | 1.18 | 1.10 | 1.12 | 1.18 |
| 2021 Construction Labor Costs | *$* | $41,657,600 | $31,178,500 | $33,466,500 | $37,051,400 |
| 2021 Construction Labor Costs | *$/kW* | 115 | 86 | 95 | 106 |
| **Double Train 1x1 CC Plant** | | | | | |
| 2021 Construction Labor Hours | *hours* | 1,809,038 | 1,687,939 | 1,718,213 | 1,809,038 |
| 2021 Weighted Average Crew Rates | *$* | 143.62 | 127.97 | 129.48 | 129.85 |
| 2021 Productivity Factor | -- | 1.18 | 1.10 | 1.12 | 1.18 |
| 2021 Construction Labor Costs | *$* | $306,589,500 | $237,598,100 | $249,164,300 | $277,181,900 |
| 2021 Construction Labor Costs | *$/kW* | 294 | 227 | 244 | 274 |

Engineering, procurement, and project services are taken as 5% of project direct costs. Construction management and field engineering is taken as 2% of project direct costs. Start-up and commissioning is taken as 1% of project direct costs. These values are consistent with the 2018 CONE Study and are in-line with recent projects in which S&L has been involved.

## A.3 Net Startup Fuel Costs

We made the following assumptions to calculate net start-up fuel costs:

- **Natural Gas**: assume zone-specific gas prices, including Transco Zone 6 Non-New York prices for EMAAC, Transco Zone 5 prices for SWMAAC, Columbia Appalachia prices for Rest of RTO, and Transco Leidy Receipts for WMAAC. All gas prices were calculated by using future/forward natural gas prices from OTC Global Holdings as of 10/10/2021 to estimate 2022 gas prices.
- **Electric Energy:** estimate prices based on zone-specific energy prices for the location of the reference resources in each CONE Area: AECO for EMAAC, PEPCO for SWMAAC, AEP for Rest of RTO, and PPL for WMAAC;[45] average the resulting estimates for locational day-ahead on-peak and off-peak energy prices to estimate the average revenues that would be received during testing.

45 Electricity prices were estimated following the approach discussed in Section II.B of the concurrently released VRR Curve report.

**TABLE 39: STARTUP PRODUCTION AND FUEL CONSUMPTION DURING TESTING**

| | Energy Production | | | Fuel Consumption | | | |
|---|---|---|---|---|---|---|---|
| | Energy Produced | Energy Price | Energy Sales Credit | Natural Gas | Natural Gas Price | Natural Gas Cost | Total Cost |
| | *(MWh)* | *($/MWh)* | *($m)* | *(MMBtu)* | *($/MMBtu)* | *($m)* | *($m)* |
| **Gas CT** | | | | | | | |
| 1 Eastern MAAC | 178,130 | $36.24 | $6.46 | 1,636,480 | $3.61 | $5.9 | -$0.6 |
| 2 Southwest MAAC | 179,290 | $36.24 | $6.50 | 1,647,134 | $3.61 | $5.9 | -$0.6 |
| 3 Rest of RTO | 173,913 | $32.45 | $5.64 | 1,598,262 | $3.61 | $5.8 | $0.1 |
| 4 Western MAAC | 172,584 | $36.24 | $6.25 | 1,586,224 | $3.61 | $5.7 | -$0.5 |
| **Gas CC** | | | | | | | |
| 1 Eastern MAAC | 1,027,945 | $36.24 | $37.26 | 6,468,335 | $3.61 | $23.3 | -$13.9 |
| 2 Southwest MAAC | 1,034,170 | $36.24 | $37.48 | 6,509,687 | $3.61 | $23.5 | -$14.0 |
| 3 Rest of RTO | 1,003,905 | $32.45 | $32.57 | 6,316,673 | $3.61 | $22.8 | -$9.8 |
| 4 Western MAAC | 996,320 | $36.24 | $36.11 | 6,269,141 | $3.61 | $22.6 | -$13.5 |

Sources and notes: Energy production and fuel consumption estimated by S&L. Energy prices estimated by Brattle based on approach discussed in Section II.B of VRR curve report. Gas prices from OTC Global Holdings as of 10/10/2021.

## A.4 Gas and Electric Interconnection Costs

Similar to the 2018 PJM CONE Study, we identified representative gas pipeline lateral projects from the EIA U.S. Natural Gas Pipeline Projects database and obtained project-specific costs from each project's FERC docket for calculating the average per-mile lateral cost and metering station costs. We escalated the project-specific costs to 2021 dollars based on the assumed long-term inflation rate of 2.4% (see Table 8 above). We then calculated the average per-mile costs of the laterals ($5.1 million/mile) and the station costs ($4.1 million). The summary of project costs and the average per-mile pipeline cost and metering station cost are shown in Table 40.[46]

[46] The gas lateral projects were identified from the EIA's "U.S. natural gas pipeline projects" database available at http://www.eia.gov/naturalgas/data.cfm. The detailed costs are from each project's FERC application, which can be found by searching for the project's docket at http://elibrary.ferc.gov/idmws/docket_search.asp.

## TABLE 40: GAS INTERCONNECTION COSTS

| Gas Lateral Project | State | In-Service Year | Pipeline Width *(inches)* | Pipeline Length *(miles)* | Pipeline Cost *(service year $m)* | Pipeline Cost *(2021$m)* | Pipeline Cost *(2021$m/mile)* | Meter Station *(Y/N)* | Station Cost *(service year $m)* | Station Cost *(2021$m)* |
|---|---|---|---|---|---|---|---|---|---|---|
| Panda Power Lateral Project | TX | 2014 | 16 | 16.5 | $26 | $31 | $2 | Y | $2.2 | $2.6 |
| Woodbridge lateral | NJ | 2015 | 20 | 2.4 | $32 | $37 | $15 | Y | $3.5 | $4.0 |
| Rock Springs Expansion | PA,MD | 2016 | 20 | 11.0 | $80 | $90 | $8 | Y | $3.3 | $3.7 |
| Western Kentucky Lateral Project | KY | 2016 | 24 | 22.5 | $81 | $91 | $4 | Y | $4.8 | $5.4 |
| UGI Sunbury Pipeline | PA | 2017 | 20 | 35.0 | $178 | $196 | $6 | Y | n.a. | n.a. |
| Willis Lateral Project | TX | 2020 | 24 | 19.0 | $96 | $98 | $5 | Y | $4.3 | $4.4 |
| **Average** | | | | | | | **$5.1** | | | **$4.0** |

Sources and notes: A list of recent gas lateral projects were identified based on an EIA dataset (http://www.eia.gov/naturalgas/data.cfm) and detailed cost information was obtained from the project's application with FERC, which can be retrieved from the project's FERC docket (available at http://elibrary.ferc.gov/idmws/docket_search.asp).

Table 41 below summarizes the average electrical interconnection costs of recently installed gas-fired resources that we identified as representative of the CC reference resources. The costs are based on confidential, project-specific cost data provided by PJM for both the direct connection facilities and all necessary network upgrades. In the case where plants chose to build their own direct connection facilities and did not report their costs to PJM, we calculated the capacity-weighted average of the units with direct connection costs and applied them to the units without direct connection costs. We escalated the direct connection and network upgrade costs from the online service dates to 2021 dollars based on the assumed long-term inflation rate of 2.9%. We then calculated the capacity-weighted average costs. We used the capacity-weighted average across all representative plants of $18.9/kW for setting the electrical interconnection of the CC reference resource.

## TABLE 41: ELECTRIC INTERCONNECTION COSTS IN PJM

| Plant Size | Observations *(count)* | Electrical Interconnection Cost Capacity Weighted Average *(2021$m)* | *(2021$/kW)* |
|---|---|---|---|
| < 500 MW | 5 | $7.2 | $18.3 |
| 500-750 MW | 5 | $12.2 | $20.7 |
| > 750 MW | 7 | $23.9 | $18.3 |
| **Capacity Weighted Average** | **17** | **$18.8** | **$18.9** |

*Source and notes:* Confidential project-specific cost data provided by PJM.

## A.5 Land Costs

We estimated the cost of land by reviewing current asking prices for vacant industrial land greater than 10 acres for sale in each selected county. We collected all publicly-available land listings for counties within each CONE area. We then calculated the acre-weighted average land price for each CONE area and escalated 1 year using the long-term inflation rate of 2.2%. There is a wide range of prices within the same CONE Area as shown in Table 42.

**TABLE 42: CURRENT LAND ASKING PRICES**

| **CONE Area** | **Current Asking Prices** | | |
|---|---|---|---|
| | Observations *(count)* | Range *(2022$/acre)* | Land Price *(2022$/acre)* |
| 1 EMAAC | 7 | $14,430 - $206,620 | $96,361 |
| 2 SWMAAC | 2 | $13,148 - $42,785 | $29,504 |
| 3 RTO | 6 | $9,867 - $37,429 | $16,376 |
| 4 WMAAC | 6 | $22,49 - $68,14 | $30,628 |

Sources and notes: We researched land listing prices on LoopNet's Commercial Real Estate Listings (www.loopnet.com) and on LandAndFarm (www.landandfarm.com).

## A.6 Property Taxes

Table 43 summarizes the calculations for the effective tax rates of each CONE area. We collected nominal tax rates, assessment ratios, and depreciation rates for counties of each CONE area. Using the nominal tax rates and assessment ratios, the effective tax rate for each CONE area was calculated by multiplying the average nominal tax rate and assessment ratio for counties within each CONE area state.

## TABLE 43: PROPERTY TAX RATE ESTIMATES FOR EACH CONE AREA

| | | Real Property Tax | | | Personal Property Tax | | | |
|---|---|---|---|---|---|---|---|---|
| | | Nominal Tax Rate | Assessment Ratio | Effective Tax Rate | Nominal Tax Rate | Assessment Ratio | Effective Tax Rate | Depreciation |
| | | [a] | [b] | [a] X [b] | [c] | [d] | [c] X [d] | [e] |
| | | *(%)* | *(%)* | *(%)* | *(%)* | *(%)* | *(%)* | *(%/yr)* |
| **1 EMAAC** | | | | | | | | |
| New Jersey | [1] | 4.0% | 96.2% | 3.8% | n/a | n/a | n/a | n/a |
| **2 SWMAAC** | | | | | | | | |
| Maryland | [2] | 1.1% | 100.0% | 1.1% | 2.7% | 50.0% | 1.3% | 3.3% |
| **3 RTO** | | | | | | | | |
| Ohio | [3] | 5.5% | 35.0% | 1.9% | 5.5% | 24.0% | 1.3% | See "SchC-NewProd (NG)" Annual Report |
| Pennsylvania | [4] | 2.7% | 100.0% | 2.7% | n/a | n/a | n/a | n/a |
| **4 WMAAC** | | | | | | | | |
| Pennsylvania | [5] | 3.8% | 99.0% | 3.8% | n/a | n/a | n/a | n/a |

*Sources and Notes:*

[1a],[1b] New Jersey rates estimated based on the average effective tax rates from Gloucester and Camden counties. For Gloucester County see:
https://tax1.co.monmouth.nj.us/cgi-bin/prc6.cgi?&ms_user=monm&passwd=data&srch_type=0&adv=0&out_type=0&district=0801
For Camden county see:
https://www.camdencounty.com/wp-content/uploads/2020/11/04CAMDEN.2021-Ratios.pdf
https://www.camdencounty.com/wp-content/uploads/2020/11/2021-County-Tax-Rates.pdf

[1c],[1d] No personal property tax assessed on power plants in New Jersey; NJ Rev Stat § 54:4-1 (2016).

[2a],[2c] Maryland tax rates estimated based on average county tax rates in Charles county and Prince George's county in 2017-2018. Data obtained from Maryland Department of Assessments & Taxation website:
https://dat.maryland.gov/Documents/statistics/Taxrates_2021.pdf

[2d] MD Tax-Prop Code § 7-237 (2016)

[2e] Phone conversation with representative at Charles County Treasury Department.

[3a],[3c] Ohio rates estimated based on the average effective tax rates from Trumbull and Carroll counties. For Trumbull county see:
http://auditor.co.trumbull.oh.us/pdfs/2020%20RATE%20OF%20TAXATION.pdf
For Caroll County see:
http://www.carrollcountyauditor.us/auditorsadvisory/Rates%20of%20Taxation%202020.pdf

[3b],[3d] Assessment ratios for real property and personal property taxes found on pages 124 and 129:
http://www.tax.ohio.gov/Portals/0/communications/publications/annual_reports/2016AnnualReport/2016AnnualReport.pdf

[3e] Depreciation schedules for utility assets found in Form U-El by Ohio Department of Taxation:
http://www.tax.ohio.gov/portals/0/forms/public_utility_excise/2017/PUE_UEL.xls

[4a] Pennsylvania county tax rates for RTO based on the county of Lawrence, available at:
https://lawrencecountypa.gov/wp-content/uploads/2021/07/2021-millage.pdf

[4b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf

[4c]-[4e] According to *Pennsylvania Legislator's Municipal Deskbook Taxation & Finance (Real Estate Assessment Process, pg. 1)* , only real estate tax assessed by local governments.

[5a] Pennsylvania county tax rates for WMAAC based on average effective tax rate between Luzerne, Lycoming, and Bradford counties:
https://www.luzernecounty.org/DocumentCenter/View/26403/2021-MILLAGES-JULY
https://www.lyco.org/Portals/1/Assessment/Documents/2021%20Millage.pdf?ver=2021-01-29-090920-517
https://bradfordcountypa.org/wp-content/uploads/2021/09/Bradford-County-Mill-Rates.pdf

[5b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf
Note assessment ratios above 100% are capped at 100% in our calculations.

[5c]-[5e] According to Pennsylvania Legislator's Municipal Deskbook Taxation & Finance (Real Estate Assessment Process, pg. 1), only real estate tax assessed by local governments.

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## Introduction

This document provides information for PJM stakeholders regarding the results of the 2024/2025 Reliability Pricing Model (RPM) Base Residual Auction (BRA).

In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing the following reliability-based constraints on the location and type of capacity that can be committed:

- Internal PJM locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA.
- Total cleared summer-period sell offers must exactly equal total cleared winter-period sell offers across the entire RTO to ensure that seasonal CP sell offers clear to form annual CP commitments.

The auction clearing process commits capacity resources to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing and enforcing these reliability-based constraints. The clearing solution may be required to commit capacity resources out-of-merit order but again in a least-cost manner to ensure that all of these constraints are respected. In those cases where one or more of the constraints results in out-of-merit commitment in the auction solution, resource clearing prices will be reflective of the price of resources selected out of merit order to meet the necessary requirements.

An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC, and MAAC. An LDA not otherwise qualifying under the above three tests may also be modeled if PJM finds that the LDA is determined to be likely to have a Locational Price Adder based on historic offer price levels or if such LDA is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards.

As a result of the above criteria, MAAC, EMAAC, SWMAAC, PSEG, PS-NORTH, DPL-SOUTH, PEPCO, ATSI, ATSI-Cleveland, COMED, BGE, PL, DAY and DEOK were modeled as LDAs in the 2024/2025 RPM Base Residual Auction. A Locational Price Adder represents the difference in Resource Clearing Prices for the Capacity Performance product between a resource in a constrained LDA and the immediate higher level LDA.

**Executive Summary**

The 2024/2025 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 140,415.8 MW of unforced capacity in the RTO from non-energy efficiency annual, summer-period, and winter-period resources representing a 21.7% reserve margin. Energy Efficiency (EE) resources are excluded from this calculation because their impact is reflected in a lower load forecast and therefore not used to meet the Reliability Requirement. The reserve margin for the entire RTO, which includes Fixed Resource Requirement (FRR) is 20.4% or 5.7 percentage points higher than the target reserve margin of 14.7%. These results are similar to the 2023/2024 BRA.

Supply offered into the RPM capacity market, excluding EE Resources, declined 2,197.7 MW from 151,143.4 MW in the 2023/2024 BRA to 148,945.7 MW in the 2024/2025 BRA. This is the third BRA in a row where the total Capacity offered from non-EE resources has declined. Further, the number of constrained LDAs increased from 3 constrained LDAs in the 2023/2024 BRA to 5 constrained LDAs in the 2024/2025 BRA. This reflects tighter supply and demand conditions in those locations. The total amount of capacity, excluding EE Resources, in RPM that cleared increased 542.2 MW from 139,873.6 MW in the 2023/2024 BRA to 140,415.8 MW in the 2024/2025 BRA.

The RTO as a whole failed the Market Structure Test (i.e., the Three-Pivotal Supplier Test), resulting in the application of market power mitigation to all Existing Generation Capacity Resources. Mitigation was applied to a supplier's existing generation resources resulting in utilizing the lesser of the supplier's approved Market Seller Offer Cap for such resource or the supplier's submitted offer price for such resource in the RPM Auction clearing.

Resource Clearing Prices (RCPs) for the 2024/2025 BRA for CP Resources located in the rest of RTO declined from $34.13/MW-day to $28.92/MW-day. The number of constrained LDAs increase from 3 LDAs (MAAC, BGE, DPL-S) to 5 LDAs (MAAC, BGE, DPL-S, EMAAC and DEOK). MAAC prices remained the same at $49.49/MW-day while prices for the other 4 constrained LDAs increased: EMAAC increased from $49.49/MW-day to $54.95/MW-day, DPL-S increased from $69.95/MW-day to $90.64/MW-day, BGE increased by $69.95/MW-day to $73.00/MW-day, and DEOK increased from $34.13/MW-day to $96.24/MW-day.

For the 24/25 BRA, total offered and FRR committed resources (includes annual, summer period and winter period) was 1,384 MW lower than in the prior BRA. Key changes in offered supply include:

- Decrease in Coal (-2,050 MW), Water/Hydro (-237 MW), DR (-318 MW) and Wind (-212 MW)
- Increase in Solar (+1,290 MW) and Natural Gas (+252 MW)

For the 24/25 BRA, total cleared and FRR committed resources (includes annual, summer period and winter period) was 1,356 MW higher than in the prior BRA. Key changes in cleared and FRR committed resources include:

- Decrease in DR (-451 MW), Water/Hydro (-237 MW), and Nuclear (-331 MW) and Coal (-278 MW)
- Increase in Natural Gas (+1,615 MW), Solar (+1,297 MW)

The following is a list of new market rules or planning parameter changes that may have impacted the auction results:

- The auction results were postponed and then finalized based on FERC order (ER23-729-000), issued on Feb. 21.
- Planning parameters (please see the Planning Parameters Report for various changes:
  - netCONE values used to determine the VRR curve were marginally higher (+6.2% to +7.2%) based on the normal escalation process.
  - RTO Reliability Requirement increased by only 236 MW from 131,820 MW to 132,056 MW (or 0.2%) although there were some significant LDA Reliability Requirement changes.

Note: This BRA was conducted under a compressed auction schedule where the auction occurred ~17 months prior to the start of the delivery year. A typical BRA is held more than three years before the start of the delivery year. The prior BRA was conducted under the same compressed auction schedule.

**Detailed Report**

Table 1 contains a summary of the RTO clearing prices, cleared unforced capacity, and implied cleared reserve margins for the 2007/2008 through 2024/2025 RPM BRAs. The Reserve Margin presented in Table 1 represents the percentage of installed capacity cleared in RPM and committed by FRR entities in excess of the RTO load (including load served under the Fixed Resource Requirement alternative). The reserve margin for the entire RTO is 20.4%, or 5.7 percentage points higher than the target reserve margin of 14.7%, when the Fixed Resource Requirement (FRR) load and resources are considered. The reserve margin for the RTO was only 0.1% points higher than the prior BRA.

**Table 1 - RPM Base Residual Auction Resource Clearing Price Results in the RTO**

| | Auction Results | | |
|---|---|---|---|
| Delivery Year | Resource Clearing Price | Cleared UCAP (MW) | Reserve Margin |
| 2007/2008 | $ 40.80 | 129,409.2 | 19.1% |
| 2008/2009 | $ 111.92 | 129,597.6 | 17.4% |
| 2009/2010 | $ 102.04 | 132,231.8 | 17.6% |
| 2010/2011 | $ 174.29 | 132,190.4 | 16.4% |
| 2011/2012[1] | $ 110.00 | 132,221.5 | 17.9% |
| 2012/2013 | $ 16.46 | 136,143.5 | 20.5% |
| 2013/2014[2] | $ 27.73 | 152,743.3 | 19.7% |
| 2014/2015[3] | $ 125.99 | 149,974.7 | 18.8% |
| 2015/2016[4] | $ 136.00 | 164,561.2 | 19.3% |
| 2016/2017[5] | $ 59.37 | 169,159.7 | 20.3% |
| 2017/2018 | $ 120.00 | 167,003.7 | 19.7% |
| 2018/2019 | $ 164.77 | 166,836.9 | 19.8% |
| 2019/2020 | $ 100.00 | 167,305.9 | 22.4% |
| 2020/2021[6] | $ 76.53 | 165,109.2 | 23.3% |
| 2021/2022 | $ 140.00 | 163,627.3 | 21.5% |
| 2022/2023 | $ 50.00 | 144,477.3 | 19.9% |
| 2023/2024 | $ 34.13 | 144,870.6 | 20.3% |
| 2024/2025 | $ 28.92 | 147,478.9 | 20.4% |

1) 2011/2012 BRA was conducted without Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone
6) Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers
7) Reserve Margin includes FRR+RPM (Total ICAP/Total Peak-1)

Table 2 below provides a summary of the clearing prices by Constrained LDA. Resource Clearing Prices (RCPs) for the 2024/2025 BRA for CP Resources located in the rest of RTO declined from $34.13/MW-day to $28.92/MW-day. The number of constrained LDAs increased from 3 LDAs (MAAC, BGE, DPL-S) to 5 LDAs (MAAC, BGE, DPL-S, EMAAC and DEOK). MAAC prices remained the same at $49.49/MW-day while price for the other 4 constrained LDAs increased: EMAAC increased from $49.49/MW-day to $54.95/MW-day, DPL-S increased from $69.95/MW-day to $90.64/MW-day, BGE increased by $69.95/MW-day to $73.00/MW-day, and DEOK increased from $34.13/MW-day to $96.24/MW-day.

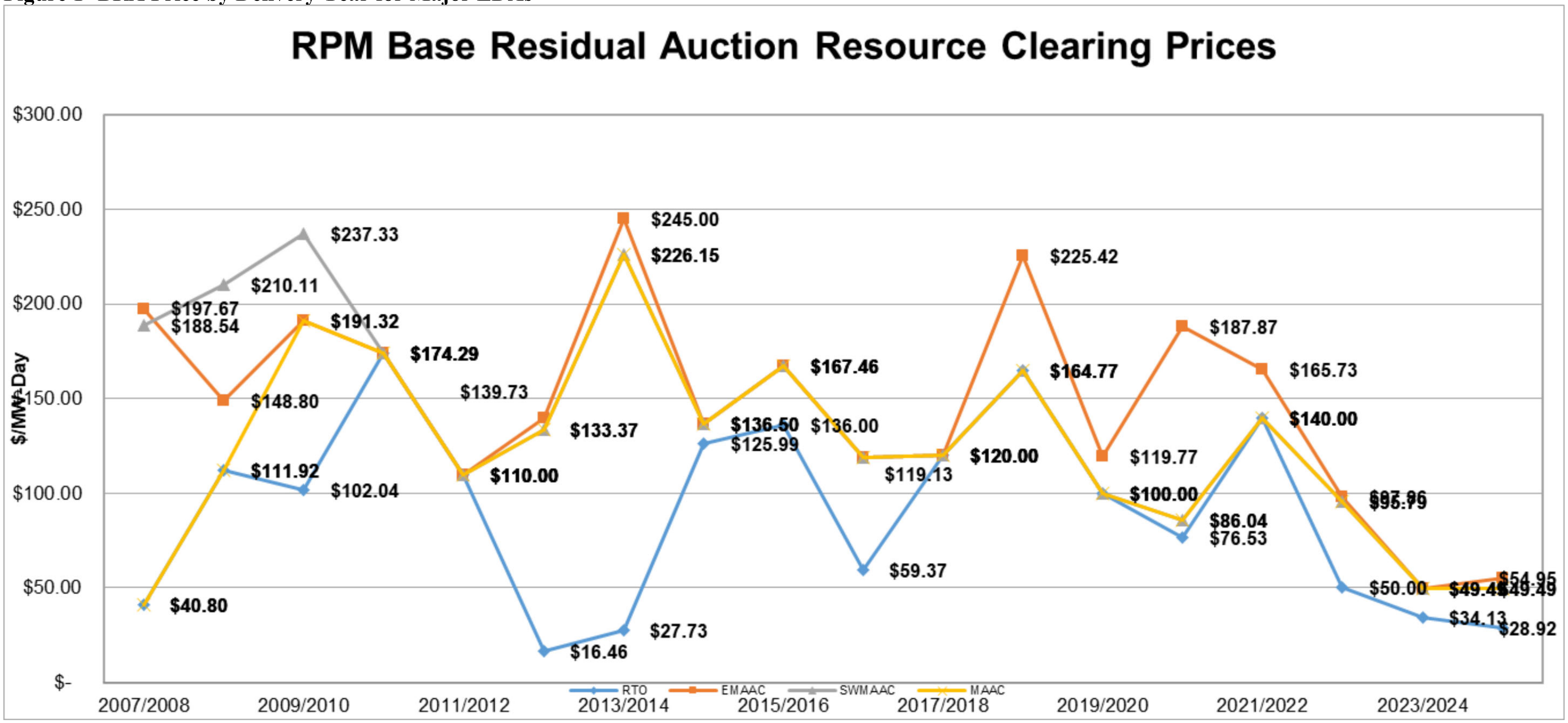
Since the MAAC, EMAAC, DPL-South, BGE and DEOK were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDA for the 2024/2025 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.

**Table 2 – Comparison of BRA Clearing Price by Delivery Year by Constrained LDA**

| | | BRA Resource Clearing Prices ($/MW-day)") | | | | | |
|---|---|---|---|---|---|---|---|
| Capacity Type | BRA | Rest of RTO | MAAC | EMAAC | DPL-SOUTH | BGE | DEOK |
| Capacity Performance | 2024/2025 | $28.92 | $49.49 | $54.95 | $90.64 | $73.00 | $96.24 |
| Capacity Performance | 2023/2024 | $34.13 | $49.49 | $49.49 | $69.95 | $69.95 | $34.13 |

Figure 1 represents the trend in BRA Capacity price by Delivery Year for RTO, EMAAC, SWMAAC and MAAC. RTO prices were down from $34.13/MW-day to $28.92/MW-day. MAAC prices remained the same and EMAAC prices were up from $49.49/MW-day to $54.95/MW-day. SWMAAC was not constrained and had the same prices as MAAC.

**Figure 1- BRA Price by Delivery Year for Major LDAs**




* 2014/2015 through 2024/2025 Prices reflect the Annual Resource Clearing Prices.

Table 3 provides the offered and cleared MWs and associated Prices by LDA. This table provides an indication of how much supply did not clear for each LDA. For example, DPL-South had only 26.9 MW of additional supply that did not clear but it was for summer only resources that could not be matched with available Winter MWs and therefore did not clear. EMAAC, DPL-South, PSEG, PSEG-North, and DEOK all had less than 5% MW offered in excess of cleared MW.

**Table 3 - Offered and Cleared MWs and associate Prices by LDA**

| Auction Results | RTO | MAAC | SWMAAC | PEPCO | BGE | EMAAC | DPL-SOUTH | PSEG | PS-NORTH | ATSI | ATSI-CLEVELAND | PPL | COMED | DAY | DEOK |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Offered MW (UCAP)* | 157,362.7 | 68,615.8 | 8,973.1 | 3,651.1 | 2,942.1 | 31,661.6 | 1,448.9 | 6,362.3 | 3,571.6 | 10,351.3 | 2,015.5 | 10,750.3 | 27,502.8 | 1,052.9 | 2,115.9 |
| Cleared MW (UCAP)** | 147,478.9 | 64,200.8 | 8,472.5 | 3,421.0 | 2,671.6 | 30,670.5 | 1,422.0 | 6,111.8 | 3,470.8 | 9,716.7 | 1,885.2 | 10,004.5 | 25,152.0 | 985.4 | 2,060.0 |
| System Marginal Price | $28.92 | $28.92 | $28.92 | $28.92 | $28.92 | $28.92 | $28.92 | $28.92 | $28.92 | $28.92 | $28.92 | $28.92 | $28.92 | $28.92 | $28.92 |
| Locactional Price Adder*** | $0.00 | $20.57 | $0.00 | $0.00 | $23.51 | $5.46 | $35.69 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $67.32 |
| RCP for Capacity Performance Resources | $28.92 | $49.49 | $49.49 | $49.49 | $73.00 | $54.95 | $90.64 | $54.95 | $54.95 | $28.92 | $28.92 | $49.49 | $28.92 | $28.92 | $96.24 |

* Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers
** Cleared MW values include Annual and matched Seasonal Capacity Performance sell offers w ithin the LDA
*** Locational Price Adder is w ith respect to the immediate parent LDA

As seen in the table below, the 2024/2025 BRA procured 328.5 MW of capacity from new generation and 173.8 MW from uprates to existing or planned generation. The quantity of new generation is significantly down from last BRA where there was 3,329.7 MW of new generation. The quantity of capacity procured from external Generation Capacity Resources in the 2024/2025 BRA is 1,397.6 MW. All external generation capacity that cleared in the 2024/2025 BRA are Prior Capacity Import Limit (CIL) Exception External Resources[1] that qualify for an exception for the 2024/2025 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138. The total quantity of DR procured in the 2024/2025 BRA is 7,992.7 MW, and the total quantity of EE procured in the 2024/2025 BRA is 7,668.7 MW.

[1] A Prior CIL Exception Resource is an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in Article 1 of the Reliability Assurance Agreement or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided to the definition of Capacity Import Limit.

**Table 4- Cleared MWs (UCAP) by Type by Delivery Year**

| BRA Delivery Year | New Generation | Generation Uprates | Imports | Demand Response | Energy Efficiency |
|---|---|---|---|---|---|
| **2024/2025** | 328.5 | 173.8 | 1,397.6 | 7,992.7 | 7,668.7 |
| **2023/2024** | 3,329.7 | 404.8 | 1,396.6 | 8,096.2 | 5,471.1 |
| **2022/2023** | 4,843.6 | 1,210.3 | 1,558.0 | 8,811.9 | 4,810.6 |
| **2021/2022** | 893.0 | 508.3 | 4,051.8 | 11,125.8 | 2,832.0 |
| **2020/2021** | 2,389.3 | 434.5 | 3,997.2 | 7,820.4 | 1,710.2 |
| **2019/2020** | 5,373.6 | 155.6 | 3,875.9 | 10,348.0 | 1,515.1 |
| **2018/2019** | 2,954.3 | 587.6 | 4,687.9 | 11,084.4 | 1,246.5 |
| **2017/2018** | 5,927.4 | 339.9 | 4,525.5 | 10,974.8 | 1,338.9 |
| **2016/2017** | 4,281.6 | 1,181.3 | 7,482.7 | 12,408.1 | 1,117.3 |
| **2015/2016** | 4,898.9 | 447.4 | 3,935.3 | 14,832.8 | 922.5 |
| **2014/2015** | 415.5 | 341.1 | 3,016.5 | 14,118.4 | 822.1 |

*All MW Values are in UCAP Terms

Table 5 contains a summary of the RTO resources for each cleared BRA from 2008/2009 through the 2024/2025 Delivery Years. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 209,800.5 MW of installed capacity was eligible to be offered into the 2024/2025 Base Residual Auction, with 1,617.1 MW from external resources. As illustrated in Table 5, the amount of capacity exports in the 2024/2025 auction increased slightly to 1,522.7 MW from that of the previous auction and FRR commitments increased to 34.584.2 MW.

A total of 154,062.3 MW of Generation and DR capacity was offered into the Base Residual Auction. This is a decrease of 1,791.6 MW from that which was offered into the 2023/2024 BRA. EE resources are already included in the forecast and therefore do not help meet the reliability requirement. A total of 48,009.3 MW was eligible, but not offered due to either (1) inclusion in an FRR Capacity Plan, (2) export of the resource, (3) having been excused from offering into the auction or (4) are not required to offer into the auction and elected to not offer into the auction. Resources were excused from the must offer requirement for the following reasons: approved retirement requests or external sale of capacity. Resources with approved removal of capacity status requests also did not have a capacity must offer requirement.

## Table 5 – Total RTO Resources (RPM + FRR) offered vs unoffered by Resource Type

| | RTO[1] | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Auction Supply (all values in ICAP)** | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012[2] | 2012/2013 | 2013/2014[3] | 2014/2015[4] | 2015/2016[5] | 2016/2017[6] | 2017/2018 | 2018/2019 | 2019/2020 | 2020/2021 | 2021/2022 | 2022/2023 | 2023/2024 | 2024/2025 |
| Internal PJM Capacity | 166,037.9 | 167,026.3 | 168,457.3 | 169,241.6 | 179,791.2 | 195,633.4 | 199,375.5 | 207,559.1 | 208,098.0 | 202,477.4 | 203,300.6 | 207,579.6 | 207,555.1 | 211,625.2 | 207,339.8 | 204,006.6 | 208,183.4 |
| Imports Offered | 2,612.0 | 2,563.2 | 2,982.4 | 6,814.2 | 4,152.4 | 4,766.1 | 7,620.2 | 4,649.7 | 8,412.2 | 6,300.9 | 5,724.6 | 4,821.4 | 5,440.5 | 4,725.0 | 1,649.1 | 1,601.2 | 1,617.1 |
| **Total Eligible RPM Capacity** | **168,649.9** | **169,589.5** | **171,439.7** | **176,055.8** | **183,943.6** | **200,399.5** | **206,995.7** | **212,208.8** | **216,510.2** | **208,778.3** | **209,025.2** | **212,401.0** | **212,995.6** | **216,350.2** | **208,988.9** | **205,607.8** | **209,800.5** |
| Exports / Delistings | 4,205.8 | 2,240.9 | 3,378.2 | 3,389.2 | 2,783.9 | 2,624.5 | 1,230.1 | 1,218.8 | 1,218.8 | 1,223.2 | 1,313.4 | 1,318.2 | 1,319.8 | 1,319.8 | 1,525.3 | 1,518.9 | 1,522.7 |
| FRR Commitments | 24,953.5 | 25,316.2 | 26,305.7 | 25,921.2 | 26,302.1 | 25,793.1 | 33,612.7 | 15,997.9 | 15,576.6 | 15,776.1 | 15,793.0 | 15,385.3 | 13,931.6 | 13,657.4 | 33,297.1 | 33,500.7 | 34,584.2 |
| Excused | 722.0 | 1,121.9 | 1,290.7 | 1,580.0 | 1,732.2 | 1,825.7 | 3,255.2 | 8,712.9 | 8,524.0 | 4,305.3 | 2,348.4 | 1,454.5 | 7,826.4 | 8,923.8 | 1,960.0 | 9,714.6 | 11,902.4 |
| **Total Eligible RPM Capacity: Excused** | **29,881.3** | **28,679.0** | **30,974.6** | **30,890.4** | **30,818.2** | **30,243.3** | **38,098.0** | **25,929.6** | **25,319.4** | **21,304.6** | **19,454.8** | **18,158.0** | **23,077.8** | **23,901.0** | **36,782.4** | **44,734.2** | **48,009.3** |
| **Remaining Eligible RPM Capacity** | **138,768.6** | **140,910.5** | **140,465.1** | **145,165.4** | **153,125.4** | **170,156.2** | **168,897.7** | **186,279.2** | **191,190.8** | **187,473.7** | **189,570.4** | **194,243.0** | **189,917.8** | **192,449.2** | **172,206.5** | **160,873.6** | **161,791.2** |
| Generation Offered | 138,076.7 | 140,003.6 | 139,529.5 | 143,568.1 | 142,957.7 | 156,894.1 | 153,048.1 | 166,127.8 | 176,145.3 | 175,329.5 | 177,592.1 | 181,866.4 | 178,807.1 | 178,823.5 | 157,872.2 | 146,571.7 | 144,741.2 |
| DR Offered | 691.9 | 906.9 | 935.6 | 1,597.3 | 9,535.4 | 12,528.7 | 15,043.1 | 19,243.6 | 13,932.9 | 10,855.2 | 10,772.8 | 10,859.2 | 9,047.8 | 10,911.9 | 9,677.9 | 9,282.2 | 9,321.1 |
| EE Offered | 0.0 | 0.0 | 0.0 | 0.0 | 632.3 | 733.4 | 806.5 | 907.8 | 1,112.6 | 1,289.0 | 1,205.5 | 1,517.4 | 2,062.9 | 2,713.8 | 4,656.4 | 5,019.7 | 7,728.9 |
| **Total Eligible RPM Capacity Offered** | **138,768.6** | **140,910.5** | **140,465.1** | **145,165.4** | **153,125.4** | **170,156.2** | **168,897.7** | **186,279.2** | **191,190.8** | **187,473.7** | **189,570.4** | **194,243.0** | **189,917.8** | **192,449.2** | **172,206.5** | **160,873.6** | **161,791.2** |
| **Total Eligible RPM Capacity Unoffered** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** | **0.0** |

[1]RTO numbers include all LDAs.
[2]All generation in the Duquesne zone is considered external to PJM for the 2011/2012 BRA.
[3]2013/2014 includes ATSI zone and generation
[4]2014/2015 includes Duke zone and generation
[5]2015/2016 includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
[6]2016/2017 includes EKPC zone

Table 6 shows the Generation, DR, and EE Resources Offered and Cleared in the RTO translated into Unforced Capacity (UCAP) MW amounts. Participants' sell offer EFORd values were used to translate the generation installed capacity values into unforced capacity (UCAP) values. DR sell offers and EE sell offers were converted into UCAP using the appropriate Forecast Pool Requirement (FPR), when applicable, for the Delivery Year.

Total offered Gen and DR used to meet the reliability requirement declined from 151,143.4 MW to 148,945.7 MWs. That is a 2,197.7 MW decrease in the amount of supply in the Capacity Market.

**Table 6 - Capacity Resource offered and cleared by type by Delivery Year**

| | RTO* | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Auction Results** | **2008/2009** | **2009/2010** | **2010/2011** | **2011/2012** | **2012/2013** | **2013/2014** | **2014/2015** | **2015/2016** | **2016/2017** | **2017/2018** | **2018/2019** | **2019/2020** | **2020/2021** | **2021/2022** | **2022/2023** | **2023/2024** | **2024/2025** |
| Generation Offered | 131,164.8 | 132,614.2 | 132,124.8 | 136,067.9 | 134,873.0 | 147,188.6 | 144,108.8 | 157,691.1 | 168,716.0 | 166,204.8 | 166,909.6 | 172,071.2 | 171,262.3 | 171,663.2 | 152,128.6 | 141,026.7 | 138,799.3 |
| DR Offered | 715.8 | 936.8 | 967.9 | 1,652.4 | 9,847.6 | 12,952.7 | 15,545.6 | 19,956.3 | 14,507.2 | 11,293.7 | 11,675.5 | 11,818.0 | 9,846.7 | 11,886.8 | 10,513.0 | 10,116.7 | 10,146.4 |
| EE Offered | - | - | - | - | 652.7 | 756.8 | 831.9 | 940.3 | 1,156.8 | 1,340.0 | 1,306.1 | 1,650.3 | 2,242.5 | 2,954.8 | 5,056.8 | 5,471.1 | 8,417.0 |
| **Total Offered** | **131,880.6** | **133,551.0** | **133,092.7** | **137,720.3** | **145,373.3** | **160,898.1** | **160,486.3** | **178,587.7** | **184,380.0** | **178,838.5** | **179,891.2** | **185,539.5** | **183,351.5** | **186,504.8** | **167,698.4** | **156,614.5** | **157,362.7** |
| Generation Cleared | 129,061.4 | 131,338.9 | 131,251.5 | 130,856.6 | 128,527.4 | 142,782.0 | 135,034.2 | 148,805.9 | 155,634.3 | 154,690.0 | 154,506.0 | 155,442.8 | 155,976.5 | 150,385.0 | 131,541.6 | 131,777.4 | 132,423.1 |
| DR Cleared | 536.2 | 892.9 | 939.0 | 1,364.9 | 7,047.2 | 9,281.9 | 14,118.4 | 14,832.8 | 12,408.1 | 10,974.8 | 11,084.4 | 10,348.0 | 7,820.4 | 11,125.8 | 8,811.9 | 8,096.2 | 7,992.7 |
| EE Cleared | 0.0 | 0.0 | 0.0 | 0.0 | 568.9 | 679.4 | 822.1 | 922.5 | 1,117.3 | 1,338.9 | 1,246.5 | 1,515.1 | 1,710.2 | 2,832.0 | 4,810.6 | 5,471.1 | 7,668.7 |
| **Total Cleared** | **129,597.6** | **132,231.8** | **132,190.5** | **132,221.5** | **136,143.5** | **152,743.3** | **149,974.7** | **164,561.2** | **169,159.7** | **167,003.7** | **166,836.9** | **167,305.9** | **165,109.2** | **163,627.3** | **144,477.3** | **144,870.6** | **147,478.9** |
| Uncleared | 2,283.0 | 1,319.2 | 902.2 | 5,498.8 | 9,229.8 | 8,154.8 | 10,511.6 | 14,026.5 | 15,220.3 | 11,834.8 | 13,054.3 | 18,233.6 | 18,242.3 | 22,877.5 | 23,221.1 | 11,743.9 | 9,883.8 |

* RTO numbers include all LDAs

** UCAP calculated using sell offer EFORd for Generation Resources. DR and EE UCAP values include appropriate FPR and DR Factor.

***Starting 2020/2021: Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers

***Starting 2020/2021: Total RTO Cleared MW value includes Annual and matched Seasonal Capacity Performance sell offers

Table 7 shows the offered and cleared MWs by Resource type for RPM over the last 4 Delivery Years. Table 8 provides the change in MWs by Delivery Year to illustrate the trend over the last four BRAs. Table 9 shows the offered and cleared MWs by Resource type for RPM plus FRR commitments over the last four Delivery Years. Table 10 provides the change in MWs by Delivery Year to illustrate the trend over the last four BRAs for overall supply to RPM and FRR areas. Table 9 and 10 provide a comprehensive picture of the trend in Supply since FRR participation has changed over the last four BRAs and resources may change from to FRR or RPM. Table 10 indicates that total RPM offered and FRR committed supply is down over the last three BRAs. Since Energy Efficiency is already included in the load forecast it is not used to meet the Reliability Requirement and therefore separated from the Grand Totals in the tables to provide a more accurate picture of the Resources that will be used to meet the Reliability Requirement.

For the 24/25 BRA, total offered and FRR committed resources (includes annual, summer period and winter period) was 1,384 MW lower than in the prior BRA. Key changes in offered supply include:

- Decrease in Coal (-2,050 MW), Water/Hydro (-237 MW), DR (-318 MW) and Wind (-212 MW)
- Increase in Solar (+1,290 MW) and Natural Gas (+252 MW)

For the 24/25 BRA, total cleared and FRR committed resources (includes annual, summer period and winter period) was 1,356 MW higher than in the prior BRA. Key changes in cleared and FRR committed resources include:

- Decrease in DR (-451 MW), Water/Hydro (-237 MW), and Nuclear (-331 MW) and Coal (-278 MW)
- Increase in Natural Gas (+1,615 MW), Solar (+1,297 MW)

Table 7 -Offered and Cleared MWs by Type for RPM for previous BRAs

| Delivery Year<br>Data | 2021/2022 Offered UCAP | 2021/2022 Cleared UCAP | 2022/2023 Offered UCAP | 2022/2023 Cleared UCAP | 2023/2024 Offered UCAP | 2023/2024 Cleared UCAP | 2024/2025 Offered UCAP | 2024/2025 Cleared UCAP |
|---|---|---|---|---|---|---|---|---|
| Coal | 44,936 | 39,022 | 33,935 | 27,411 | 26,968 | 21,615 | 25,060 | 21,478 |
| Distillate Oil (No.2) | 3,254 | 3,155 | 2,977 | 2,696 | 2,684 | 2,645 | 2,592 | 2,490 |
| Gas | 77,514 | 74,814 | 75,526 | 69,292 | 74,552 | 70,978 | 73,714 | 71,504 |
| Nuclear | 30,561 | 19,918 | 26,855 | 21,050 | 26,365 | 26,365 | 26,024 | 25,818 |
| Oil | 5,218 | 3,955 | 2,419 | 2,271 | 1,901 | 1,820 | 2,150 | 1,876 |
| Solar | 625 | 570 | 2,049 | 1,512 | 1,878 | 1,868 | 2,768 | 2,765 |
| Water | 6,708 | 6,229 | 4,324 | 4,157 | 3,677 | 3,677 | 3,715 | 3,715 |
| Wind | 1,442 | 1,417 | 2,484 | 1,728 | 1,486 | 1,294 | 1,272 | 1,272 |
| Battery | - | - | - | - | - | - | - | - |
| Hybrid | - | - | - | - | - | - | - | - |
| Other | 1,406 | 1,305 | 1,077 | 1,040 | 1,005 | 1,005 | 1,001 | 1,001 |
| Demand Response | 11,887 | 11,126 | 10,513 | 8,812 | 10,117 | 8,096 | 10,146 | 7,993 |
| Aggregate Resource | - | - | 484 | 386 | 511 | 511 | 503 | 503 |
| Grand Total (w/o EE) | 183,550 | 161,511 | 162,642 | 140,354 | 151,143 | 139,874 | 148,946 | 140,416 |
| Energy Efficiency | 2,955 | 2,832 | 5,057 | 4,811 | 5,471 | 5,471 | 8,417 | 7,669 |
| Grand Total (w/EE) | 186,505 | 164,343 | 167,698 | 145,164 | 156,615 | 145,345 | 157,363 | 148,085 |

The table shows the UCAP MW quantities that offered and cleared in the BRA of each DY

Notes:

- Offered and Cleared MW quantities include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.
- Aggregate Resource category includes aggregates resources of different resource types
- Other = Kerosene, Other Gas, Other Liquid, Other Solid, Wood
- Starting 2020/2021:  Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance

**Table 8 - Change in Offered and Cleared MWs by Type for RPM for previous BRAs**

| | Change in Offered MWs | | | Change in Cleared MWs | | |
|---|---|---|---|---|---|---|
| Data | 2022/2023-2021/2022 | 2023/2024-2022/2023 | 2024/2025-2023/2024 | 2022/2023-2021/2022 | 2023/2024-2022/2023 | 2024/2025-2023/2024 |
| Coal | (11,001) | (6,967) | (1,908) | (11,612) | (5,796) | (136) |
| Distillate Oil (No.2) | (278) | (292) | (92) | (460) | (51) | (155) |
| Gas | (1,988) | (974) | (837) | (5,522) | 1,685 | 526 |
| Nuclear | (3,706) | (490) | (341) | 1,132 | 5,315 | (547) |
| Oil | (2,799) | (518) | 249 | (1,684) | (451) | 57 |
| Solar | 1,424 | (171) | 890 | 942 | 357 | 897 |
| Water | (2,383) | (647) | 37 | (2,072) | (480) | 37 |
| Wind | 1,042 | (998) | (214) | 311 | (434) | (22) |
| Battery | - | - | - | - | - | - |
| Hybrid | - | - | - | - | - | - |
| Other | (330) | (71) | (4) | (265) | (34) | (4) |
| Demand Response | (1,374) | (396) | 30 | (2,314) | (716) | (103) |
| Aggregate Resource | 484 | 27 | (7) | 386 | 125 | (7) |
| Grand Total (w/o EE) | (20,908) | (11,498) | (2,198) | (21,157) | (480) | 542 |
| Energy Efficiency | 2,102 | 414 | 2,946 | 1,979 | 660 | 2,198 |

Table 9 - Offered and Cleared MWs by Type for RPM and committed FRR for previous BRAs

| Delivery Year<br>Data | 2021/2022 Offered UCAP | 2021/2022 Cleared UCAP | 2022/2023 Offered UCAP | 2022/2023 Cleared UCAP | 2023/2024 Offered UCAP | 2023/2024 Cleared UCAP | 2024/2025 Offered UCAP | 2024/2025 Cleared UCAP |
|---|---|---|---|---|---|---|---|---|
| Coal | 53,444 | 47,531 | 45,754 | 39,230 | 37,164 | 31,811 | 35,114 | 31,532 |
| Distillate Oil (No.2) | 3,254 | 3,155 | 3,178 | 2,897 | 2,894 | 2,855 | 2,776 | 2,674 |
| Gas | 78,863 | 76,164 | 85,562 | 79,329 | 85,217 | 81,643 | 85,469 | 83,258 |
| Nuclear | 32,541 | 21,898 | 31,944 | 26,140 | 31,960 | 31,960 | 31,835 | 31,629 |
| Oil | 5,218 | 3,955 | 2,674 | 2,527 | 2,350 | 2,269 | 2,493 | 2,220 |
| Solar | 644 | 589 | 2,633 | 2,096 | 2,945 | 2,935 | 4,234 | 4,232 |
| Water | 7,239 | 6,760 | 6,917 | 6,749 | 6,375 | 6,375 | 6,137 | 6,137 |
| Wind | 1,551 | 1,526 | 2,595 | 1,839 | 1,608 | 1,416 | 1,396 | 1,396 |
| Battery | - | - | - | - | 16 | 16 | 36 | 36 |
| Hybrid | - | - | - | - | - | - | 10 | 10 |
| Other | 1,419 | 1,318 | 1,205 | 1,168 | 1,185 | 1,185 | 1,153 | 1,153 |
| Demand Response | 12,114 | 11,353 | 10,604 | 8,903 | 10,652 | 8,631 | 10,334 | 8,180 |
| Aggregate Resource | - | - | 484 | 386 | 511 | 511 | 503 | 503 |
| Grand Total (w/o EE) | 196,288 | 174,249 | 193,551 | 171,263 | 182,875 | 171,605 | 181,491 | 172,961 |
| Energy Efficiency | 2,955 | 2,832 | 5,057 | 4,811 | 5,471 | 5,471 | 8,417 | 7,669 |
| Grand Total (w/EE) | 199,243 | 177,081 | 198,608 | 176,073 | 188,346 | 177,076 | 189,908 | 180,630 |

The table shows the UCAP MW quantities that offered and cleared in the BRA of each DY plus the UCAP MW committed to FRR Capacity Plans

Notes:

- Offered and Cleared MW quantities include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.
- Aggregate Resource category includes aggregates resources of different resource types
- Other = Kerosene, Other Gas, Other Liquid, Other Solid, Wood
- Starting 2020/2021: Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance

**Table 10 - Change in Offered and Cleared MWs by Type for RPM and committed FRR for previous BRAs**

| | Change in Offered MWs | | | Change in Cleared MWs | | |
|---|---|---|---|---|---|---|
| Data | 2022/2023-2021/2022 | 2023/2024-2022/2023 | 2024/2025-2023/2024 | 2022/2023-2021/2022 | 2023/2024-2022/2023 | 2024/2025-2023/2024 |
| Coal | (7,690) | (8,590) | (2,050) | (8,301) | (7,419) | (278) |
| Distillate Oil (No.2) | (77) | (283) | (118) | (259) | (42) | (181) |
| Gas | 6,699 | (346) | 252 | 3,165 | 2,314 | 1,615 |
| Nuclear | (596) | 16 | (125) | 4,242 | 5,820 | (331) |
| Oil | (2,544) | (325) | 143 | (1,429) | (258) | (49) |
| Solar | 1,989 | 311 | 1,290 | 1,507 | 839 | 1,297 |
| Water | (322) | (542) | (237) | (11) | (374) | (237) |
| Wind | 1,044 | (988) | (212) | 314 | (423) | (20) |
| Battery | - | 16 | 20 | - | 16 | 20 |
| Hybrid | - | - | 10 | - | - | 10 |
| Other | (214) | (20) | (32) | (150) | 17 | (32) |
| Demand Response | (1,510) | 48 | (318) | (2,451) | (272) | (451) |
| Aggregate Resource | 484 | 27 | (7) | 386 | 125 | (7) |
| Grand Total (w/o EE) | (2,738) | (10,676) | (1,384) | (2,987) | 343 | 1,356 |
| Energy Efficiency | 2,102 | 414 | 2,946 | 1,979 | 660 | 2,198 |

## Capacity Import Participation

The quantity of capacity imports cleared in the 2024/2025 BRA were 1,397.6 MW (UCAP). The majority of the imports are from resources located in regions west of the PJM RTO. All external generation capacity that has cleared are Prior Capacity Import Limit (CIL) Exception External Resources that qualify for an exception for the 2024/2025 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

**Table 11 - Capacity Imports (UCAP) Offered and Cleared by Region**

| | External Source Zones | | | | | |
|---|---|---|---|---|---|---|
| | NORTH | WEST 1 | WEST 2 | SOUTH 1 | SOUTH 2 | Total |
| Offered MW (UCAP) | 220.8 | 0.0 | 807.9 | 238.0 | 260.4 | **1,527.1** |
| Cleared MW (UCAP) | 220.8 | 0.0 | 678.4 | 238.0 | 260.4 | **1,397.6** |
| Resource Clearing Price ($/MW-day) | $28.92 | $28.92 | $28.92 | $28.92 | $28.92 | |

*Offered and Cleared MW quantities include resources that received CIL Exception and those associated w ith pre-OATT grandfathered transmission.
Attachment G of Manual 14B provides a mapping of outside Balancing Authorities to the External Source Zones.

The Table below provides a breakdown of the offered and cleared MWs by season by Resource Type. There were 1,081 MW of Summer capability and 605.6 MW of Winter capability offered in the auction. All 605.6 MW of Winter were matched with Summer resources to meet the annual Capacity Performance capability requirement.

**Table 12 – Offered and Cleared (UCAP) by Resource Type by Season**

| | Offered MW (UCAP) | | | Cleared MW (UCAP) | | |
|---|---|---|---|---|---|---|
| Resource Type | Annual Capacity Performance | Summer Capacity Performance | Winter Capacity Performance | Annual Capacity Performance | Summer Capacity Performance | Winter Capacity Performance |
| GEN | 138,153.2 | 40.5 | 605.6 | 131,779.3 | 38.2 | 605.6 |
| DR | 9,942.8 | 203.6 | - | 7,804.3 | 188.4 | - |
| EE | 7,580.1 | 836.9 | - | 7,289.7 | 379.0 | - |
| **Grand Total** | **155,676.1** | **1,081.0** | **605.6** | **146,873.3** | **605.6** | **605.6** |

Figure 2 provide the trend in offered and cleared DR and EE by Delivery Year. While DR offered and cleared has been moderately down over the last 3 Delivery Years, EE continues to increase and was significantly up in the 2024/2025 BRA. The amount of PRD remains small and is slightly up in the 2024/2025 Delivery Year.

**Figure 2 - DR and EE offered and cleared MW by Delivery Year by Type**

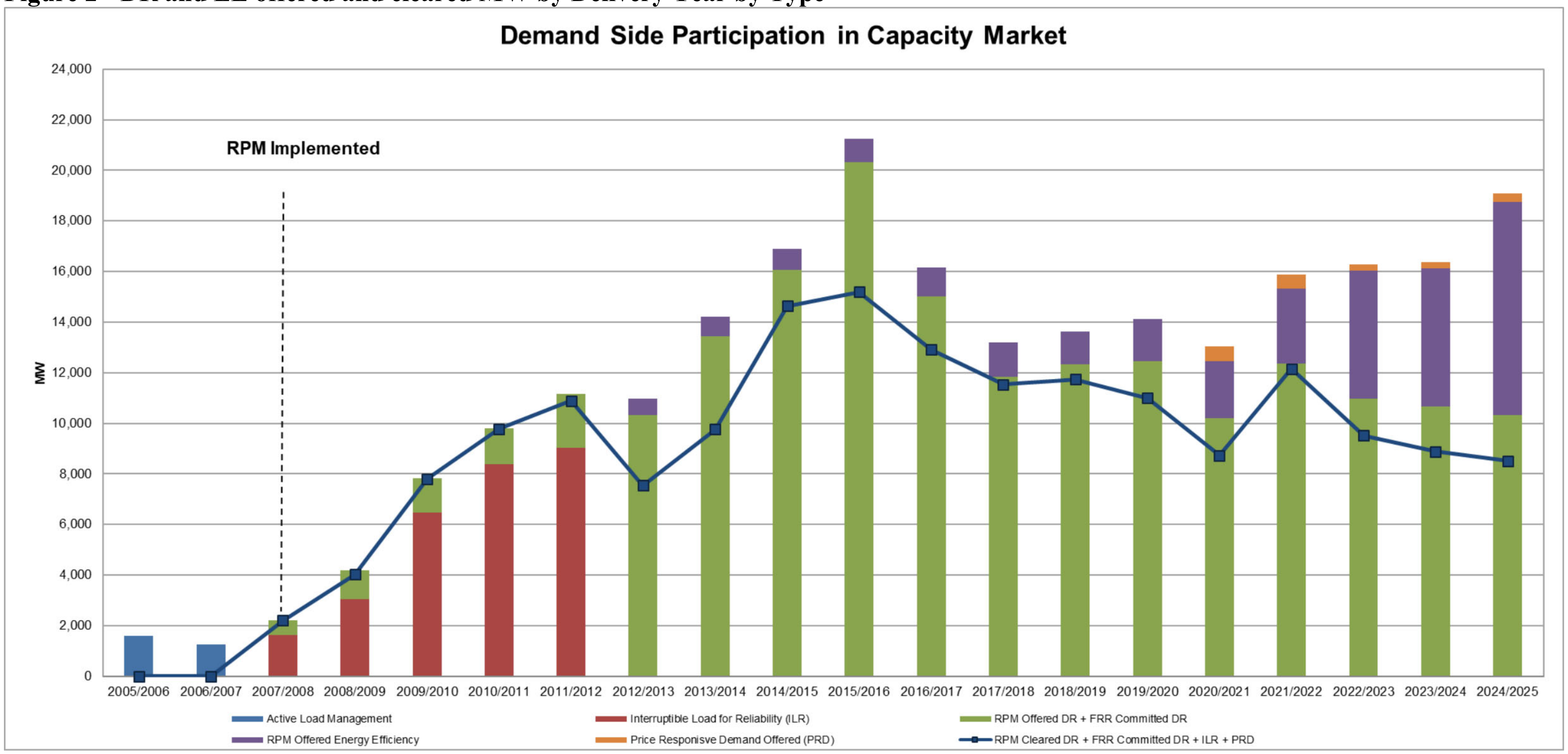


Table 13 provides a breakdown of offered and cleared DR and EE by LDA. COMED cleared the most DR and EE (2,605.4 MW), followed by AEP (1,893.6 MW) and then DOM (1,611.6 MW). In most cases, the amount of DR and EE is correlated to the size of the load in the Zone.

**Table 13 - DR and EE offered and cleared by LDA**

| | | Offered MW (UCAP)* | | | Cleared MW (UCAP)* | | |
|---|---|---|---|---|---|---|---|
| **LDA** | **Zone** | **DR** | **EE** | **Total** | **DR** | **EE** | **Total** |
| EMAAC | AECO | 93.8 | 153.8 | **247.6** | 66.8 | 152.0 | **218.8** |
| EMAAC/DPL-S | DPL | 173.1 | 208.2 | **381.3** | 147.7 | 202.4 | **350.1** |
| EMAAC | JCPL | 175.1 | 326.8 | **501.9** | 131.8 | 317.4 | **449.2** |
| EMAAC | PECO | 429.3 | 615.8 | **1,045.1** | 366.3 | 583.9 | **950.2** |
| PSEG/PS-N | PSEG | 389.0 | 817.2 | **1,206.2** | 285.7 | 771.4 | **1,057.1** |
| EMAAC | RECO | 3.4 | 3.2 | **6.6** | 2.7 | 3.2 | **5.9** |
| **EMAAC Sub Total** | | **1,263.7** | **2,125.0** | **3,388.7** | **1,001.0** | **2,030.3** | **3,031.3** |
| PEPCO | PEPCO | 232.0 | 421.1 | **653.1** | 164.5 | 398.9 | **563.4** |
| BGE | BGE | 224.1 | 392.9 | **617.0** | 198.1 | 380.3 | **578.4** |
| MAAC | METED | 258.4 | 166.3 | **424.7** | 218.8 | 157.1 | **375.9** |
| MAAC | PENELEC | 347.6 | 148.0 | **495.6** | 314.0 | 140.6 | **454.6** |
| PPL | PPL | 658.4 | 422.0 | **1,080.4** | 608.7 | 392.9 | **1,001.6** |
| **MAAC** Sub Total** | | **2,984.2** | **3,675.3** | **6,659.5** | **2,505.1** | **3,500.1** | **6,005.2** |
| RTO | AEP | 1,590.1 | 883.4 | **2,473.5** | 1,102.8 | 790.8 | **1,893.6** |
| RTO | APS | 861.8 | 407.9 | **1,269.7** | 635.1 | 375.8 | **1,010.9** |
| ATSI/ATSI-C | ATSI | 953.5 | 689.1 | **1,642.6** | 674.6 | 587.3 | **1,261.9** |
| COMED | COMED | 1,899.8 | 1,284.7 | **3,184.5** | 1,542.0 | 1,063.4 | **2,605.4** |
| DAY | DAY | 233.5 | 146.1 | **379.6** | 191.1 | 128.3 | **319.4** |
| DEOK | DEOK | 231.2 | 202.2 | **433.4** | 221.9 | 188.1 | **410.0** |
| RTO | DOM | 892.4 | 977.2 | **1,869.6** | 710.5 | 901.1 | **1,611.6** |
| RTO | DUQ | 210.9 | 151.1 | **362.0** | 120.6 | 133.8 | **254.4** |
| RTO | EKPC | 289.0 | - | **289.0** | 289.0 | - | **289.0** |
| **Grand Total** | | **10,146.4** | **8,417.0** | **18,563.4** | **7,992.7** | **7,668.7** | **15,661.4** |

* MW values include both Annual and Summer-Period Capacity Performance DR and EE

** MAAC sub-total includes all MAAC Zones

**Price Responsive Demand Participation**

332 MW (UCAP) of PRD was elected and committed in the 2024/2025 BRA. PRD is provided by a PJM Member that represents retail customers having the ability to predictably reduce consumption in response to changing wholesale prices. In the PJM Capacity Market, a PRD Provider may voluntarily make a firm commitment of the quantity of PRD that will reduce its consumption in response to real time energy price during a Delivery Year. A PRD Provider that is committing PRD in a BRA must also submit a PRD election in the Capacity Exchange system which indicates the Nominal PRD Value in MWs that the PRD Provider is willing to commit at different reservation prices ($/MW-day). The VRR curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW quantity of elected PRD where the leftward shift occurs only for the portion of the VRR Curve at or above the PRD Reservation price. The Planning Parameters includes a breakdown of elected PRD in ICAP which can be converted to UCAP by taking ICAP * FPR. The breakdown of PRD UCAP that elected and committed is: 174 MW in the BGE, 120 MW in the PEPCO LDA, 24 MW in the rest of EMAAC LDA and 14 MW were located in the DPL-South LDA. The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW value of these quantities at the PRD Reservation Price. Once committed in a BRA, a PRD commitment cannot be replaced; the commitment can only be satisfied through the registration of price response load in the DR Hub system prior to or during the Delivery Year.

Independent Statistics & Analysis
U.S. Energy Information Administration

# Generating Unit Annual Capital and Life Extension Costs Analysis

December 2019

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the Department of Energy or other Federal agencies.

# Generating Unit Annual Capital and Life Extension Costs Analysis

In a period of accelerating retirements of electric power generators, EIA sought to revisit its assumptions of age-related generation costs. EIA commissioned Sargent & Lundy (S&L) to evaluate capital expenditures (CAPEX) and operations and maintenance (O&M) costs for non-nuclear generating units, with a particular emphasis on how costs of coal and other fossil-fueled plants change over time. The following report represents S&L's findings. A separate EIA report, *Updates to Cost Assumptions in the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS)*,[1] details subsequent updates to the EMM module.

The following report was accepted by EIA in fulfillment of contract number DE-EI0003250. All views expressed in this report are solely those of the contractor and acceptance of the report in fulfillment of contractual obligations does not imply agreement with nor endorsement of the findings contained herein. Responsibility for accuracy of the information contained in this report lies with the contractor. Although intended to be used to inform the updating of EIA's EMM module of NEMS, EIA is not obligated to modify any of its models or data in accordance with the findings of this report.

[1] https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/addendum.pdf

Prepared by

Sargent & Lundy Consulting

# FINAL

## Generating Unit Annual Capital and Life Extension Costs Analysis

Final Report on Modeling Aging-Related Capital and O&M Costs

Prepared for

eia

U.S. Energy Information Administration

55 East Monroe Street
Chicago, Illinois 60603-5780

SL-014201
May 2018

**LEGAL NOTICE**

**Sargent & Lundy** is a full-service architect-engineering firm that has been dedicated exclusively to the electric power industry for over 125 years. Sargent & Lundy has provided comprehensive planning, development, permitting, technical and financial consulting, engineering, design, construction management, and commissioning services for electric power generation and power delivery projects—1,557 clients in 88 countries worldwide—since its founding in 1891. Having designed 958 power plants, totaling 140,667 MW of electric generation capacity, Sargent & Lundy is regarded as one of the oldest, largest, and most experienced power generation engineering companies in the U.S.

Sargent & Lundy's roles on electric power generation projects include full-design architect-engineer, owner's engineer, lender's independent engineer/technical advisor, and consultant. Our services include specialized technical advisory and consulting services to complete engineering and program management, encompassing procurement, construction management, technology transfer, and assistance with construction. Sargent & Lundy provides professional consulting, engineering, and design services throughout the lifecycle of power generation projects, from project concept and development, through detailed design and procurement, to construction and operation.

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# ACRONYMS AND ABBREVIATIONS

| Term | Definition or Clarification |
|---|---|
| 2017$ | 2017 dollars |
| A&G | Administrative and general |
| AEO | *Annual Energy Outlook* |
| ARIMA | Autoregressive integrated moving average |
| ATB | Annual Technology Baseline |
| CAPEX | Capital expenditures |
| CC | Combined cycle |
| CF | Capacity factor |
| COD | Commercial operation date |
| CT | Combustion turbine |
| DOE | Department of Energy |
| EIA | Energy Information Administration |
| EMM | Electricity Market Module |
| ESP | Electrostatic precipitator |
| FERC | Federal Energy Regulatory Commission |
| FERC Form 1 | FERC Form No. 1 |
| FGD | Flue gas desulfurization |
| Hg | Mercury |
| HP | High pressure |
| ID | Identifier or induced draft |
| IP | Intermediate pressure |
| IPP | Independent power producer |
| IRENA | International Renewable Energy Agency |

# ACRONYMS AND ABBREVIATIONS

| Term | Definition or Clarification |
|---|---|
| kW | Kilowatts |
| kW-yr | Kilowatt-years |
| LCOE | Levelized cost of electricity |
| LP | Low pressure |
| MMRA | Major maintenance reserve account |
| MW | Megawatts |
| MWh | Megawatt-hours |
| $NO_X$ | Nitrogen oxide |
| NREL | National Renewable Energy Laboratory |
| OEA | Office of Energy Analysis |
| O&M | Operations and maintenance |
| PM | Particulate matter |
| PV | Photovoltaic |
| $R^2$ | R-squared |
| Sargent & Lundy | Sargent & Lundy LLC |
| $SO_2$ | Sulfur dioxide |
| TCP | Total Cost of Plant |

# EXECUTIVE SUMMARY

## IDENTIFYING IMPACTS OF AGING ON GENERATION COST AND OPERATION

Sargent & Lundy LLC (Sargent & Lundy) was engaged by the Office of Energy Analysis (OEA) of the U.S. Energy Information Administration (EIA), an agency within the U.S. Department of Energy (DOE), to conduct a study to improve the ability of the Electricity Market Module (EMM) to represent the changing landscape of electricity generation and to more accurately represent costs, which will improve projections for generating capacity, generator dispatch, and electricity prices. The EMM is a submodule within the EIA's National Energy Modeling System (NEMS), a computer-based energy supply modeling system that is used for the EIA's *Annual Energy Outlook* (AEO) and other analyses.

In particular, the purpose of this study was to provide information that may enable the EIA to more accurately represent costs associated with operation of the existing fleet of U.S. generators as they age. This includes capital expenditures (CAPEX) related to ongoing operations as well as potential increases in operations and maintenance (O&M) costs attributable to declining performance due to aging.

The primary focus of our analysis was existing fossil fuel generators. The study also included existing wind, solar, hydro, and other renewable generators. The work scope did not include analysis of nuclear units.

The generating capacity types represented in the EMM that were included in our analysis comprised:

- Coal steam plants
- Gas/oil steam plants
- Gas/oil combined-cycle (CC) plants
- Gas/oil combustion turbines (CTs)
- Conventional hydropower
- Pumped storage – hydraulic turbine reversible
- Solar thermal – central tower
- Solar photovoltaic (PV) – single-axis tracking
- Geothermal
- Wind

For most types of generators evaluated, we did not find a statistically significant relationship between plant age and costs (both CAPEX and O&M). CAPEX spending over the life of each plant represents a series of capital projects—rather than a single life extension project—that includes both discretionary spending and vendor-specified spending. For discretionary spending, different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances. Vendor-specified spending is primarily for major maintenance, typically based on cumulative hours of operation and/or cumulative starts, and more commonly applied to gas/oil CC and CT plants. We did, however, find a statistically significant relationship between age and CAPEX spending for fossil steam coal generators with flue gas desulfurization (FGD) equipment, and between age and O&M spending for conventional hydroelectric plants and wind turbines. We also found age and CAPEX spending to be significantly correlated for CC and CT plants, although measured in terms of operating hours or starts, rather than years. Table ES-1 summarizes the variables found to have a significant effect on annual changes in real spending per kilowatt (kW) for each generator type. We recommend the EIA incorporate these variables in the EMM representation of CAPEX and O&M.

**Table ES-1 — Variables Affecting Annual Changes in Real Spending per kW**

| Generating Capacity | CAPEX Spending | O&M Spending |
|---|---|---|
| Coal Steam Plants | Age and FGD (see Table ES-3) | - |
| Gas/Oil Steam Plants | Capacity (see Table ES-5) | - |
| Gas/Oil Combined-Cycle Plants | Operating Hours (see Table ES-7) | - |
| Gas/Oil Combustion Turbines | Starts (see Table ES-7) | - |
| Conventional Hydropower | - | Age (Regression Equation) |
| Pumped Storage – Hydraulic Turbine Reversible | - | - |
| Solar Thermal – Central Tower | - | - |
| Solar Photovoltaic – Single-Axis Tracking | - | - |
| Geothermal | - | - |
| Wind | Capacity (see Table ES-11) | Age (Regression Equation) |

While we did not find a consistent relationship between aging and CAPEX and O&M costs, changes in performance-related factors and external market conditions are also related to changes in these costs over time. Examples of these factors and conditions include the following:

- Plant efficiency (heat rate)
- Capacity degradation
- Outage rates
- Market prices (electricity, fuel)

These factors and conditions were not part of the scope of our study. We recommend the EIA consider studying these in the future.

## MODELING IMPACTS OF AGING IN EIA PROJECTIONS

### Existing Treatment of Aging in EIA's Electricity Market Module

The EMM currently accounts for power plant aging through a one-time step increase in annual CAPEX that is intended to extend the life or preserve the performance of an existing generator. In the EMM, costs for plant O&M do not vary with plant age.

As modeled in the EMM, a generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, O&M costs, and annual CAPEX. The average annual CAPEX in the EMM is $0.18 per kilowatt-year (/kW-year) for existing CC plants, $9/kW-year for existing gas/oil steam plants, and $18/kW-year for existing coal plants (in constant 2017 dollars). These amounts are increased to $7.25/kW-year, $16/kW-year, and $25/kW-year, respectively, after a plant reaches 30 years of age.[1] The average annual CAPEX in the EMM for existing CT plants is $1.52/kW-year with no life extension costs. The other generating technologies in the EMM are not currently modeled with either CAPEX or life extension costs.

### Need for Update to EIA's Treatment of Aging

The existing CAPEX values in the EMM were derived from yearly changes in plant in service accounts reported on the Federal Energy Regulatory Commission (FERC) Form No. 1 ("FERC Form 1").[2] The O&M costs in the EMM are also derived from FERC Form 1. However, FERC Form 1 does not cover merchant power plants or independent power producers (IPPs), leaving a large gap in the data. For example, out of approximately 35,000 generating units in the U.S., roughly 21,000 (60%) are IPPs. The EIA currently extrapolates data from FERC Form 1 to represent all plants covered in the EMM.

Sargent & Lundy's update to the EMM treatment of aging examined the potential adaptation of the EMM to represent changes in age-related spending patterns by various methods. This examination required the following steps:

[1] Internal communication with EIA, February 2018.
[2] FERC Form 1 is an annual regulatory requirement for major electric utilities, licensees, and others designed to collect non-confidential financial and operational information.

1. Gathering of in-house data from independent power projects and other plants, in addition to FERC Form 1 data.
2. Incorporation of O&M and capital spending forecasts by plant owners and operators with firsthand knowledge of plant operating history and future needs, thereby extending the range of plant operating years over which to characterize spending, compared with FERC Form 1 data that is limited to historical data.
3. Removal of capital spending for major modifications relating to environmental compliance, which would be modeled on a case-specific basis.
4. Identification of the most significant variables affecting age-related spending from commonly reported plant data—such as plant capacity (kW), annual generation (megawatt-hours [MWh]), age, fuel type, emission controls, and regulatory environment—using regression analysis.
5. Representation of age-related costs as either fixed ($/kW-year) or variable ($/MWh) according to generating technology and typical maintenance practices.
6. Application of capital spending and/or age-related costs to the EMM representations of long-term fixed O&M, variable O&M, and ongoing capital spending for each generating technology.

The assessment methodology used by Sargent & Lundy for the EMM update included an in-depth process of data validation, data normalization, and statistical testing, which is described in detail in Section 2.

## ANALYSIS OF AGING IMPACTS IN PUBLICLY-REPORTED COST INFORMATION

### Cost Breakdowns in Reported Data

Our analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in $/kW-year, while variable O&M is typically expressed in $/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

The reporting formats of our in-house data and the FERC Form 1 data have a clear delineation between CAPEX and O&M. However, while the in-house data often contains an explicit breakdown between fixed and variable O&M, the FERC Form 1 accounts for O&M are not categorized as such. Rather, the reported O&M costs in a given account are the combined fixed and variable costs at the reported generating output. Thus, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data.

O&M costs for the following technologies are essentially all fixed: solar thermal (central tower), solar PV (single-axis tracking), geothermal, and wind. By definition, fixed O&M costs are independent of plant generation, so they are expressed in $/kW-year.

O&M costs for the following technologies include a significant variable component: coal steam, gas/oil steam, gas/oil CC, gas/oil CTs, conventional hydropower, and pumped storage (hydraulic turbine reversible). By definition, variable O&M costs are proportional to plant generation and are typically expressed in $/MWh.

As mentioned, the variable O&M components cannot be clearly delineated from the total reported O&M costs. For this assessment, the variable components were combined with the fixed components and expressed in $/kW-year. The combined total O&M was found to correspond to the combined total O&M representation in the EMM, which includes a $/MWh variable O&M breakout, as presented in the subsections below.

CAPEX spending values, expressed in $/kW-year, were derived from the new dataset as an additive to the EMM O&M costs and as replacements for the existing EMM CAPEX representation for all technologies, except for gas/oil CC and gas/oil CTs. CAPEX spending for gas/oil CC and gas/oil CTs was found to be primarily for major maintenance events, which are already represented as a $/MWh variable O&M cost in the EMM.

### Data Compilation

The data compilation for this analysis consisted of the following annual plant data (any available data from 1980 to 2060, historical or forecasted by plant owner):

- Plant megawatts (MW) (summer)
- Annual MWh
- Annual O&M (from FERC Form 1)
- Annual O&M (from other sources)
- Annual CAPEX (from FERC Form 1)
- Annual CAPEX (from other sources)
- Annual environmental compliance costs

All available and validated cost data over the plant operating life, historical or forecasted, was normalized as follows for each plant:

- Annual O&M in 2017 $/kW-year versus age (years from commercial operation date [COD])
- Annual CAPEX in 2017 $/kW-year versus age (years from COD)
- Annual O&M + CAPEX in 2017 $/kW-year versus age (years from COD)

In all cases, the yearly values are expressed in constant 2017 price levels and would increase annually with the inflation rate.

## IDENTIFYING CHANGES IN SPENDING PATTERNS OVER PLANT LIFE

### Differences in Spending Approach by Plant Type

CAPEX spending over the life of each plant represents a series of capital projects throughout the plant life, rather than a single life extension project. This consists of both discretionary spending and vendor-specified spending, examples of which are as follows:

- Discretionary spending is notable for most coal steam and gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances. Typical industry-standard frequencies for repairs and replacements of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.
- Vendor-specified major maintenance spending, such as commonly applied to gas/oil CC and gas/oil CTs, is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC and CT plants is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:
  - Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
  - Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

### Potential Benefits of CAPEX and O&M Spending on Future Spending

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

### Potential Impacts of Plant Age on Future Spending

The spending characteristics described in the previous subsections are evident in the datasets, which reveal significant variability in plant spending as a function of age. Sargent & Lundy's evaluation therefore examined additional variables that might explain some of the variability in age-related spending: plant capacity (MW), capacity factor, external market conditions, regulatory environment, fuel characteristics, and FGD. These additional variables and their effects are described in the following subsections.

### Effect of Plant Capacity (MW)

The effect of plant MW capacity on age-related spending, expressed in $/kW-year, was examined by breaking the dataset into separate plant size categories, summarized as follows:

- Coal Steam
  - All MW
  - < 500 MW
  - 500 MW – 1,000 MW
  - 1,000 MW – 2,000 MW
  - > 2,000 MW
- Gas/Oil Steam
  - < 500 MW
  - 500 MW – 1,000 MW
  - > 1,000 MW
- Gas/Oil CC
  - All MW
  - < 500 MW
  - 500 MW – 1,000 MW
  - > 1,000 MW
- Gas/Oil CT
  - All MW
  - < 100 MW
  - 100 MW – 300 MW
- Conventional Hydroelectric
  - All MW
  - < 100 MW
  - 100 MW – 500 MW
  - > 500 MW
- Pumped Hydroelectric Storage
  - All MW
  - < 100 MW
  - 100 MW – 500 MW
  - > 500 MW
- Solar Photovoltaic
  - < 5 MW
  - > 5 MW
- Wind Turbine
  - All MW
  - < 100 MW
  - 100 MW – 200 MW
  - > 200 MW

For some of the MW breakdowns above, the age coefficient in the regression analysis of CAPEX or O&M was found to be statistically significant. For the other MW breakdowns, an average value by age group was found to be more appropriate (see Table ES-1).

### Effect of Plant Capacity Factor

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure ES-1. A similar decline also occurred with the gas/oil steam plants, as shown in Figure ES-2.

**Figure ES-1 — Capacity Factor vs. Age for All Coal Plants**

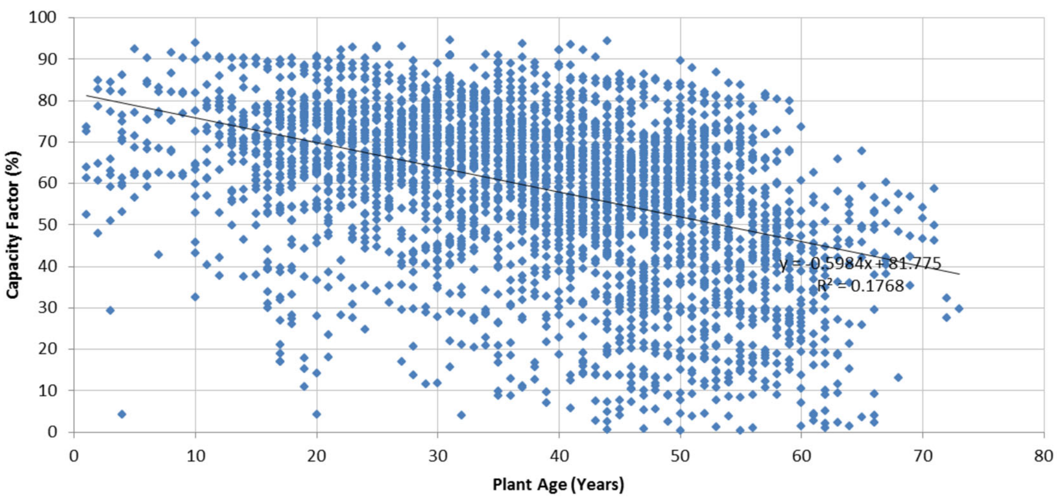
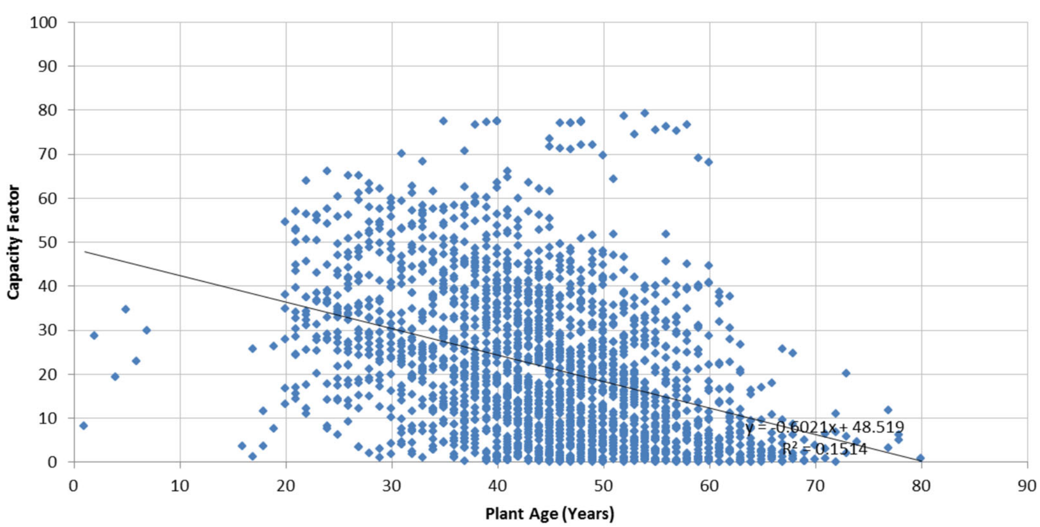



**Figure ES-2 — Capacity Factor vs. Age for All Gas/Oil Steam Plants**



## Effect of External Market Conditions

The declining capacity factors with age, shown above, may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for coal steam and gas/oil steam plants include:

- Competition with lower gas prices and more efficient gas turbines
- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some coal steam and gas/oil steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.[3]

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient coal steam and gas/oil steam plants would likely retire under the following circumstances:

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

Some of the older coal steam plants (23 in this data sample) maintained consistently high capacity factors throughout their plant lives, with no real increase in spending. These high capacity factor plants had an installed capacity ranging from 70 MW to 2,400 MW, with an average of 850 MW and an average COD of 1961. These plants are slightly larger and older, on average, than the entire dataset of coal steam plants, which have an average installed capacity of 720 MW and an average COD of 1964. Table ES-2 shows the average capacity factors and O&M and CAPEX spending for the entire dataset of coal steam plants compared with the older consistently high capacity factor plants.

[3] Kumar, N., Besuner, P., Lefton, S., and Agan, D., *Power Plant Cycling Costs*, National Renewable Energy Laboratory, April 2012.

**Table ES-2 — High Capacity Factor Coal Plants – Spending Comparison**

| | Average – All Years | Years 1-20 | Years 20-40 | Years 40-80 |
|---|---|---|---|---|
| Capacity Factor – All Plants | 59.1% | 66.8% | 64.5% | 52.9% |
| Capacity Factor – High CF Plants | 74.0% | - | 72.8% | 74.4% |
| O&M – All Plants (2017 $/kW-yr) | 46.01 | 53.90 | 40.06 | 48.77 |
| CAPEX – All Plants (2017 $/kW-yr) | 22.78 | 17.92 | 26.20 | 21.25 |
| Total – All Plants (2017 $/kW-yr) | 68.67 | 71.86 | 66.25 | 69.82 |
| O&M – High CF Plants (2017 $/kW-yr) | 36.65 | - | 31.07 | 38.78 |
| CAPEX – High CF Plants (2017 $/kW-yr) | 20.26 | - | 23.13 | 19.16 |
| Total – High CF Plants (2017 $/kW-yr) | 57.02 | - | 54.20 | 58.10 |

Market conditions at the older, high capacity factor plants may have led to fewer competing resources, which would support higher levels of dispatch and higher capacity factors. In addition, lower cycling requirements at those plants would have reduced spending requirements.

### Effect of Regulatory Environment

Owners of coal steam plants in deregulated states were found to have no aversion to capital spending compared to plant owners in regulated states. Some of the difference may be due to higher labor costs in many of the deregulated states. This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending was not apparent at this level of detail.

### Effect of Fuel Characteristics

Sargent & Lundy's regression analysis compared CAPEX spending for coal steam plants with bituminous and subbituminous coal types. The results indicate that average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

### Effect of Flue Gas Desulfurization

The regression analysis indicated a significant difference in CAPEX spending for coal plants with FGD. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently than at plants without FGD.

## PROPOSED UPDATES TO EMM METHODOLOGY

The EMM captures changes in age-related spending patterns through multiple cost categories: CAPEX, O&M, fuel, energy sales, and capacity sales. The updates below relate only to the CAPEX and O&M. The focus of the work scope was to more accurately represent power plant aging impacts on CAPEX and O&M. Detailed derivations of fixed and variable O&M costs for the EMM were not part of the work scope.

Sargent & Lundy's recommended updates to the fixed and variable O&M costs and CAPEX in the EMM for each generating technology are summarized in the tables below. Values are in constant 2017 price levels and are incurred in every year of plant operation, starting from commercial operation through plant retirement. In all cases, the yearly values would increase annually with the inflation rate.

### Coal Steam

Sargent & Lundy's analysis of the coal steam dataset (Appendix A) identified two significant variables affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): age and FGD. Variables not having a significant effect on annual changes in real CAPEX spending (on a constant $/kW-year basis) were: plant capacity (kW), fuel type, and regulatory environment. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table ES-3 compares the new CAPEX values derived from the coal steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

**Table ES-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors**

| Net Total CAPEX (2017 $/kW-year) | $/kW-yr (Years 1-10) | $/kW-yr (Years 10-20) | $/kW-yr (Years 20-30) | $/kW-yr (Years 30-40) | $/kW-yr (Years 40-50) | $/kW-yr (Years 50-60) | $/kW-yr (Years 60-70) | $/kW-yr (Years 70-80) |
|---|---|---|---|---|---|---|---|---|
| New Value – No FGD* | 17.16 | 18.42 | 19.68 | 20.94 | 22.20 | 23.46 | 24.72 | 25.98 |
| New Value – with FGD* | 22.84 | 24.10 | 25.36 | 26.62 | 27.88 | 29.14 | 30.40 | 31.66 |
| Existing EMM Value | 17.55 | 17.55 | 17.55 | 24.62 | 24.62 | 24.62 | 24.62 | 24.62 |

*Calculated to the midpoint of the given age band.

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most coal steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

The new values also account for CAPEX relating to FGD. An FGD system tends to be capital-intensive to own and operate. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently than at plants without FGD.

O&M costs for the coal steam plants include a significant variable component. By definition, variable O&M costs are proportional to plant generation and are typically expressed in \$/MWh. As previously mentioned, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data. For this assessment, the variable component was combined with the fixed component and expressed in \$/kW-year. The combined total O&M in the coal steam plant dataset for this analysis was found to be nearly equivalent to the existing combined total O&M representation in the EMM, which already includes the necessary \$/MWh variable O&M breakout (see Table ES-4).

**Table ES-4 — Coal Steam O&M Comparison with Existing EMM**

| | Fixed O&M (2017 \$/kW-yr) | Variable O&M (2017 \$/MWh)* | Variable O&M (2017 \$/kW-yr)** | Total O&M (2017 \$/kW-yr)** |
|---|---|---|---|---|
| Coal Steam Dataset Results – All Plants | 36.81 | 1.78 | 9.20 | 46.01 |
| < 500 MW | 44.21 | 1.78 | 9.20 | 53.41 |
| 500 MW – 1,000 MW | 34.02 | 1.78 | 9.20 | 43.22 |
| 1,000 MW – 2,000 MW | 28.52 | 1.78 | 9.20 | 37.72 |
| > 2,000 MW | 33.27 | 1.78 | 9.20 | 42.47 |
| Existing EMM Value*** | 40.63 | 1.78 | 9.20 | 49.83 |

*Fixed and variable split is estimated using the existing EMM variable O&M cost of \$1.78/MWh.
**Calculated at the coal steam dataset average capacity factor of 59%.
***Source: Internal communication with EIA, February 2018.

### Gas/Oil Steam

The analysis of the gas/oil steam dataset (Appendix B) identified only one significant variable affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): plant capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table ES-5 compares the new CAPEX values derived from the gas/oil steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

**Table ES-5 — Gas/Oil Steam CAPEX Results**

| Plant Size | Net Total CAPEX (2017 $/kW-year) | |
|---|---|---|
| | Years 1-30 | Years 30-80 |
| Gas/Oil Steam Dataset Results – All Plants | 15.96 | 15.96 |
| New Value: < 500 MW | 18.86 | 18.86 |
| New Value: 500 MW – 1,000 MW | 11.57 | 11.57 |
| New Value: > 1,000 MW | 10.82 | 10.82 |
| Existing EMM Value | 9.14 | 16.21 |

“Life extension costs” in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a gas/oil steam plant are not absolute, but rather indicative of when a gas/oil steam plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

Typical industry-standard frequencies for repairs and replacement of major equipment are similar to those of coal units, as presented in the previous section.

The use of a constant annual value on the modeling of annual CAPEX would be similar to representing a major maintenance reserve account (MMRA), which is commonly used for non-recourse financing of power projects. MMRAs are usually required by power project lenders over the tenor of debt as protection against maintenance spending uncertainty. An MMRA is typically funded by annual contributions drawn from a project's cash flow, sometimes as a uniform annual amount. Annual contribution levels are based on estimated long-term maintenance expenditure patterns. Over the long term, annual contributions represent a smoothed version of irregular actual annual values.

The use of a long-term average value also recognizes the inherent variability in long-term spending patterns for any given plant. Since the EMM is a large-scale model, it is conceptually designed to represent plant types as averages rather than as individual plants. When summed across a large number of plants in a utility system, some of the variability in annual expenditure patterns would tend to even out. The level of accuracy between average values and year-specific values for a given plant type is nearly equivalent in large-scale models.

O&M costs for the gas/oil steam plants include a significant variable component, although typically smaller than coal units. The combined total O&M in the gas/oil steam plant dataset for this analysis was found to be somewhat lower than the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (see Table ES-6). However, the variable O&M of $8.23/MWh in the EMM is much higher than values Sargent & Lundy has observed in actual gas/oil steam plants and should not be higher than the variable O&M of $1.78/MWh in the EMM used for the coal units.

**Table ES-6 — Gas/Oil Steam O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh)* | Variable O&M (2017 $/kW-yr)** | Total O&M (2017 $/kW-yr)** |
|---|---|---|---|---|
| Gas/Oil Steam Dataset Results – All Plants | 24.68 | 1.00 | 1.84 | 26.52 |
| < 500 MW | 29.73 | 1.00 | 1.84 | 31.57 |
| 500 MW – 1,000 MW | 17.98 | 1.00 | 1.84 | 19.82 |
| > 1,000 MW | 14.51 | 1.00 | 1.84 | 16.35 |
| Existing EMM Value*** | 19.68 | 8.23 | 15.14 | 34.82 |

*Fixed and variable split is estimated using an approximate value for variable O&M of $1.00/MWh based on confidential projects.
**Calculated at the gas/oil steam dataset average capacity factor of 21%.
***Source: Internal communication with EIA, February 2018.

### Gas/Oil Combined Cycle and Gas/Oil Combustion Turbine

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CC and gas/oil CT plants represents a series of capital projects throughout the plant life, which include projects for "life extension." Most CAPEX spending for gas/oil CC and gas/oil CT plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC and CT plants is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs described in the previous subsection, major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant $/MWh with annual escalation.

Table ES-7 compares the new CAPEX and O&M values derived from the gas/oil CC and CT datasets with the values currently used in the EMM. As indicated above, the combined CAPEX and O&M values in the datasets would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, some of the EMM values are higher than values Sargent & Lundy has observed in actual CC and CT plants, as detailed below:

- The EMM fixed and variable O&M costs for CC plants are reasonable for smaller CC installations (< 500 MW) but high for larger plants.
- The EMM CAPEX addition of $7/kW-year after 30 years of operation should not be represented as a fixed cost. As previously mentioned, age-related costs would be built into the $/MWh variable O&M and would be a function of cumulative operating hours rather than operating years.

- The EMM fixed and variable O&M costs for CT plants are high for all plant sizes. Since most CT plants operate as peaking plants with low capacity factors, the variable O&M component is likely to be based on equivalent starts rather than equivalent operating hours.

**Table ES-7 — Gas/Oil CC and CT CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh)* | Variable O&M (2017 $/kW-yr)* | Total O&M (2017 $/kW-yr)* | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr)** |
|---|---|---|---|---|---|---|
| CC Dataset Results (All Plants) | 13.08 | 3.91 | (included in CAPEX) | 13.08 | 15.76 | 28.84 |
| < 500 MW | 15.62 | 4.31 | (included in CAPEX) | 15.62 | 17.38 | 33.00 |
| 500 MW – 1,000 MW | 9.27 | 3.42 | (included in CAPEX) | 9.27 | 13.78 | 23.05 |
| > 1,000 MW | 11.68 | 3.37 | (included in CAPEX) | 11.68 | 13.57 | 25.25 |
| Existing EMM Value** | 27.52 | 2.64 | 10.64 | 38.16 | 0.18; 7.25 (after year 30) | 38.34; 45.41 (after year 30) |
| | | | | | | |
| CT Dataset Results (All Plants) | 5.33 | (starts based) | (included in CAPEX) | 5.33 | 6.90 | 12.23 |
| < 100 MW | 5.96 | (starts based) | (included in CAPEX) | 5.96 | 9.00 | 14.96 |
| 100 MW – 300 MW | 6.43 | (starts based) | (included in CAPEX) | 6.43 | 6.18 | 12.61 |
| > 300 MW | 3.99 | (starts based) | (included in CAPEX) | 3.99 | 6.95 | 10.94 |
| Existing EMM Value*** | 12.60 | 14.63 | 5.13 | 17.73 | 1.52 | 19.25 |

*Fixed and variable split is estimated, assuming all CAPEX costs are represented as variable O&M, either hours-based ($/MWh) or starts-based ($/start).
**Calculated at the dataset average capacity factor of 46% for CC and 4% for CT.
***Source: Internal communication with EIA, February 2018.

### Conventional Hydroelectric

Overall, the conventional hydroelectric dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. The average CAPEX value over all operating years is $22.56/kW-year. The dataset does support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 $/kW-year = 22.360 + (0.073 × age)**

The CAPEX and O&M values derived from the conventional hydroelectric dataset are significantly higher than the existing values used in the EMM (Table ES-8) and outside the range of values published in the AEO[4] and by the International Renewable Energy Agency (IRENA).[5] The reasons for this discrepancy are not known without having the data sample used for the EMM values. It appears that the EMM does not currently account for CAPEX or life extension expenditures for conventional hydroelectric.

**Table ES-8 — Hydroelectric CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr) |
|---|---|---|---|---|
| Conventional Hydroelectric Dataset Results – All Plants | 22.00 | - | 22.56 | 44.56 |
| Existing EMM Value* | 14.58 | 0.00 | 0.00 | 14.58 |

*Source: Internal communication with EIA, February 2018.

## Pumped Storage

Overall, the pumped storage dataset does not support any age-related CAPEX or O&M spending trend across the full data and on any of the subsets by plant size. The average value over all operating years is $14.83/kW-year for CAPEX and $23.63/kW-year for O&M (Table ES-9). The existing values used in the EMM are not available.

**Table ES-9 — Pumped Storage CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr) |
|---|---|---|---|---|
| Pumped Storage Dataset Results – All Plants | 23.63 | - | 14.83 | 38.46 |
| Existing EMM Value | N/A | N/A | N/A | N/A |

## Solar Photovoltaic

The solar PV dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Sargent & Lundy notes that the average change in the "Total Cost of Plant" (TCP) reported in the FERC data for the limited usable dataset (15 sites not filtered out) is approximately $26/kW-year. However, due to the limited dataset, lack of clarity on what qualifies as a change to the TCP, and general lack of

4 Energy Information Administration, *Annual Energy Outlook 2018*, Cost and Performance Characteristics (Table 8.2), February 2018.
5 International Renewable Energy Agency, *Renewable Energy Technologies: Cost Analysis Series, Hydropower*, June 2012.

consistency in the FERC capital cost data provided, Sargent & Lundy advises that caution be taken when trying to establish any definitive solar PV capital cost trends from the FERC data.

The solar PV dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, based upon closer inspection of the data, a more appropriate predictor of O&M spending for this dataset would be a simple average across all years. This determination is based on the lack of data points for plants over 10 years old.

When considering the average O&M costs per plant as a single data point and then averaging those values, Sargent & Lundy calculated an average O&M cost of $75/kW-year from the FERC data for sites under 5 MW. Using the same method, an average O&M cost of $15/kW-year was calculated from the FERC data for sites over 5 MW.

By comparison, the EMM uses an average O&M value of $28.47/kW-year for all solar PV plants and an average CAPEX value of zero. Neither dataset captures the most recent trends in solar PV technology due to rapid changes in cost, size, and efficiency.

### Solar Thermal

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

### Geothermal

Overall, the geothermal dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Instead, we recommend a simple average be used across the full age range. Sargent & Lundy recommends using the indicated $/kW-year average in Table ES-10 for O&M and CAPEX spending. As shown in the table, it appears the EMM does not currently account for CAPEX or life extension expenditures for geothermal plants.

**Table ES-10 — Geothermal CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr) |
|---|---|---|---|---|
| Geothermal Dataset Results – All Plants | 157.10 | - | 40.94 | 198.04 |
| Existing EMM Value** | 91.66 | 0.00 | 0.00 | 91.66 |

**Source: Internal communication with EIA, February 2018.

### Wind

The dataset supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equations shown in Table ES-11. Age was not a significant predictor of CAPEX spending, although CAPEX was found to vary significantly as a function of capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale.

The CAPEX and O&M values derived from the wind dataset are significantly higher than the existing values used in the EMM. The reasons for this discrepancy are not known without having the data sample used for the EMM values. Neither data sample is stratified by wind technology or turbine size. Neither dataset captures the most recent trends in wind turbine technology due to rapid changes in cost, size, and efficiency.

**Table ES-11 — Wind CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) |
|---|---|---|---|
| Wind Dataset Results – All Plants | 31.66 + (1.22 × age) | 0.00 | 18.29 |
| < 100 MW | 39.08 + (1.12 × age) | 0.00 | 20.48 |
| 100 MW – 200 MW | 23.80 + (1.17 × age) | 0.00 | 16.93 |
| > 200 MW | 26.78 + (0.92 × age) | 0.00 | 13.48 |
| Existing EMM Value* | 29.31 | 0.00 | 0.00 |

*Source: Internal communication with EIA, February 2018.

## RECOMMENDED AREAS FOR FURTHER STUDY

Based on our analyses performed for the update to the EMM treatment of age-related spending, Sargent & Lundy identified several areas that warrant further study, including:

- Impact of regional labor cost differences versus the effects of a regulated/deregulated environment;
- Compatibility of EMM plant technology and size breakdowns and fixed/variable O&M cost breakdowns with proposed EMM updates;
- Identification of the factors supporting consistently high capacity factors over the plant lives at particular coal units; and
- Impact of aging on plant performance (heat rates, capacity derates, etc.). If capacity factors decline, regardless of the causes, this includes examining the impact of the lower capacity factors on plant costs and performance.

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# 1. INTRODUCTION

Sargent & Lundy LLC (Sargent & Lundy) was engaged by the Office of Energy Analysis (OEA) of the U.S. Energy Information Administration (EIA), an agency within the U.S. Department of Energy (DOE), to conduct a study to improve the ability of the Electricity Market Module (EMM) to represent the changing landscape of electricity generation and to more accurately represent costs, which will improve projections for generating capacity, generator dispatch, and electricity prices. The EMM is a submodule within the EIA's National Energy Modeling System (NEMS), a computer-based energy supply modeling system that is used for the EIA's *Annual Energy Outlook* (AEO) and other analyses.

In particular, the purpose of this study was to provide information that may enable the EIA to more accurately represent costs associated with operation of the existing fleet of U.S. generators as they age. This includes capital expenditures (CAPEX) related to ongoing operations as well as potential increases in operations and maintenance (O&M) costs attributable to declining performance due to aging.

The primary focus of our analysis was existing fossil fuel generators. The study also included existing wind, solar, hydro, and other renewable generators. The work scope did not include analysis of nuclear units.

The generating capacity types represented in the EMM that were included in our analysis comprised:

- Coal steam plants
- Gas/oil steam plants
- Gas/oil combined-cycle (CC) plants
- Gas/oil combustion turbines (CTs)
- Conventional hydropower
- Pumped storage – hydraulic turbine reversible
- Solar thermal – central tower
- Solar photovoltaic (PV) – single-axis tracking
- Geothermal
- Wind

This final report is the fourth milestone task of the EMM update project, which is organized as follows:

- Task 1 – Analysis of publicly available information for use in estimating capital costs related to ongoing operations for specified plant types.

- Task 2 – Analysis of publicly available information for use in estimating changes in O&M expenditures due to aging for specified plant types.
- Task 3 – Interim report on assembled aging-related capital and O&M costs.
- Task 4 – Final report on modeling aging-related capital and O&M costs.

# 2. ASSESSMENT METHODOLOGY

## 2.1 BACKGROUND

The EMM currently accounts for power plant aging through a one-time step increase in annual CAPEX. These added expenditures are intended to extend the life or preserve the performance of an existing generator, including repowering, major repairs or retrofits, and/or covering increases in maintenance required to mitigate the adverse effects of aging, including any decreases in plant performance. The portion of the annual CAPEX associated with the step increase is referred as "life extension costs."

As modeled in the EMM, a generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, O&M costs, and annual CAPEX. The average annual CAPEX in the EMM is $0.18 per kilowatt-year (/kW-year) for existing CC plants, $9/kW-year for existing gas/oil steam plants, and $18/kW-year for existing coal plants (in constant 2017 dollars). These amounts are increased to $7.25/kW-year, $16/kW-year, and $25/kW-year, respectively, after a plant reaches 30 years of age.[6] The average annual CAPEX in the EMM for existing CT plants is $1.52/kW-year with no life extension costs. The other generating technologies in the EMM are not currently modeled with either CAPEX or life extension costs.

The existing CAPEX values in the EMM were derived from yearly changes in plant in service accounts reported on the Federal Energy Regulatory Commission (FERC) Form No. 1 ("FERC Form 1").[7] The O&M costs in the EMM are also derived from FERC Form 1. However, FERC Form 1 does not cover merchant power plants or independent power producers (IPPs), leaving a large gap in the data. For example, out of approximately 35,000 generating units in the U.S., roughly 21,000 (60%) are IPPs. The EIA currently extrapolates data from FERC Form 1 to represent all plants covered in the EMM.

Sargent & Lundy's update to the EMM treatment of aging examined the potential adaptation of the EMM to represent changes in age-related spending patterns by various methods. This examination required the following steps:

1. Gathering of in-house data from independent power projects and other plants, in addition to FERC Form 1 data.

[6] Internal communication with EIA, February 2018.
[7] FERC Form 1 is an annual regulatory requirement for major electric utilities, licensees, and others designed to collect non-confidential financial and operational information.

2. Incorporation of O&M and capital spending forecasts by plant owners and operators with firsthand knowledge of plant operating history and future needs, thereby extending the range of plant operating years over which to characterize spending, compared with FERC Form 1 data that is limited to historical data.
3. Removal of capital spending for major modifications relating to environmental compliance, which would be modeled on a case-specific basis.
4. Identification of the most significant variables affecting age-related spending from commonly reported plant data—such as plant capacity (kW), annual generation (megawatt-hours [MWh]), age, fuel type, emission controls, and regulatory environment—using regression analysis.
5. Representation of age-related costs as either fixed ($/kW-year) or variable ($/MWh) according to generating technology and typical maintenance practices.
6. Application of capital spending and/or age-related costs to the EMM representations of long-term fixed O&M, variable O&M, and ongoing capital spending for each generating technology.

The assessment methodology used by Sargent & Lundy for the EMM update included an in-depth process of data validation, data normalization, and statistical testing, which is described in detail in the following subsections.

## 2.2 SOURCES OF COST INFORMATION

### 2.2.1 FERC Form 1 Data

Sargent & Lundy reviewed the FERC Form 1 data through 2016, financial information available from other publicly available sources, and detailed in-house project information with which we are familiar. We assembled a sufficient volume of source material for each technology in order to characterize the distribution of capital and O&M expenditures over the life of a plant.

We obtained the FERC Form 1 data via ABB's Velocity Suite EV Power database. Using the available FERC Form 1 data, we assessed and summarized the "Cost of Plant" components of the data by major plant type category. The "Cost of Plant" components include the following categories of "Electric Plant in Service" accounts in FERC Form 1 data, which have been reported annually since the database's inception:

- Steam Power Generation – Cost of Plant
  - 310 Land and land rights.
  - 311 Structures and improvements.

  - 312 Boiler plant equipment.
  - 313 Engines and engine-driven generators.
  - 314 Turbo generator units.
  - 315 Accessory electric equipment.
  - 316 Miscellaneous power plant equipment
  - 317 Asset retirement costs for steam production plant.
- Hydraulic Power Generation – Cost of Plant
  - 330 Land and land rights.
  - 331 Structures and improvements.
  - 332 Reservoirs, dams, and waterways.
  - 333 Water wheels, turbines, and generators.
  - 334 Accessory electric equipment.
  - 335 Miscellaneous power plant equipment.
  - 336 Roads, railroads, and bridges.
  - 337 Asset retirement costs for hydraulic production plant.
- Other Power Generation – Cost of Plant
  - 340 Land and land rights.
  - 341 Structures and improvements.
  - 342 Fuel holders, producers, and accessories.
  - 343 Prime movers.
  - 344 Generators.
  - 345 Accessory electric equipment.
  - 346 Miscellaneous power plant equipment.
  - 347 Asset retirement costs for other production plant.

The sum of these components includes the original construction cost and all ongoing CAPEX. Therefore, each annual FERC Form 1 submittal includes the cumulative additions to the "Total Cost of Plant" (TCP). Annual changes in the TCP between each submittal year give an indication of the amount of CAPEX for the given year. Sargent & Lundy assessed and summarized these annual changes to derive age-related CAPEX, as discussed in the following subsections.

Sargent & Lundy also assessed and summarized the annual O&M expenditures for each technology as reported under the "Electric Operation and Maintenance Expenses" accounts in FERC Form 1:

- Steam Power Generation – O&M
  - 500 Operation supervision and engineering.
  - 502 Steam expenses.
  - 505 Electric expenses.
  - 506 Miscellaneous steam power expenses.
  - 507 Rents.
  - 509 Allowances.
  - 510 Maintenance supervision and engineering.
  - 511 Maintenance of structures.
  - 512 Maintenance of boiler plant.
  - 513 Maintenance of electric plant.
  - 514 Maintenance of miscellaneous steam plant.
- Hydraulic Power Generation – O&M
  - 535 Operation supervision and engineering.
  - 536 Water for power.
  - 537 Hydraulic expenses.
  - 538 Electric expenses.
  - 539 Miscellaneous hydraulic power generation expenses.
  - 540 Rents.
  - 541 Maintenance supervision and engineering.
  - 542 Maintenance of structures.
  - 543 Maintenance of reservoirs, dams, and waterways.
  - 544 Maintenance of electric plant.
  - 545 Maintenance of miscellaneous hydraulic plant.
- Other Power Generation – O&M
  - 546 Operation supervision and engineering.
  - 548 Generation expenses.
  - 549 Miscellaneous other power generation expenses.
  - 550 Rents.
  - 551 Maintenance supervision and engineering.
  - 552 Maintenance of structures.
  - 553 Maintenance of generating and electric plant.
  - 554 Maintenance of miscellaneous other power generation plant.

The above O&M expenditures are reported for individual power plants. Administrative and general (A&G) expenses in FERC accounts 920 through 935 are reported for the entire utility company. A&G expenses in these accounts were not included in this evaluation because of the significant differences in company sizes, mix of resources, and methods of allocating costs to individual power plants. In a similar manner, corporate-level A&G costs were also excluded from Sargent & Lundy's internal data.

The above FERC accounts 500 to 554 correspond to the following fixed and variable O&M components:

- Fixed O&M
    - Labor
    - Maintenance materials
    - Supplies and miscellaneous expenses
- Variable O&M
    - Consumables (chemicals, water, waste disposal, etc.)
    - Other costs proportional to generating output

The FERC accounts do not explicitly break out labor costs, as most of the accounts include both labor and non-labor expenditures. Likewise, the FERC accounts are not categorized according to fixed and variable cost components. The O&M costs in a given account are combined fixed and variable costs at the reported generating output.

### 2.2.2 Sargent & Lundy Internal Data

In addition, Sargent & Lundy compared publicly available, non-fuel-related financial and cost data with a characterization of proprietary information with which we are familiar, to the extent permissible by applicable confidentiality agreements (information about plant location, equipment type, or plant configuration was never disclosed from the proprietary data). We utilized our knowledge of actual projects to assemble a characterization of life extension/repowering costs from our in-house data.

A large portion of the in-house data used in this report was developed from business plan forecasts that capture actual budgeted costs for scheduled projects as well as longer-term projections. Historical spending data for standalone projects was not usable for this analysis, unless Sargent & Lundy had access to the complete O&M or CAPEX spending totals at a given plant for a given year. For consistent comparisons with other plants over time, each O&M or CAPEX data point needed to represent a comprehensive total of all spending projects.

### 2.2.3 Other Data Sources

Other publicly available data sources were searched, including regulated utility filings with public utility commissions, routine financial reports for publicly traded companies, utility integrated resource plans, data reported by various municipalities and electric cooperatives, and requests for proposals (RFPs) for plant improvements at public power entities. Cost data from each of these sources was found to be unsuitable for this study for one or more of the following reasons:

- Cost data was for initial capital investment costs only, with no O&M or ongoing CAPEX spending reported;
- Annual O&M or annual CAPEX amounts were for limited purposes and not representative of a complete year; and/or
- Annual O&M and annual CAPEX amounts were aggregated across business units and not assigned to specific plants.

Several publications or studies of power plant aging and life extension costs were used, which are cited herein.

## 2.3 DATA VALIDATION

Sargent & Lundy's approach to validating the FERC Form 1 data involved the following steps (note that capitalized words are proper FERC Form 1 terms):

1. For each Plant/Prime Mover combination (e.g., steam turbine, CC, simple-cycle CT), determine the difference between the prior and current year TCP reported in the FERC data. Note that a plant can have multiple prime movers on site (e.g., CT units and steam turbine units). Fortunately, that data is reported separately.
2. Flag and invalidate any years where the difference is negative (i.e., a decreasing value of the TCP).
3. Identify if the TCP difference is significantly due to asset retirement costs. If so, flag this plant reporting year consider it invalid, as capital would have been spent on non-aging items.
4. Identify if there has been any year-to-year change in nameplate capacity. If so, flag this plant reporting year and consider it invalid, because the TCP would be assumed to be spent on an expansion or addition.
5. Identify if any sulfur dioxide ($SO_2$), nitrogen oxide ($NO_X$), particulate matter (PM), or mercury (Hg) control equipment was installed for the plant reporting year. If so, flag that plant reporting year and consider it invalid, because capital would have been spent on non-aging items. The year

prior to or after the actual emissions control installation date is sometimes flagged as well, because of when the spending occurred (this is usually a judgement call).

6. Identify if any unit at the plant has been retired in a plant reporting year. If so, flag that plant reporting year and consider invalid, because capital would have been spent on non-aging items. Also, if the plant's TCP dropped significantly the last few years before retirement, flag those plant reporting years and consider them invalid.
7. Cross-check if any additional units at the plant site (using the same technology) show too great of time duration between installed dates of the units. If the first unit and the last unit installed is greater than 10 years apart, then flag the data and consider it invalid, because the TCP difference would not reflect the actual age of the plant (considered to be the age of the first unit). This was flagged as "Removed due to non-equal units at site."
8. If any TCP is reported to be zero for most of all of the reporting years of the plant, consider the data invalid.
9. If the TCP difference is highly volatile, flag and invalidate at discretion. For example, if one year TCP drops from $2,000/kW-year to $1,000/kW-year and then back to $2,000/kW-year in the year after, this would be considered highly volatile for those two reporting years.
10. If a reporting plant has only one or two years of reported TCP data, flag the plant and do not use its data.
11. If any plant reports negative Total O&M Costs, flag that year and do not use it.
12. Use only data that is valid for both CAPEX spending and O&M spending in the analysis of combined CAPEX and O&M spending. Otherwise, analyze CAPEX spending and O&M spending separately. Sargent & Lundy found that a large portion of the data points determined to be valid for CAPEX spending were also valid for O&M spending.

The resulting data points from this validation process are summarized in Table 2-1.

For each year of plant data, we also compiled the associated nameplate capacity (MW) and annual generation (MWh). EIA Form 860 was used to confirm the plant technology, environmental equipment, year in service, and other attributes.

## Table 2-1 — Summary of Valid Data Points

| Technology / (Dataset Identifier) | Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|---|
| | | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| Coal (10) | All MW | All | 3,713 | 3,098 | 3,109 | 655 | 615 |
| | < 500 MW | All | 1,592 | 1,274 | 1,284 | 318 | 318 |
| | 500 MW – 1,000 MW | All | 986 | 689 | 689 | 337 | 297 |
| | 1000 MW – 2,000 MW | All | 813 | 813 | 814 | 0 | 0 |
| | > 2,000 MW | All | 322 | 322 | 322 | 0 | 0 |
| | All MW | < 50% | 965 | 889 | 896 | 76 | 76 |
| | All MW | > 50% | 2,748 | 2,209 | 2,213 | 579 | 539 |
| Gas/Oil Steam (20) | All MW | All | 2,220 | 2,204 | 2,226 | 20 | 16 |
| | < 500 MW | All | 1,377 | 1,361 | 1,366 | 20 | 16 |
| | 500 MW – 1,000 MW | All | 488 | 488 | 489 | 0 | 0 |
| | > 1,000 MW | All | 355 | 355 | 355 | 0 | 0 |
| Gas/Oil Combined Cycle (30) | All MW | All | 1,367 | 980 | 981 | 408 | 387 |
| | < 500 MW | All | 764 | 462 | 463 | 304 | 302 |
| | 500 MW – 1,000 MW | All | 547 | 462 | 463 | 104 | 85 |
| | > 1,000 MW | All | 177 | 177 | 177 | 0 | 0 |
| | All MW | < 50% | 843 | 661 | 662 | 203 | 182 |
| | All MW | > 50% | 524 | 319 | 319 | 205 | 205 |
| Gas/Oil Combustion Turbine (40) | All MW | All | 5,041 | 4,905 | 4,949 | 437 | 136 |
| | < 100 MW | All | 2,873 | 2,873 | 2,911 | 189 | 0 |
| | 100 MW – 300 MW | All | 1,341 | 1,239 | 1,248 | 177 | 102 |
| | > 300 MW | All | 901 | 867 | 875 | 71 | 34 |
| Conventional Hydroelectric (50) | All MW | All | 2,179 | 2,179 | 2,180 | 0 | 0 |
| | < 100 MW | All | 1,272 | 1,272 | 1,272 | 0 | 0 |
| | 100 MW – 500 MW | All | 924 | 924 | 925 | 0 | 0 |
| | > 500 MW | All | 41 | 41 | 41 | 0 | 0 |

| Technology / (Dataset Identifier) | Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|---|
| | | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| Pumped Storage Hydroelectric (55) | All MW | All | 226 | 226 | 227 | 0 | 0 |
| | < 100 MW | All | 12 | 12 | 12 | 0 | 0 |
| | 100 MW – 500 MW | All | 88 | 88 | 88 | 0 | 0 |
| | > 500 MW | All | 126 | 126 | 126 | 0 | 0 |
| Solar Thermal (60) | | | 0 | | | | |
| Solar Photovoltaic (65) | All MW | All | 57 | 410 | 57 | 0 | 0 |
| Geothermal (70) | | | | | | | |
| Wind Turbine (80) | All MW | All | 310 | 310 | 310 | 270 | 0 |
| | < 100 MW | All | 174 | 174 | 174 | 165 | 0 |
| | 100 MW – 200 MW | All | 91 | 91 | 91 | 56 | 0 |
| | > 200 MW | All | 51 | 51 | 51 | 73 | 0 |

Note: A data point is one reported value for one year by one plant, i.e., a plant that reports values for 25 years will have 25 data points.

## 2.4 DATA NORMALIZATION

Sargent & Lundy developed a Microsoft Excel model template for compiling and normalizing all of the CAPEX and O&M data, subsequent to the initial review and validation steps outlined in the previous sections. The data normalization consisted of the following steps:

**Step 1:** Assign data "identifiers" for each plant:

Technology ID:

- 10 = Coal Steam Plants
- 20 = Gas/Oil Steam Plants
- 30 = Gas/Oil CC Plants
- 40 = Gas/Oil CTs
- 50 = Conventional Hydropower; Pumped Storage – Hydraulic Turbine Reversible
- 60 = Solar Thermal – Central Tower;
- 65 = Solar PV – Single-Axis Tracking
- 70 = Geothermal
- 80 = Wind

Data source:

- 1 = FERC Form 1
- 2 = Sargent & Lundy Internal Data
- 3 = Other Public Source

**Step 2:** Enter basic information for each plant:

- Year of commercial operation date (COD)
- End year of project life or forecast period
- Nameplate capacity (MW)
- Summer net capacity (MW)

**Step 3:** Adjust pricing basis for raw data:

- If provided in current dollars, adjust to 2017 dollars
- If provided in 2017 dollars, do not adjust
- If provided in constant dollars of another reference year, adjust to 2017 dollars

**Step 4:** Enter annual data for each plant (any available data from 1980 to 2060, historical or forecasted by plant owner):

- Plant MW (summer)
- Annual MWh
- Annual O&M (from FERC Form 1)
- Annual O&M (from other sources)
- Annual CAPEX (from FERC Form 1)
- Annual CAPEX (from other sources)
- Annual environmental compliance costs

Using the inputs from Steps 1-4 above, the “Normalizer” worksheet derives the following for each plant:

- Annual O&M in 2017 $/kW-year versus age (years from COD)
- Annual CAPEX in 2017 $/kW-year versus age (years from COD)
- Annual O&M + CAPEX in 2017 $/kW-year versus age (years from COD)

The output worksheets (“O&M,” “CAPEX,” and “O&M + CAPEX”) each have the following user-selected filters:

- Technology ID (10, 20, 30, etc.)

- Data source (1,2, or 3)
- MW range (low, high)
- Outlier maximum $/kW
- Annual O&M + CAPEX in 2017 $/kW-year versus age (years from COD)

Each output worksheet ("O&M," "CAPEX," and "O&M + CAPEX") calculates the following for a given user-defined set of filters:

- $/kW-year (2017 dollars) versus age
- Statistical tests of linear curve fit: annual spending in 2017 $/kW-year = $/kW-year (y-intercept) + [constant × age (years from COD)]
- Average $/kW-year (2017 dollars) for age bands (10-year bands, 30-year bands, and all-years band)

In all cases, the yearly values are expressed in constant 2017 price levels and increase annually with the inflation rate.

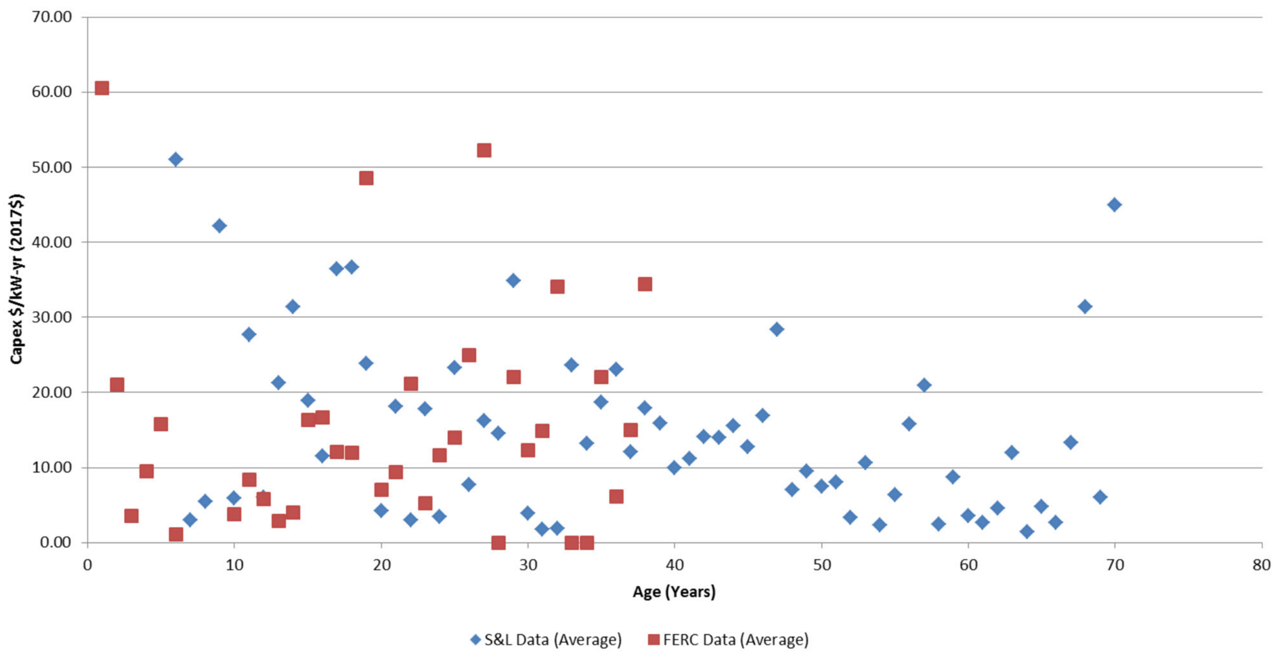
## 2.5 STATISTICAL TESTS

### 2.5.1 Consistency of FERC Form 1 and Sargent & Lundy Internal Data

FERC Form 1 data only covers historical data for utilities that are required to file and does not include the owners' projected expenditures or any data for merchant plants and independent power plants. Most of Sargent & Lundy's proprietary data, on the other hand, covers the owners' projected expenditures for utility plants and includes both historical and projected expenditures for merchant plants and independent power plants. The data points from both data sources were judged to be complementary and combined as a single dataset.

The compatibility of the FERC data and Sargent & Lundy internal data is illustrated by the CAPEX spending for a sample of 500-MW coal plants (Figure 2-1). This example is based on a sample of 11 plants from the Sargent & Lundy data and 12 plants from the FERC data, each sample having an average plant capacity of approximately 500 MW and an average age of approximately 30 years. Each data point in the figure is the average value for all the plants that have a valid data point at the given plant age. There are a total of 175 valid data points for the FERC plants and 200 valid data points for the Sargent & Lundy plants. In this particular sample, all of the FERC data is historical and all of the Sargent & Lundy data is owners' projected expenditures.

**Figure 2-1 — CAPEX vs. Age for 500-MW Coal Plants – FERC and Sargent & Lundy Data**



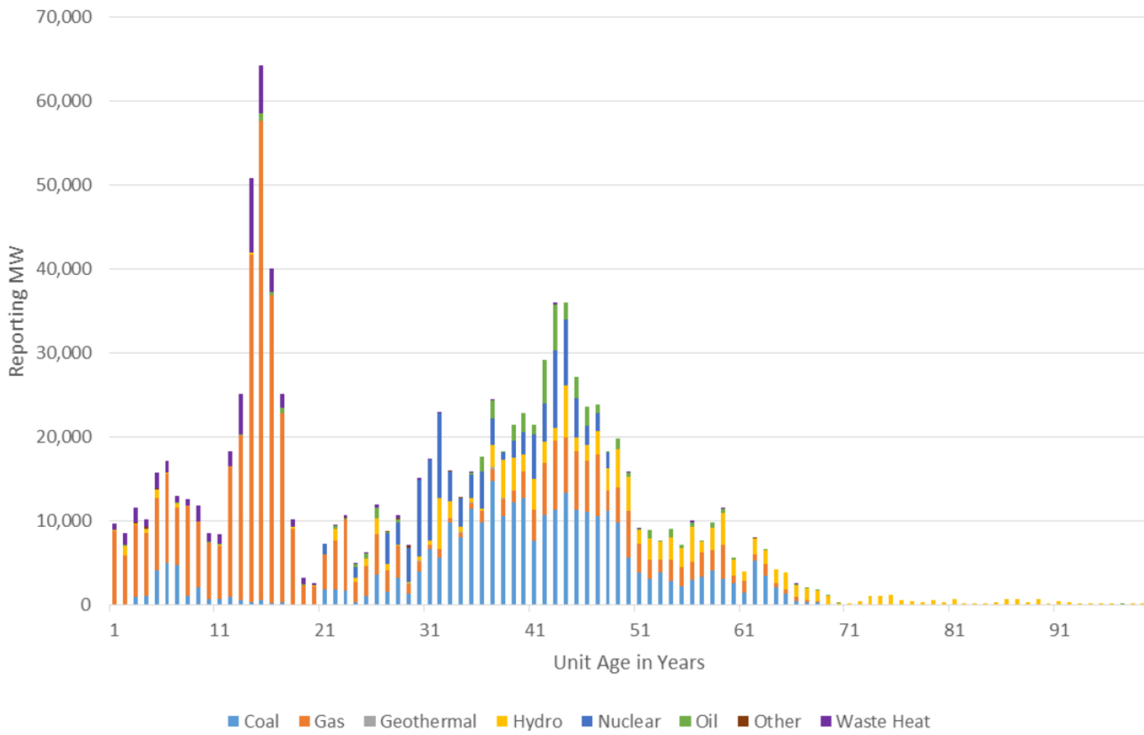

As discussed in Section 0, CAPEX spending for coal plants does not follow a uniform pattern for all plants. For example, different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

For some utility plants, data was available from both FERC Form 1 and proprietary data. The historical O&M and CAPEX spending for these plants were examined in each year to verify their consistency.

The distribution of valid data points for each technology versus age (years from COD in which the spending occurs) was examined to verify consistency with typical plant ages nationwide. Figure 2-2 shows a recent distribution of the U.S. power plant fleet by unit age and fuel type as reported by FERC[8]. This distribution indicates a large portion of coal-fired capacity with ages of 30-50 years, and a large portion of gas-fired capacity (mostly CT or CC) with ages under 20 years. The valid data points assembled in this report were found to be representative of these major age and technology cohorts.

[8] North American Electric Reliability Corporation, *State of Reliability 2017*, June 2017 (p.116)

**Figure 2-2 — U.S. Power Plant Fleet Capacity by Age and Fuel Type**




A recent study found that the average age of the U.S. generator fleet has increased significantly over time, due in part to regulatory uncertainty in a deregulated market environment. At the same time, the average expected physical life of the fleet has been decreasing as a result of new investments in smaller, shorter-lived capacity. This has been a means of mitigating the regulatory risk of more limited stranded cost recovery mechanisms.[9] In another recent study, this one on the causes of power plant retirements, the strongest predictors of retirements were found to be $SO_2$ emission rates, planning reserve margins, variations in load growth or contraction, the age of older thermal plants, the ratio of coal to gas prices, and delivered natural gas prices. The impacts of annual CAPEX and O&M spending on retirement decisions were not specifically identified.[10]

### 2.5.2 Significance of Plant Age on Annual Capital and O&M Expenditures

For each technology group, Sargent & Lundy performed a regression analysis on the O&M spending, CAPEX spending, and combined O&M plus CAPEX spending using the following linear equation:

- Annual spending in 2017 \$/kW-year = \$/kW-year (y-intercept) + (constant × age)

[9] Rode, D., Fischbeck, P., and Paez, A., "Power Plant Lives and their Policy Implications," *Energy Policy*, 106 (2017) 222-232, April 1, 2017.
[10] Mills, A., Wiser, R., and Seel, J, "Power Plant Retirements: Trends and Possible Drivers," Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, November 2017.

The purpose of the regression analysis was to determine whether plant age is a statistically significant predictor of annual spending. The regression coefficient for age measures the change (+ or -) in annual spending as a function of plant age, measured as the number of years from the COD. Its statistical significance is measured by the p-value, which tests the null hypothesis that the coefficient is equal to zero (i.e., has no effect on spending).

The R-squared ($R^2$) statistic ("coefficient of determination") is an indication of the goodness of fit of the regression equation to the real data points. A low $R^2$ indicates that the regression equation explains a relatively small amount of the variability of the data around its mean. A low p-value ($< 0.05$) indicates that the age coefficient is statistically significant, regardless of the $R^2$ statistic. A low p-value corresponds approximately to a t-value that is greater than 2 or less than -2. For higher p-values, the simple average $/kW-year per year may be a more appropriate estimation for a given age band (e.g., 20-year bands and all-years band). Depending on the characteristics of the dataset, especially the number of data points, Sargent & Lundy applied engineering judgement (as further described in each section that follows) in our recommendations.

### 2.5.3 Autocorrelation of Time Series Data

In addition to the correlation between annual spending and plant age, an autocorrelation may also exist between spending in a given year and spending in previous years. Autocorrelation commonly occurs with time series data. If statistical tests verify the presence of autocorrelation, a lagged (autoregressive) variable may be added to improve the goodness of fit ($R^2$) of the regression model. Models with this functional form are referred to as "autoregressive integrated moving average" (ARIMA) models.

ARIMA models are typically constructed for the purpose of predicting the future from a given point in time, based on correlations with historical values and other exogenous variables. The functional form of an ARIMA model may better capture curvilinear or cyclical data trends and therefore improve the goodness of fit. For the purposes of this study, an ARIMA model was not necessary or appropriate. The datasets in this analysis already capture plant O&M and CAPEX spending patterns throughout a typical plant lifespan. The purpose of this study was to represent costs for generators as they age, and not to predict future spending from a given point in time.

# 3. COAL STEAM

## 3.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for coal steam plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M expenditures:
  - 456 plants in FERC data and 32 plants from Sargent & Lundy internal data
  - 3,098 valid data points in FERC data, 655 valid data points in Sargent & Lundy internal data
- CAPEX:
  - 457 plants in FERC data and 29 plants from Sargent & Lundy internal data
  - 3,109 valid data points in FERC data, 615 valid data points in Sargent & Lundy internal data

The coal steam data was broken down by plant MW capacity and average capacity factor—as summarized in Table 3-1—for the regression analysis shown in Appendix A.

**Table 3-1 — Coal Steam Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 3,713 | 3,098 | 3,109 | 655 | 615 |
| < 500 MW | All | 1,592 | 1,274 | 1,284 | 318 | 318 |
| 500 MW – 1,000 MW | All | 986 | 689 | 689 | 337 | 297 |
| 1,000 MW – 2,000 MW | All | 813 | 813 | 814 | 0 | 0 |
| > 2,000 MW | All | 322 | 322 | 322 | 0 | 0 |
| All MW | < 50% | 965 | 889 | 896 | 76 | 76 |
| All MW | > 50% | 2,748 | 2,209 | 2,213 | 579 | 539 |

Table 3-2 below identifies the relative effects in the data validation process of the top three data filters on the number of valid data points. These filters are described as follows:

- Change in Capacity: A change in nameplate capacity of 20% or more during the reported time of the unit. Data points prior to the change in capacity are no longer comparable to the data points after the change in capacity, so the entire unit was filtered out.
- Negative Change in Total Cost: Any year with a decrease in the cumulative historical capital cost reported in the FERC data was not included.
- Environmental Retrofit: Data points in years where $SO_2$, $NO_X$, PM, or Hg removal equipment was installed were filtered out.

**Table 3-2 — Effect of Data Validation Filters on Coal Data Points**

| Coal Steam – FERC Dataset | Data Points |
|---|---|
| Total Data Points, Unfiltered | 6,699 |
| Total Data Points, Filtered Out | 3,774 |
| **Top Three Filters** | |
| Change in Capacity | 1,659 |
| Negative Change in Total Cost | 889 |
| Environmental Retrofit | 599 |
| **Total Data Points, Valid (FERC Only)** | **2,925** |

## 3.2 SUMMARY OF RESULTS

### 3.2.1 Recommended CAPEX Values

The analysis of the coal steam dataset (Appendix A) identified two significant variables affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): age and flue gas desulfurization (FGD). Variables not having a significant effect on annual changes in real CAPEX spending (on a constant $/kW-year basis) were: plant capacity (kW), fuel type, and regulatory environment. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table 3-3 below compares the new CAPEX values derived from the coal steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

**Table 3-3 — Coal Steam CAPEX Results – All MW, All Capacity Factors**

| Net Total CAPEX (2017 $/kW-year) | $/kW-yr (Years 1-10) | $/kW-yr (Years 10-20) | $/kW-yr (Years 20-30) | $/kW-yr (Years 30-40) | $/kW-yr (Years 40-50) | $/kW-yr (Years 50-60) | $/kW-yr (Years 60-70) | $/kW-yr (Years 70-80) |
|---|---|---|---|---|---|---|---|---|
| New Value – No FGD* | 17.16 | 18.42 | 19.68 | 20.94 | 22.20 | 23.46 | 24.72 | 25.98 |
| New Value – with FGD* | 22.84 | 24.10 | 25.36 | 26.62 | 27.88 | 29.14 | 30.40 | 31.66 |
| Existing EMM Value | 17.55 | 17.55 | 17.55 | 24.62 | 24.62 | 24.62 | 24.62 | 24.62 |

*Calculated from the following regression equation to the midpoint of the given age band:

**Annual CAPEX spending in 2017 $/kW-year = 16.53 + (0.126 × age) + (5.68 × FGD)**
**Where FGD = 1 if a plant has FGD; zero otherwise**

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most coal steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant are not absolute, but rather indicative of when a coal plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair.

The new values also account for CAPEX relating to FGD. An FGD system tends to be capital-intensive to own and operate. The corrosive environment of chemicals and reagents significantly reduces the life of equipment such as pumps, mills, nozzles, valves, etc. These components must be replaced more frequently compared with plants without FGD.

Table 3-4 below provides indicative typical industry-standard frequencies for repairs and replacement of major equipment within a coal plant.

**Table 3-4 — Coal Plant Indicative Typical CAPEX Projects and Intervals**

| Project Description | Typical Frequency of Repairs/Replacement from COD (Years) |
|---|---|
| **Boiler** | |
| Coal mills and exhausters, burner tips and ignitors | 5 |
| Lower nose tube, burner panels, economizer banks, air heater tubes, and baskets | 15 |
| Lower and upper waterwalls, superheater and reheater horizontal sections and pendants, economizer header, coal feeders, mill motors | 20 |
| Superheater and reheater header, feedwater supply piping | 25 |
| Mud and steam drums | 30 |
| **Turbine and Generator** | |
| Control valves, nozzle block | 12 |
| Electro-hydraulic control system (EHC), governor, turbine controls, generator rotor, turbine lubrication pumps | 15 |
| Stop valves, low-pressure (LP) turbine and blades, LP casing/diaphragms, | 20 |
| Steam chest, high-pressure/intermediate-pressure (HP/IP) turbine with blades, HP/IP casing/diaphragm, generator stator, exciter | 25 |
| HP/IP rotor, LP rotor, isophase | 30 |
| **Balance of Plant** | |
| Condensate pumps, cooling tower fill, cooling tower fan drives and blades, conveyor belts, conveyer idlers/pulleys/motors, coal crushing equipment | 10 |
| Slag conveyors and tanks | 12 |
| Induced draft (ID) fans, electrostatic precipitator (ESP) casing, ESP plates/wires, deaerator, circulating water pumps, boiler feed pumps, distributed control system (DCS)/unit controls, boiler master/combustion controls, coal handling dust control system | 15 |
| Forced draft (FD) fans, primary air (PA) fans, fan motors, windbox and ductwork, ESP transformer/rectifier (TR) sets and rappers, condenser valves and cleaner system, LP feedwater heaters, HP feedwater heaters, gland coolers, conveyor structures, coal unloading equipment, fuel oil heaters, and delivery pumps | 20 |
| Condenser retube, deaerator storage tank, vacuum pumps/steam air ejectors, pump motors | 25 |
| Main power transformer, auxiliary transformer | 30 |

### 3.2.2 Recommended O&M Values

The analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in $/kW-year, while variable O&M is typically expressed in $/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

O&M costs for the coal steam plants include a significant variable component. By definition, variable O&M costs are proportional to plant generation and are typically expressed in $/MWh. As previously mentioned, the variable O&M component cannot be clearly delineated from the total reported O&M in the FERC Form 1 data. For this assessment, the variable component was combined with the fixed component and expressed in $/kW-year. The combined total O&M in the coal steam plant dataset for this analysis was found to be nearly equivalent to the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (Table 3-5).

**Table 3-5 — Coal Steam O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh)* | Variable O&M (2017 $/kW-yr)** | Total O&M (2017 $/kW-yr)** |
|---|---|---|---|---|
| Coal Steam Dataset Results – All Plants | 36.81 | 1.78 | 9.20 | 46.01 |
| < 500 MW | 44.21 | 1.78 | 9.20 | 53.41 |
| 500 MW – 1,000 MW | 34.02 | 1.78 | 9.20 | 43.22 |
| 1,000 MW – 2,000 MW | 28.52 | 1.78 | 9.20 | 37.72 |
| > 2,000 MW | 33.27 | 1.78 | 9.20 | 42.47 |
| Existing EMM Value*** | 40.63 | 1.78 | 9.20 | 49.83 |

*Fixed and variable split is estimated using the existing EMM variable O&M cost of $1.78/MWh.
**Calculated at the coal steam dataset average capacity factor of 59%.
***Source: Internal communication with EIA, February 2018.

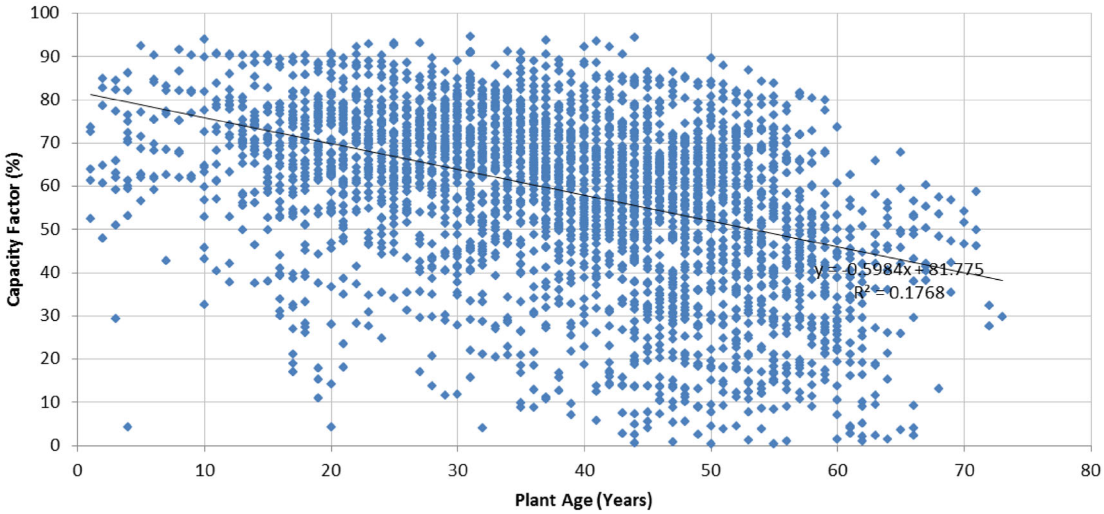
CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

### 3.2.3 Effect of Plant Capacity Factor

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure 3-1.

**Figure 3-1 — Capacity Factor vs. Age for All Coal Plants**




### 3.2.4 Effect of External Market Conditions

The declining capacity factors with age may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for coal steam plants include:

- Competition with lower gas prices and more efficient gas turbines
- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some coal steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.[11]

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient coal steam plants would likely retire under the following circumstances:

[11] Kumar, N., Besuner, P., Lefton, S., and Agan, D., *Power Plant Cycling Costs*, National Renewable Energy Laboratory, April 2012.

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

Some of the older coal steam plants (23 in this data sample) maintained consistently high capacity factors throughout their lives, with no real increase in spending. These high capacity factor plants had an installed capacity ranging from 70 MW to 2,400 MW, with an average of 850 MW and an average COD of 1961. These plants are slightly larger and older, on average, than the entire dataset of coal steam plants, which have an average installed capacity of 720 MW and an average COD of 1964. Table 3-6 shows the average capacity factors and O&M and CAPEX spending for the entire dataset of coal steam plants compared with the older consistently high capacity factor plants.

**Table 3-6 — High Capacity Factor Coal Plants – Spending Comparison**

| | Average – All Years | Years 1-20 | Years 20-40 | Years 40-80 |
|---|---|---|---|---|
| Capacity Factor – All Plants | 59.1% | 66.8% | 64.5% | 52.9% |
| Capacity Factor – High CF Plants | 74.0% | - | 72.8% | 74.4% |
| O&M – All Plants (2017 $/kW-yr) | 46.01 | 53.90 | 40.06 | 48.77 |
| CAPEX – All Plants (2017 $/kW-yr) | 22.78 | 17.92 | 26.20 | 21.25 |
| Total – All Plants (2017 $/kW-yr) | 68.67 | 71.86 | 66.25 | 69.82 |
| O&M – High CF Plants (2017 $/kW-yr) | 36.65 | - | 31.07 | 38.78 |
| CAPEX – High CF Plants (2017 $/kW-yr) | 20.26 | - | 23.13 | 19.16 |
| Total – High CF Plants (2017 $/kW-yr) | 57.02 | - | 54.20 | 58.10 |

Market conditions at the older, high capacity factor plants may have led to fewer competing resources, which would support higher levels of dispatch and higher capacity factors. In addition, lower cycling requirements at those plants would have reduced spending requirements.

### 3.2.5 Effect of Regulatory Environment

Owners of coal steam plants in deregulated states were found to have no aversion to capital spending compared to plant owners in regulated states (see Appendix A). Some of the difference may be due to higher labor costs in many of the deregulated states. This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending was not apparent at this level of detail.

### 3.2.6 Effect of Fuel Characteristics

Sargent & Lundy's regression analysis compared CAPEX spending for coal steam plants with bituminous and subbituminous coal types (Appendix A). The results indicate that average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

# 4. GAS/OIL STEAM

## 4.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil steam plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 283 plants in FERC data and four plants from Sargent & Lundy internal data
  - 2,204 valid data points in FERC data, 20 valid data points in Sargent & Lundy internal data
- CAPEX
  - 283 plants in FERC data and four plants from Sargent & Lundy internal data
  - 2,226 valid data points in FERC data, 16 valid data points in Sargent & Lundy internal data

The gas/oil steam data was broken down by plant MW capacity, as summarized below in Table 4-1, for the regression analysis shown in Appendix B.

**Table 4-1 — Gas/Oil Steam Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 2,220 | 2,204 | 2,226 | 20 | 16 |
| < 500 MW | All | 1,377 | 1,361 | 1,366 | 20 | 16 |
| 500 MW – 1,000 MW | All | 488 | 488 | 489 | 0 | 0 |
| > 1,000 MW | All | 355 | 355 | 355 | 0 | 0 |

## 4.2 SUMMARY OF RESULTS

### 4.2.1 Recommended CAPEX Values

Sargent & Lundy's analysis of the gas/oil steam dataset (Appendix B) identified only one significant variable affecting annual changes in real CAPEX spending (on a constant $/kW-year basis): plant capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale. When CAPEX spending was expressed on a constant $/MWh basis, it was significantly related to age, primarily as a result of declining MWh generation with age.

Table 4-2 compares the new CAPEX values derived from the gas/oil steam dataset with the CAPEX values currently used in the EMM. The new CAPEX values are similar in magnitude with the current EMM values over the long term, except that the new values follow a continuous pattern rather than a step pattern. As discussed below, the new values include life extension projects that occur throughout the plant life, including the first 30 years of operation.

**Table 4-2 — Gas/Oil Steam CAPEX Results**

| Plant Size | Net Total CAPEX (2017 $/kW-year) | |
|---|---|---|
| | Years 1-30 | Years 30-80 |
| Gas/Oil Steam Dataset Results – All Plants | 15.96 | 15.96 |
| New Value: < 500 MW | 18.86 | 18.86 |
| New Value: 500 MW – 1,000 MW | 11.57 | 11.57 |
| New Value: > 1,000 MW | 10.82 | 10.82 |
| Existing EMM Value | 9.14 | 16.21 |

"Life extension costs" in the existing CAPEX values are covered by the step increase after year 30. Life extension costs in the new CAPEX values are distributed throughout the plant life. This is a result of discretionary spending, which is a common practice for most gas/oil steam plants. Different plants might incur the same type of expense at different points in time due to differences in plant-specific economic, locational, or operational circumstances.

Typical industry-standard frequencies for repairs and replacement of major equipment within a gas/oil steam plant are not absolute, but rather indicative of when a gas/oil steam plant may be required to perform the work, based on manufacturer experience. An owner may choose to perform the work early, if they have an available outage, or defer if, after inspection, the equipment appears to be capable of continued operation without repair. Typical industry-standard frequencies for repairs and replacement of major equipment are similar to those of coal units, as presented in the previous section.

The use of a constant annual value on the modeling of annual CAPEX would be similar to representing a major maintenance reserve account (MMRA), which is commonly used for non-recourse financing of power projects. MMRAs are usually required by power project lenders over the tenor of debt as protection against maintenance spending uncertainty. An MMRA is typically funded by annual contributions drawn from a project's cash flow, sometimes as a uniform annual amount. Annual contribution levels are based on estimated long-term maintenance expenditure patterns. Over the long term, annual contributions represent a smoothed version of irregular actual annual values.

The use of a long-term average value also recognizes the inherent variability in long-term spending patterns for any given plant. Since the EMM is a large-scale model, it is conceptually designed to represent plant types as averages rather than as individual plants. When summed across a large number of plants in a utility system, some of the variability in annual expenditure patterns would tend to even out. The level of accuracy between average values and year-specific values for a given plant type is nearly equivalent in large-scale models.

### 4.2.2 Recommended O&M Values

The analysis required an understanding of the cost breakdowns in the reported data between 1) capitalized (CAPEX) and expensed (O&M) cost components and 2) fixed O&M and variable O&M cost components. From a system modeling perspective, CAPEX and fixed O&M costs are typically expressed in $/kW-year, while variable O&M is typically expressed in $/MWh. Normalized cost breakdowns in these units are necessary for compatibility with the EMM.

O&M costs for the gas/oil steam plants include a significant variable component, although typically smaller than coal units. The combined total O&M in the gas/oil steam plant dataset for this analysis was found to be somewhat lower than the existing combined total O&M representation in the EMM, which already includes the necessary $/MWh variable O&M breakout (see Table 4-3). However, the variable O&M of $8.23/MWh in the EMM is much higher than values Sargent & Lundy has observed in actual gas/oil steam plants and should not be higher than the variable O&M of $1.78/MWh in the EMM used for the coal units.

**Table 4-3 — Gas/Oil Steam O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh)* | Variable O&M (2017 $/kW-yr)** | Total O&M (2017 $/kW-yr)** |
|---|---|---|---|---|
| Gas/Oil Steam Dataset Results – All Plants | 24.68 | 1.00 | 1.84 | 26.52 |
| < 500 MW | 29.73 | 1.00 | 1.84 | 31.57 |
| 500 MW – 1,000 MW | 17.98 | 1.00 | 1.84 | 19.82 |
| > 1,000 MW | 14.51 | 1.00 | 1.84 | 16.35 |
| Existing EMM Value*** | 19.68 | 8.23 | 15.14 | 34.82 |

*Fixed and variable split is estimated using an approximate value for variable O&M of $1.00/MWh based on confidential projects.
**Calculated at the gas/oil steam dataset average capacity factor of 21%.
***Source: Internal communication with EIA, February 2018.

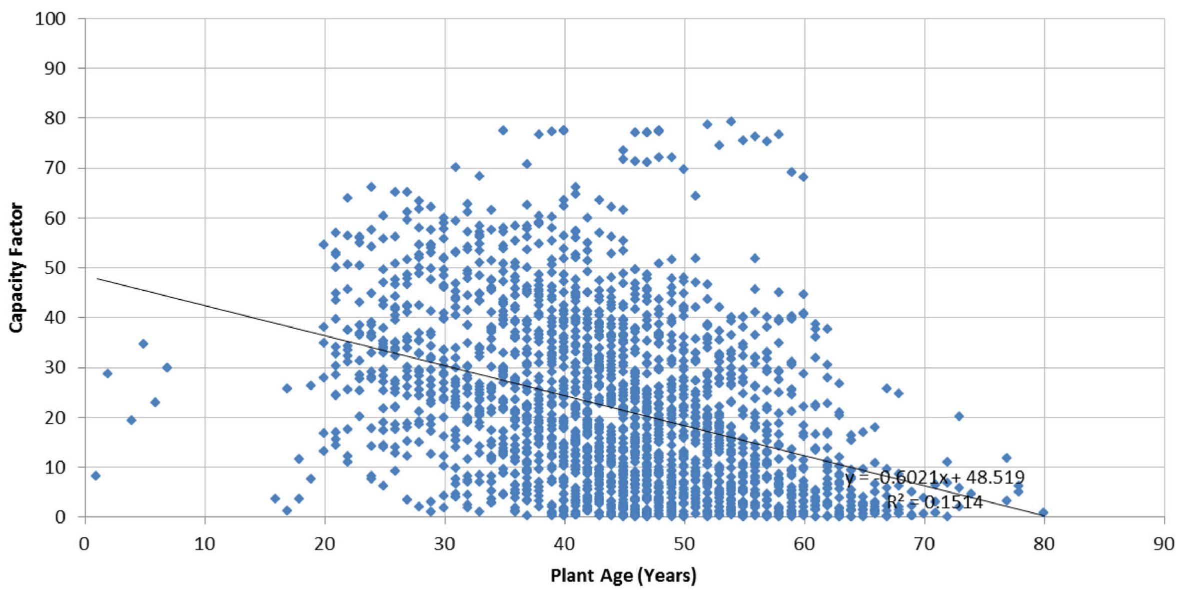
CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

### 4.2.3 Effect of Plant Capacity Factor

CAPEX and O&M spending for the gas/oil steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time, as shown in Figure 4-1.

**Figure 4-1 — Capacity Factor vs. Age for All Gas/Oil Steam Plants**




### 4.2.4 Effect of External Market Conditions

The declining capacity factors with age may have been a result of external market conditions and/or declining plant performance. These are areas for further exploration.

External market conditions over the same time period that may have contributed to lower capacity factors for gas/oil steam plants include:

- Competition with more efficient gas turbines

- Competition with renewable energy having lower dispatch costs
- Lower load growth due to increased amounts of energy efficiency and distributed resources

For some gas/oil steam plants, the decline in capacity factor was also a result of less efficient heat rates, increased component failures, and increased outage rates over time. A major contributor to this decline in performance is often a result of increased cycling operation. Increased cycling leads to higher O&M and CAPEX spending over time.

External market conditions may have also reduced the number of data points with higher age-related spending, due to plant retirements. The least efficient gas/oil steam plants would likely retire under the following circumstances:

- Lower efficiency may contribute to less frequent dispatch and more cycling, leading to more component failures and higher spending
- Less frequent dispatch reduces hours of operation and power sales
- Lower power sales income may not adequately cover plant fixed costs

# 5. GAS/OIL COMBINED CYCLE

## 5.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil CC plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 144 plants in FERC data and 20 plants from Sargent & Lundy internal data
  - 980 valid data points in FERC data, 408 valid data points in Sargent & Lundy internal data
- CAPEX
  - 142 plants in FERC data and 17 Sargent & Lundy proprietary plants with valid data
  - 981 valid data points in FERC data, 387 valid data points in Sargent & Lundy internal data

The gas/oil CC data was broken down by plant MW capacity and average capacity factor, as summarized below in Table 5-1, for the regression analysis shown in Appendix C.

**Table 5-1 — Gas/Oil CC Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 1,367 | 980 | 981 | 408 | 387 |
| < 500 MW | All | 764 | 462 | 463 | 304 | 302 |
| 500 MW – 1,000 MW | All | 547 | 462 | 463 | 104 | 85 |
| > 1,000 MW | All | 177 | 177 | 177 | 0 | 0 |
| All MW | < 50% | 843 | 661 | 662 | 203 | 182 |
| All MW | > 50% | 524 | 319 | 319 | 205 | 205 |

## 5.2 SUMMARY OF RESULTS

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CC plants represents a series of capital projects throughout the plant life, which includes projects for "life extension." Most CAPEX spending for gas/oil CC plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CC plants is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs (described in Section 4.2.1), major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant $/MWh with annual escalation.

Table 5-2 compares the new CAPEX and O&M values derived from the gas/oil CC dataset with the values currently used in the EMM. As previously mentioned, the combined CAPEX and O&M in the dataset would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, some of the EMM values are higher than values Sargent & Lundy has observed in actual CC plants, as detailed below:

- The EMM fixed and variable O&M costs for CC plants are reasonable for smaller CC installations (< 500 MW) but high for larger plants.
- The EMM CAPEX addition of $7/kW-year after 30 years of operation should not be represented as a fixed cost. As previously mentioned, age-related costs would be built into the $/MWh variable O&M and would be a function of cumulative operating hours rather than operating years.

**Table 5-2 — Gas/Oil CC CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | Variable O&M (2017 $/kW-yr)* | Total O&M (2017 $/kW-yr)* | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr)* |
|---|---|---|---|---|---|---|
| CC Dataset Results – All Plants | 13.08 | 3.91 | (included in CAPEX) | 13.08 | 15.76 | 28.84 |
| < 500 MW | 15.62 | 4.31 | (included in CAPEX) | 15.62 | 17.38 | 33.00 |
| 500 MW – 1,000 MW | 9.27 | 3.42 | (included in CAPEX) | 9.27 | 13.78 | 23.05 |
| > 1,000 MW | 11.68 | 3.37 | (included in CAPEX) | 11.68 | 13.57 | 25.25 |
| Existing EMM Value** | 27.52 | 2.64 | 10.64 | 38.16 | 0.18; 7.25 (after year 30) | 38.34; 45.41 (after year 30) |

*Calculated at the gas/oil CC dataset average capacity factor of 46%. Fixed and variable O&M split is estimated.
**Source: Internal communication with EIA, February 2018.

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

# 6. GAS/OIL COMBUSTION TURBINE

## 6.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for gas/oil CT plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
    - 625 plants from FERC data and 27 plants from Sargent & Lundy internal data
    - 4,905 valid data points in FERC data, 437 valid data points in Sargent & Lundy internal data
- CAPEX
    - 579 plants from FERC data and five plants from Sargent & Lundy internal data
    - 4,949 valid data points in FERC data, 136 valid data points in Sargent & Lundy internal data

The CT data was broken down by plant MW capacity, as summarized below in Table 6-1, for the regression analysis shown in Appendix D.

**Table 6-1 — Gas/Oil Combustion Turbine Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 5,041 | 4,905 | 4,949 | 437 | 136 |
| < 100 MW | All | 2,873 | 2,873 | 2,911 | 189 | 0 |
| 100 MW – 300 MW | All | 1,341 | 1,239 | 1,248 | 177 | 102 |
| > 300 MW | All | 901 | 867 | 875 | 71 | 34 |

## 6.2 SUMMARY OF RESULTS

As with coal steam and gas/oil steam plants, CAPEX spending for gas/oil CT plants represents a series of capital projects throughout the plant life, which includes projects for "life extension." Most CAPEX spending for gas/oil CT plants is for vendor-specified major maintenance events. Other CAPEX spending, other than for emission control retrofits, is relatively minor.

Vendor-specified major maintenance spending is based on cumulative hours of operation and/or cumulative starts. Implicitly, CAPEX spending for CTs is age-related and vendor-specified, and may be expressed as an equivalent $/MWh value, which covers:

- Major maintenance costs for periodic combustion inspections, hot gas path inspections, and major overhauls account for nearly all of the CAPEX expenditures. Many plant owners choose to capitalize major maintenance expenditures. As these expenditures normally follow the equipment vendor's recommendations, they maintain plant performance and extend the plant life.
- Major one-time costs include rotor replacement, typically at about 150,000 equivalent operating hours, 7,000 equivalent starts, or within the first 30 years of plant operation. These costs are captured within the dataset. As gas turbines age, major maintenance parts often become available from third-party suppliers at a discounted price.

As with MMRAs (described in Section 4.2.1), major maintenance contracts are priced according to smoothed versions of irregular long-term expenditure patterns. Apart from adjustments for operating conditions, major maintenance (and nearly all of the CAPEX) is effectively priced as an equal annual value, expressed in constant $/MWh with annual escalation.

Table 6-2 compares the new CAPEX and O&M values derived from the gas/oil CT datasets with the values currently used in the EMM. As previously mentioned, the combined CAPEX and O&M in the datasets would be expected to correspond to the combined CAPEX and O&M in the EMM, with most of the CAPEX in the EMM represented as variable O&M. However, EMM fixed and variable O&M costs across all plant sizes are higher than values Sargent & Lundy has observed in actual CT plants. Since most CT plants operate as peaking plants with low capacity factors, the variable O&M component is likely to be based on equivalent starts rather than equivalent operating hours.

### Table 6-2 — Gas/Oil Combustion Turbine CAPEX and O&M Comparison with Existing EMM

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | Variable O&M (2017 $/kW-yr)* | Total O&M (2017 $/kW-yr)* | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr)* |
|---|---|---|---|---|---|---|
| CT Dataset Results – All Plants | 5.33 | (starts based) | (included in CAPEX) | 5.33 | 6.90 | 12.23 |
| < 100 MW | 5.96 | (starts based) | (included in CAPEX) | 5.96 | 9.00 | 14.96 |
| 100 MW – 300 MW | 6.43 | (starts based) | (included in CAPEX) | 6.43 | 6.18 | 12.61 |
| > 300 MW | 3.99 | (starts based) | (included in CAPEX) | 3.99 | 6.95 | 10.94 |
| Existing EMM Value** | 12.60 | 14.63 | 5.13 | 17.73 | 1.52 | 19.25 |

*Calculated at the gas/oil CC dataset average capacity factor of 4%.
**Source: Internal communication with EIA, February 2018.

CAPEX and O&M spending have a relatively minor effect on future non-fuel O&M spending, on average, compared with plant performance-related economic benefits not captured in this analysis, such as:

- Reduced fuel expenditures due to improved heat rates
- Reduced capacity degradation and higher capacity sales
- Reduced outage costs due to reduced replacement power expenses or higher power sales
- Increased power sales due to increased net capacity or reduced forced outages

# 7. CONVENTIONAL HYDROELECTRIC

## 7.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for conventional hydroelectric plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 348 plants in FERC data
  - 2,179 valid data points in FERC data
- CAPEX
  - 348 plants in FERC data
  - 2,180 valid data points in FERC data

The conventional hydroelectric data was broken down by plant MW capacity, as summarized below in Table 7-1, for the regression analysis shown in Appendix E.

**Table 7-1 — Conventional Hydroelectric Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 2,179 | 2,179 | 2,180 | 0 | 0 |
| < 100 MW | All | 1,272 | 1,272 | 1,272 | 0 | 0 |
| 100 MW – 500 MW | All | 924 | 924 | 925 | 0 | 0 |
| > 500 MW | All | 41 | 41 | 41 | 0 | 0 |

## 7.2 SUMMARY OF RESULTS

Sargent & Lundy's linear regression analysis of the dataset for conventional hydroelectric plants (Appendix E) supports age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). CAPEX spending for this dataset may be estimated by the regression equation:

**Annual CAPEX spending in 2017 \$/kW-year = 7.269 + (0.296 × age)**

The dataset also supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 \$/kW-year = 22.360 + (0.073 × age)**

The CAPEX and O&M values derived from the conventional hydroelectric dataset are significantly higher than the existing values used in the EMM (Table 7-2) and outside the range of values published in the AEO[12] and by the International Renewable Energy Agency (IRENA).[13] The reasons for this discrepancy are not known without having the data sample used for the EMM values. It appears that the EMM does not currently account for CAPEX or life extension expenditures for conventional hydroelectric.

**Table 7-2 — Hydroelectric CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr) |
|---|---|---|---|---|
| Conventional Hydroelectric Dataset Results – All Plants | 22.00 | - | 22.56 | 44.56 |
| Existing EMM Value* | 14.58 | 0.00 | 0.00 | 14.58 |

*Source: Internal communication with EIA, February 2018.

[12] Energy Information Administration, *Annual Energy Outlook 2018*, Cost and Performance Characteristics (Table 8.2), February 2018.
[13] International Renewable Energy Agency, *Renewable Energy Technologies: Cost Analysis Series, Hydropower*, June 2012.

# 8. PUMPED HYDROELECTRIC STORAGE

## 8.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for pumped storage plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 37 plants in FERC data
  - 226 valid data points in FERC data
- CAPEX
  - 37 plants in FERC data
  - 227 valid data points in FERC data

The pumped storage data was broken down by plant MW capacity, as summarized below in Table 8-1, for the regression analysis shown in Appendix F.

**Table 8-1 — Pumped Storage Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 226 | 226 | 227 | 0 | 0 |
| < 100 MW | All | 12 | 12 | 12 | 0 | 0 |
| 100 MW – 500 MW | All | 88 | 88 | 88 | 0 | 0 |
| > 500 MW | All | 126 | 126 | 126 | 0 | 0 |

## 8.2 SUMMARY OF RESULTS

Overall, the pumped storage dataset does not support any age-related CAPEX or O&M spending trend across the full data and on any of the subsets by plant size. The average value over all operating years is \$14.83/kW-year for CAPEX and \$23.63/kW-year for O&M (Table 8-2). The existing values used in the EMM are not available.

**Table 8-2 — Pumped Storage CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr) |
|---|---|---|---|---|
| Pumped Storage Dataset Results – All Plants | 23.63 | - | 14.83 | 38.46 |
| Existing EMM Value | N/A | N/A | N/A | N/A |

# 9. SOLAR PHOTOVOLTAIC

## 9.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for solar PV storage plants were compiled using the assessment methodology described in Section 2. The FERC data includes 105 solar PV installations ranging in capacity from 10 kW to 36 MW.

The solar PV data, summarized below in Table 9-1, was used for the regression analysis shown in Appendix G.

**Table 9-1 — Solar Photovoltaic Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 57 | 410 | 57 | 0 | 0 |

## 9.2 SUMMARY OF RESULTS

The solar PV dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size (see Appendix G). Sargent & Lundy determined that a significant portion of the data needed to be filtered out, resulting in a limited dataset of 15 sites. The average annual CAPEX (i.e., change in TCP) for these sites was approximately $26/kW-year. However, due to the limitations of the solar PV dataset, described in Appendix G, Sargent & Lundy advises that caution be taken when trying to establish any definitive solar PV capital cost trends from the FERC data.

The solar PV dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, based on a closer inspection of the data, a more appropriate predictor of O&M spending for this dataset would be a simple average across all years. This determination is based on the lack of data points for plants over 10 years old and the fact that nearly all data points for plants over 10 years old are reported as having zero O&M expenses. Additionally, many of these plants also reported zero O&M expenses for all years of operation.

Solar PV O&M activities include a variety of work scopes, including administrative work, monitoring, cleaning, preventative maintenance, and corrective maintenance. Some specific examples of O&M activities may include cleaning modules, monitoring system voltage and current, inspecting and cleaning electrical equipment, inspecting modules for damage, inspecting mounting systems, and checking invertor settings. The cost of O&M is dependent on several factors, including the number of components, the type of system (e.g., roof, tracking, ground mount, fixed, etc.), warranty coverage, and location. Environmental conditions, such as hail, sand/dust, snow, salt in air, high winds, etc., also play a significant role in O&M costs. For these reasons, a higher level of variation is expected when compared to traditional generating technologies.

An average O&M cost of $75/kW-year was calculated from the FERC data for sites under 5 MW, and $15/kW-year for sites over 5 MW. Sargent & Lundy notes that, compared to other industry metrics shown in Appendix G, the FERC data averages are similar for the sites over 5 MW but much higher for the sites under 5 MW.

If the results of the regression analysis are used, the average O&M costs are reduced to $41/kW-year for sites under 5 MW and $10/kW-year for sites over 5 MW. The regression analysis uses each year of plant data as a unique data point, which captures the years in which zero O&M costs were reported.

By comparison, the EMM uses an average O&M value of $28.47/kW-year for all solar PV plants and an average CAPEX value of zero.[14] Neither dataset captures the most recent trends in solar PV technology due to rapid changes in cost, size, and efficiency.

[14] Internal communication with EIA, February 2018.

# 10. SOLAR THERMAL

## 10.1 DATA DESCRIPTION

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

## 10.2 SUMMARY OF RESULTS

The U.S. National Renewable Energy Laboratory (NREL) published an Annual Technology Baseline (ATB) in 2017 that estimates the capital and O&M cost of a 100-MWnet solar power tower plant with 10 hours of thermal storage, based on cost models benchmarked with industry data.[15] The estimate includes future projections based on possible reductions in costs (high, mid, or low). The 2017 ATB includes a 2015 baseline. An update is expected to be made available in 2018.

[15] NREL 2017 Annual Technology Baseline (https://atb.nrel.gov/electricity/2017/index.html?t=sc)

# 11. GEOTHERMAL

## 11.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for geothermal plants were compiled using the assessment methodology described in Section 2. The FERC data includes five geothermal installations ranging in capacity from 23 MW to 1,224 MW.

The geothermal data summarized in Table 11-1 was used for the regression analysis shown in Appendix I.

**Table 11-1 — Geothermal Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 36 | 38 | 36 | 0 | 0 |

## 11.2 SUMMARY OF RESULTS

Overall, the geothermal dataset does not support any age-related CAPEX spending trend across the full data and on any of the subsets by plant size. Instead, we recommend a simple average be used across the full age range. Sargent & Lundy recommends using the indicated $/kW-year average in Table 11-2 for O&M and CAPEX spending. As shown in the table, it appears the EMM does not currently account for CAPEX or life extension expenditures for geothermal plants.

**Table 11-2 — Geothermal CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) | Total O&M and CAPEX (2017 $/kW-yr) |
|---|---|---|---|---|
| Geothermal Dataset Results – All Plants | 157.10 | - | 40.94 | 198.04 |
| Existing EMM Value* | 91.66 | 0.00 | 0.00 | 91.66 |

*Source: Internal communication with EIA, February 2018.

# 12. WIND

## 12.1 DATA DESCRIPTION

Annual O&M and CAPEX expenditures for wind plants were compiled using the assessment methodology described in Section 2. The valid data points derived from this process were distributed as follows:

- O&M Expenditures
  - 73 plants in FERC and 24 from Sargent & Lundy proprietary plants with valid data
  - 310 valid data points in FERC, 270 valid data points in Sargent & Lundy proprietary plants
- CAPEX
  - 97 plants in FERC with valid data
  - 310 valid data points in FERC

Sargent & Lundy's dataset includes both actual historical cost reporting from operating wind projects as well as forecasted budgetary cost projections prepared by project developers and operators with large project portfolios.

Operating costs are assumed to include all expenses related to the maintenance of the wind project, such as planned and unplanned maintenance of the wind turbines and electrical balance of plant (including labor, parts, materials, and consumables) as well as operating expenses (such as facility monitoring and management fees, utilities, land lease and royalty payments, professional service fees, taxes, and insurance).

The wind data was broken down by plant MW capacity, as summarized below in Table 12-1, for the regression analysis shown in Appendix J.

**Table 12-1 — Wind Cost Data Distribution**

| Plant Size | Average Net Capacity Factor (%) | Valid Data Points | FERC Data | | Sargent & Lundy Internal Data | |
|---|---|---|---|---|---|---|
| | | | O&M Data Points | CAPEX Data Points | O&M Data Points | CAPEX Data Points |
| All MW | All | 310 | 310 | 310 | 270 | 0 |
| < 100 MW | All | 174 | 174 | 174 | 165 | 0 |
| 100 MW – 200 MW | All | 91 | 91 | 91 | 56 | 0 |
| > 200 MW | All | 51 | 51 | 51 | 73 | 0 |

## 12.2 SUMMARY OF RESULTS

The dataset supports age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equations shown in Table 12-2. Age was not a significant predictor of CAPEX spending, although CAPEX was found to vary significantly as a function of capacity (kW). That is, CAPEX was lower on a $/kW-year basis for larger plant sizes due to economies of scale.

The CAPEX and O&M values derived from the wind dataset are significantly higher than the existing values used in the EMM. The reasons for this discrepancy are not known without having the data sample used for the EMM values. Neither data sample is stratified by wind technology or turbine size. Neither dataset captures the most recent trends in wind turbine technology due to rapid changes in cost, size, and efficiency.

**Table 12-2 — Wind CAPEX and O&M Comparison with Existing EMM**

| | Fixed O&M (2017 $/kW-yr) | Variable O&M (2017 $/MWh) | CAPEX (2017 $/kW-yr) |
|---|---|---|---|
| Wind Dataset Results – All Plants | 31.66 + (1.22 × age) | 0.00 | 18.29 |
| < 100 MW | 39.08 + (1.12 × age) | 0.00 | 20.48 |
| 100 MW – 200 MW | 23.80 + (1.17 × age) | 0.00 | 16.93 |
| > 200 MW | 26.78 + (0.92 × age) | 0.00 | 13.48 |
| Existing EMM Value* | 29.31 | 0.00 | 0.00 |

*Source: Internal communication with EIA, February 2018.

# Appendix A. Regression Analysis – Coal Steam

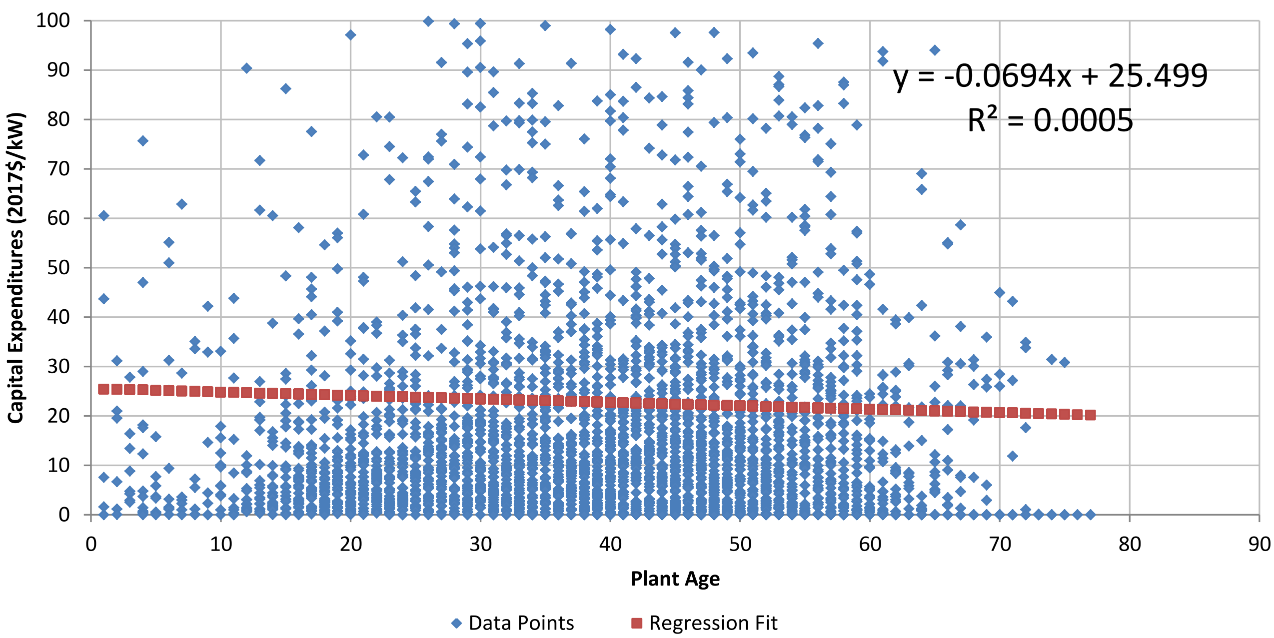
## CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.19, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). However, age and FGD are significant variables when an FGD variable is added to the regression equation (see below).

### Table A-1 — Regression Statistics – Coal CAPEX for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 3,724 | | |
| **Simple Average ($/kW)** | 22.782 | | |
| **Intercept** | 25.499 | 11.4859 | 4.95E-30 |
| **Slope** | -0.069 | -1.3054 | 1.92E-01 |
| **$R^2$** | 0.00046 | | |

### Figure A-1 — Coal Steam Dataset – CAPEX for All MW Plant Sizes




Note: Age coefficient in above regression equation is not statistically significant.

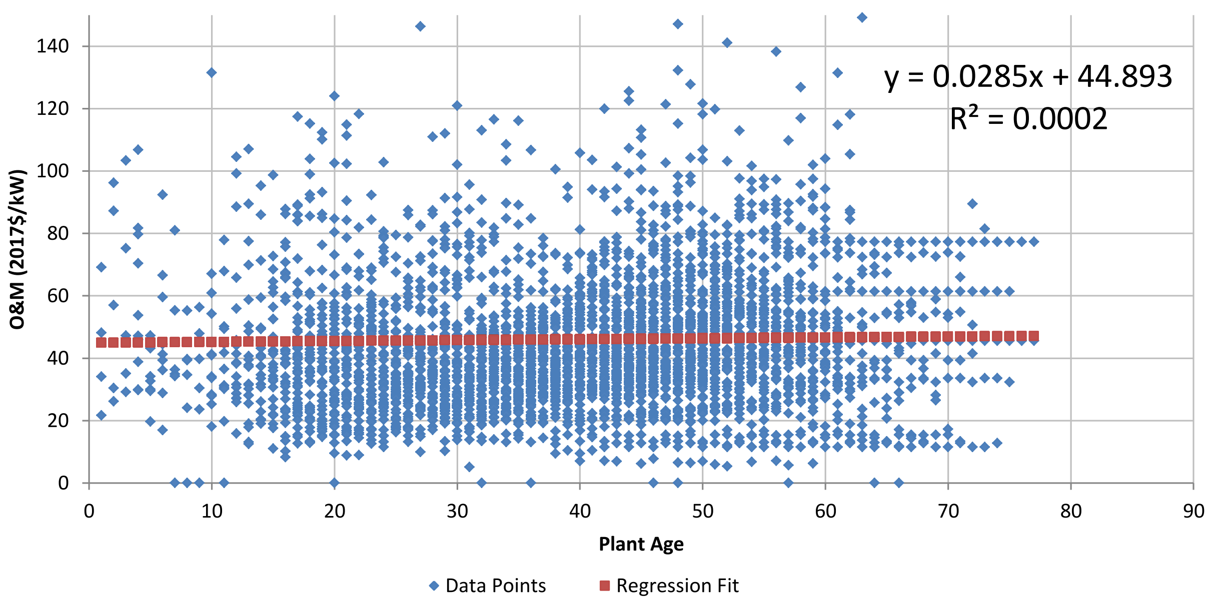
## OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for coal steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.38, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

### Table A-2 — Regression Statistics – Coal O&M for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 3,753 | | |
| **Simple Average ($/kW)** | 46.013 | | |
| **Intercept** | 44.893 | 33.2097 | 3.08E-212 |
| **Slope** | 0.028 | 0.8843 | 3.77E-01 |
| **$R^2$** | 0.00021 | | |

### Figure A-2 — Coal Steam Dataset – O&M for All MW Plant Sizes




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 53.90 | 40.06 | 48.77 | **46.01** | 440 | 1,448 | 1,865 | **3,753** |
| Net Total Capex - 2017 $/kW | 17.92 | 26.20 | 21.25 | **22.78** | 441 | 1,450 | 1,833 | **3,724** |
| Net Total O&M and Capex - 2017 $/kW | 71.86 | 66.25 | 69.82 | **68.67** | 440 | 1,448 | 1,825 | **3,713** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

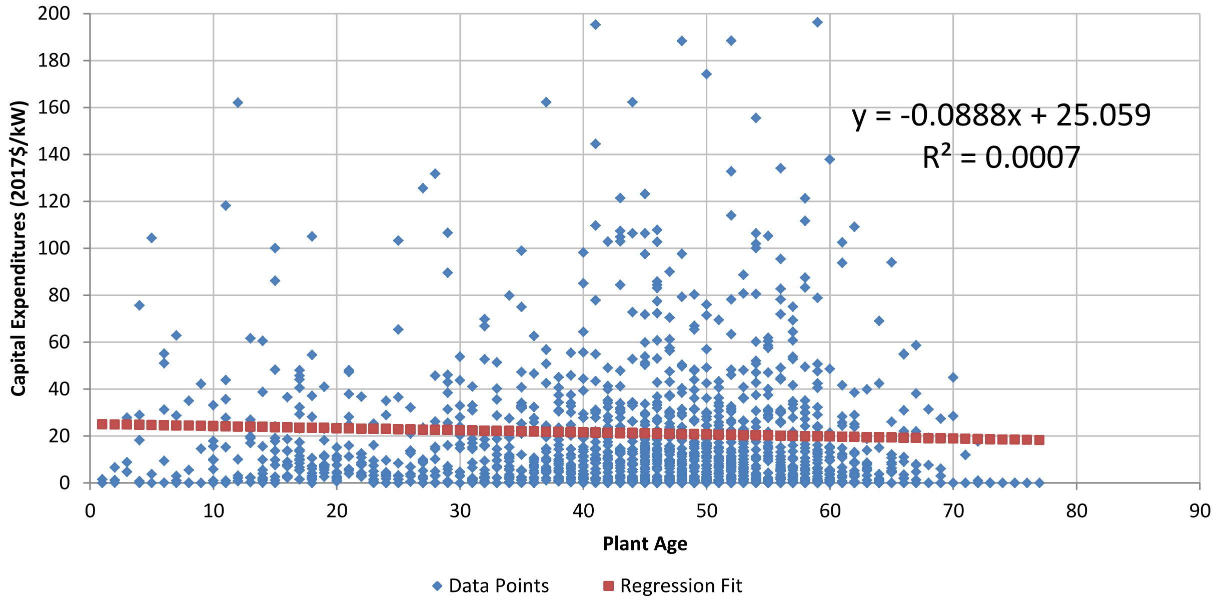
## CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the linear regression analysis of CAPEX spending for coal steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.28, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

**Table A-3 — Regression Statistics – Coal CAPEX < 500 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,602 | | |
| **Simple Average ($/kW)** | 21.187 | | |
| **Intercept** | 25.059 | 6.5593 | 7.28E-11 |
| **Slope** | -0.089 | -1.0685 | 2.85E-01 |
| **$R^2$** | 0.00071 | | |

**Figure A-3 — Coal Steam Dataset – CAPEX for Less than 500-MW Plant Size**




Note: Age coefficient in above regression equation is not statistically significant.

## OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

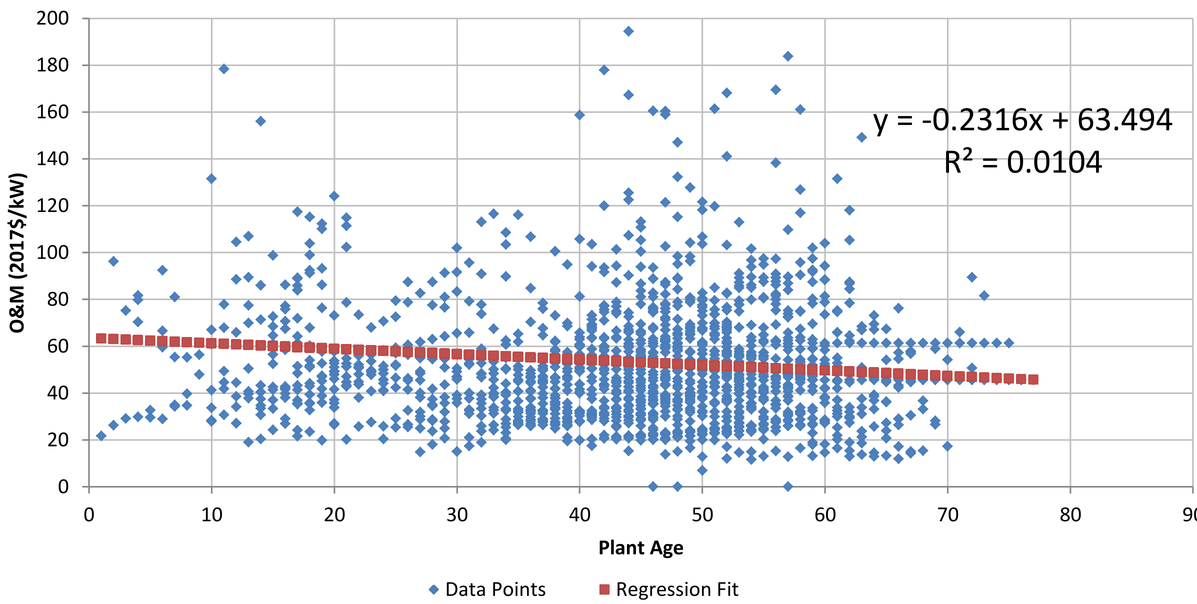
The results of the regression analysis of O&M spending for coal steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the following regression equation:

**Annual spending in 2017 \$/kW-year = 63.494 + (-0.232 × age)**

**Table A-4 — Regression Statistics – Coal O&M < 500 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,592 | | |
| **Simple Average (\$/kW)** | 53.406 | | |
| **Intercept** | 63.494 | 24.4603 | 2.03E-112 |
| **Slope** | -0.232 | -4.0977 | 4.38E-05 |
| **$R^2$** | 0.01045 | | |

**Figure A-4 — Coal Steam Dataset – O&M for Less than 500-MW Plant Size**




The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **< 500 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 68.13 | 47.13 | 53.16 | **53.41** | 169 | 355 | 1,068 | **1,592** |
| Net Total Capex - 2017 $/kW | 21.01 | 22.83 | 20.67 | **21.19** | 169 | 357 | 1,076 | **1,602** |
| Net Total O&M and Capex - 2017 $/kW | 89.14 | 69.91 | 73.93 | **74.65** | 169 | 355 | 1,068 | **1,592** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

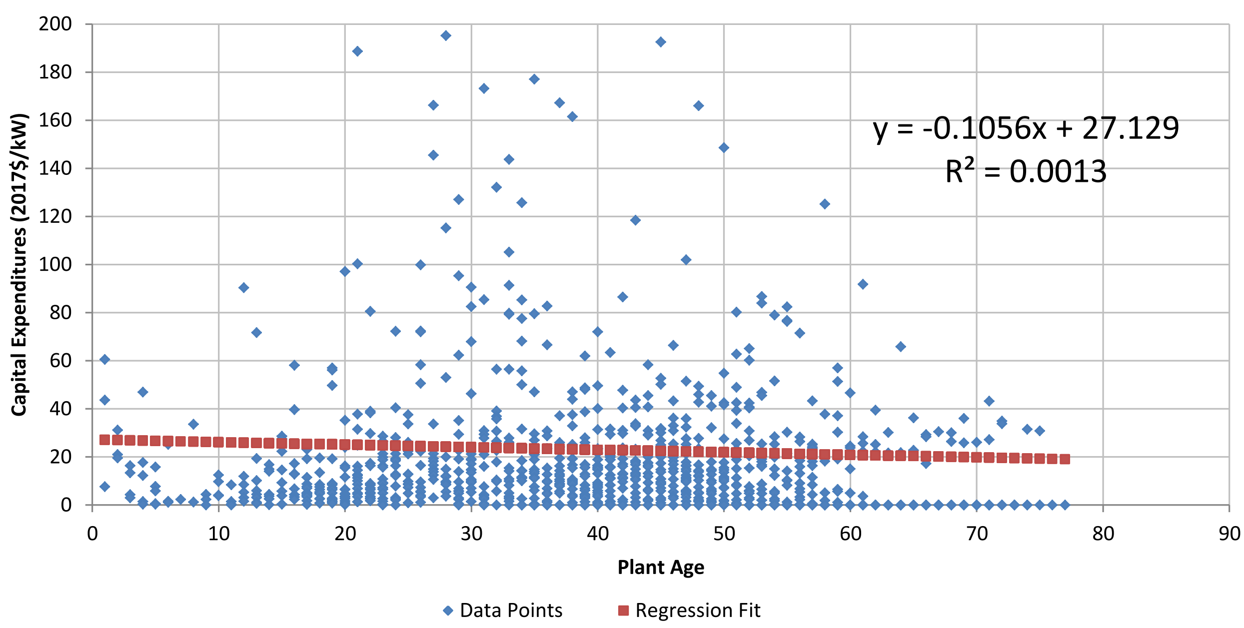
## CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the linear regression analysis of CAPEX spending for coal steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.26, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

### Table A-5 — Regression Statistics – Coal CAPEX 500 MW to 1,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 986 | | |
| **Simple Average ($/kW)** | 23.021 | | |
| **Intercept** | 27.129 | 6.8576 | 1.24E-11 |
| **Slope** | -0.106 | -1.1195 | 2.63E-01 |
| **$R^2$** | 0.00127 | | |

### Figure A-5 — Coal Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size




Note: Age coefficient in above regression equation is not statistically significant.

## OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

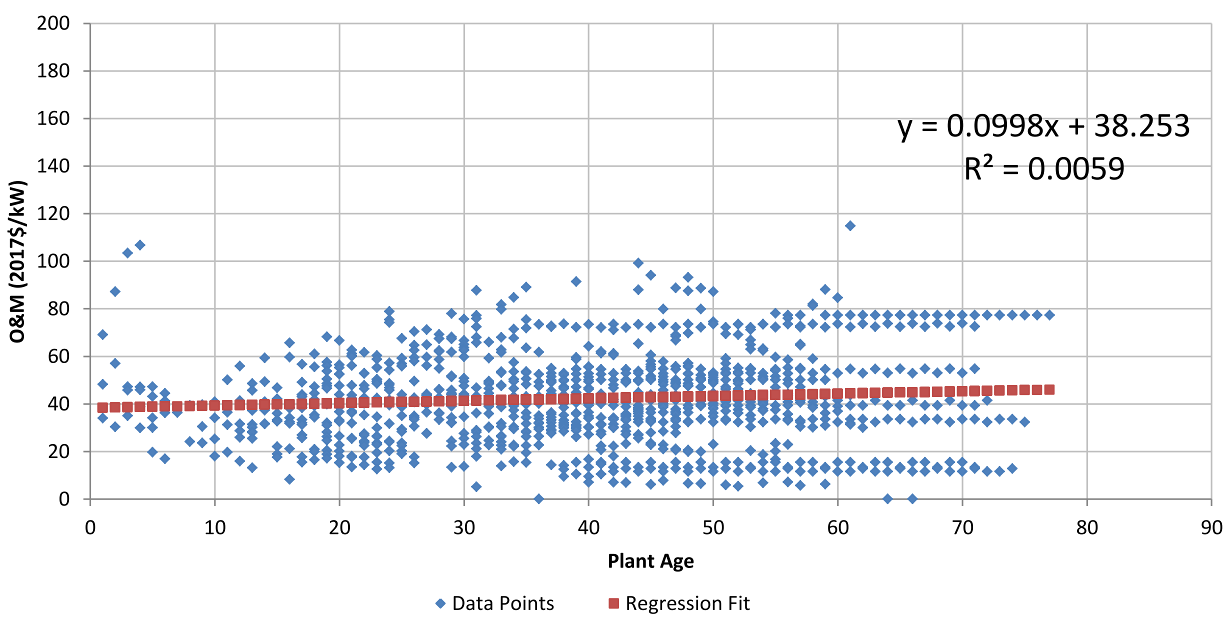
The results of the linear regression analysis of O&M spending for coal steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual spending in 2017 $/kW-year = 38.253 + (0.100 × age)**

### Table A-6 — Regression Statistics – Coal O&M 500 MW to 1,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,026 | | |
| **Simple Average ($/kW)** | 42.223 | | |
| **Intercept** | 38.253 | 22.0915 | 9.54E-89 |
| **Slope** | 0.100 | 2.4710 | 1.36E-02 |
| **$R^2$** | 0.00593 | | |

### Figure A-6 — Coal Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size




Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **500 MW - 1000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 38.15 | 42.09 | 43.40 | **42.22** | 138 | 369 | 519 | **1,026** |
| Net Total Capex - 2017 $/kW | 12.27 | 32.63 | 18.71 | **23.02** | 138 | 369 | 479 | **986** |
| Net Total O&M and Capex - 2017 $/kW | 50.41 | 74.72 | 60.65 | **64.49** | 138 | 369 | 479 | **986** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

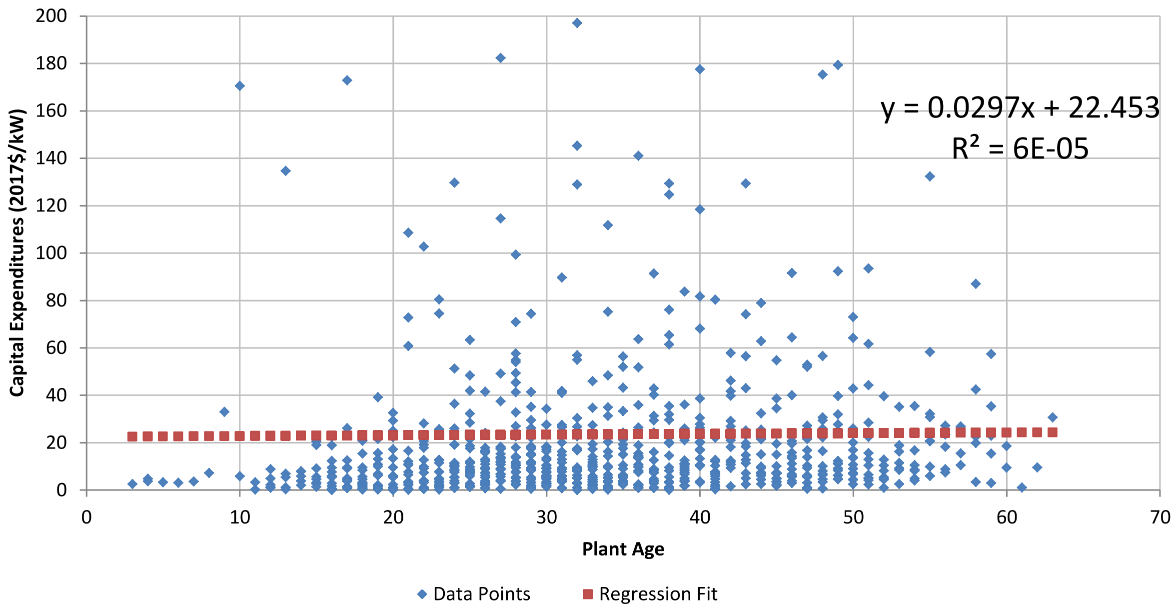
## CAPITAL EXPENDITURES – BETWEEN 1,000 MW AND 2,000 MW

The results of the regression analysis of CAPEX spending for coal steam plants between 1,000 MW and 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.83, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

**Table A-7 — Regression Statistics – Coal CAPEX 1,000 MW to 2,000 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 814 | | |
| **Simple Average ($/kW)** | 23.448 | | |
| **Intercept** | 22.453 | 4.6325 | 4.21E-06 |
| **Slope** | 0.030 | 0.2174 | 8.28E-01 |
| **$R^2$** | 0.00006 | | |

**Figure A-7 — Coal Steam Dataset – CAPEX for 1,000-MW to 2,000-MW Plant Size**




Note: Age coefficient in above regression equation is not statistically significant.

## OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 1,000 MW AND 2,000 MW

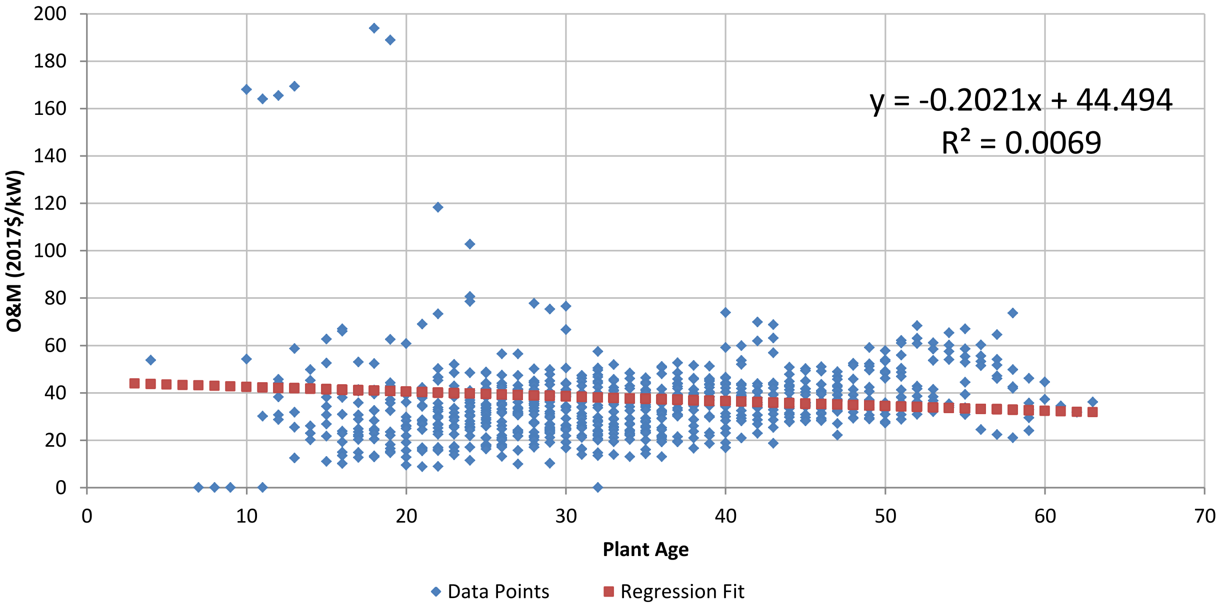
The results of the regression analysis of O&M spending for coal steam plants between 1,000 MW and 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual spending in 2017 \$/kW-year = 44.494 + (-0.202 × age)**

**Table A-8 — Regression Statistics – Coal O&M 1,000 MW to 2,000 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 813 | | |
| **Simple Average (\$/kW)** | 37.722 | | |
| **Intercept** | 44.494 | 14.7620 | 7.42E-44 |
| **Slope** | -0.202 | -2.3785 | 1.76E-02 |
| **$R^2$** | 0.00693 | | |

**Figure A-8 — Coal Steam Dataset – O&M for 1,000-MW to 2,000-MW Plant Size**




The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **1000 MW - 2000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 53.51 | 32.80 | 40.62 | **37.72** | 107 | 478 | 228 | **813** |
| Net Total Capex - 2017 $/kW | 22.56 | 23.31 | 24.16 | **23.45** | 108 | 478 | 228 | **814** |
| Net Total O&M and Capex - 2017 $/kW | 76.28 | 56.11 | 64.78 | **61.20** | 107 | 478 | 228 | **813** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

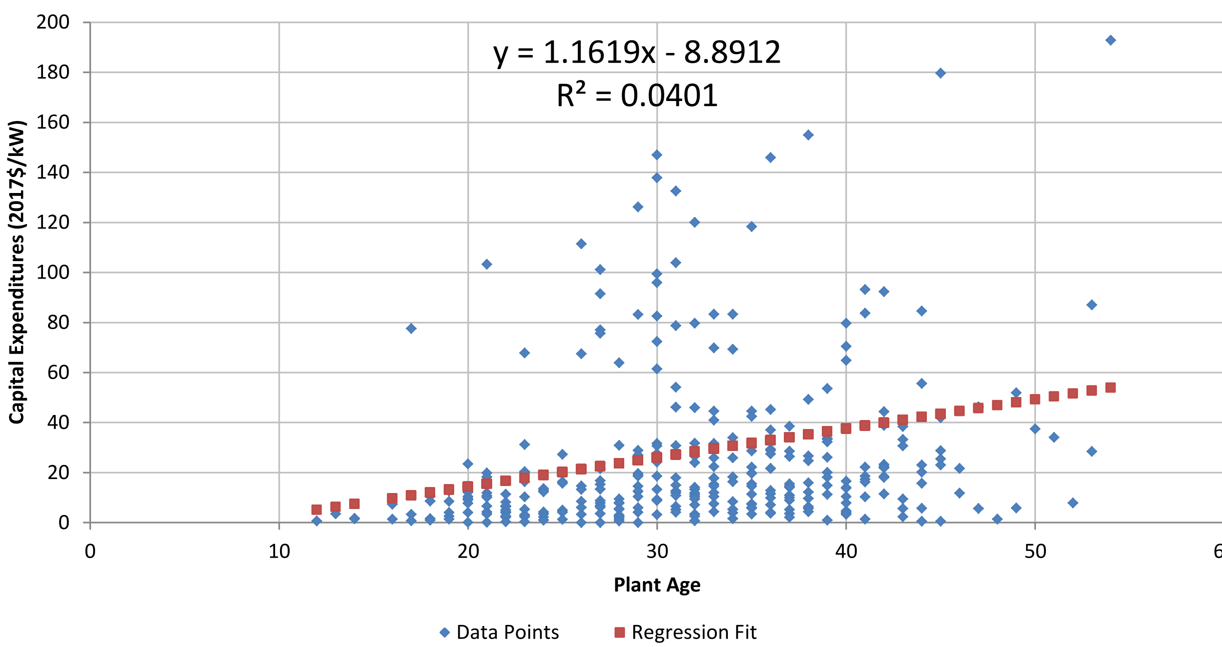
## CAPITAL EXPENDITURES – GREATER THAN 2,000 MW

The results of the regression analysis of CAPEX spending for coal steam plants greater than 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX spending. However, the linear regression analysis shows the intercept value (i.e., the CAPEX cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited amount of data causes the regression analysis to be distorted and unrealistic.

### Table A-9 — Regression Statistics – Coal CAPEX > 2,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 322 | | |
| **Simple Average ($/kW)** | 28.303 | | |
| **Intercept** | -8.891 | -0.8468 | 3.98E-01 |
| **Slope** | 1.162 | 3.6556 | 3.00E-04 |
| **$R^2$** | 0.04009 | | |

### Figure A-9 — Coal Steam Dataset – CAPEX for Greater than 2,000-MW Plant Size



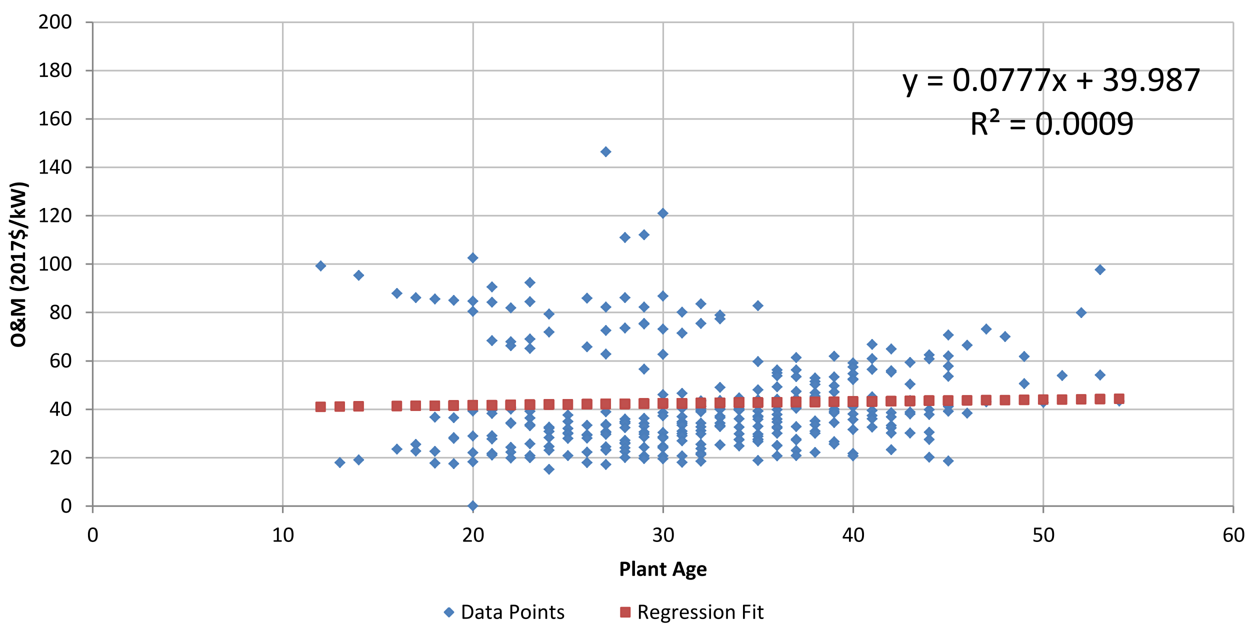
## OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 2,000 MW

The results of the regression analysis of O&M spending for coal steam plants greater than 2,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.59, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

### Table A-10 — Regression Statistics – Coal O&M > 2,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 322 | | |
| **Simple Average ($/kW)** | 42.474 | | |
| **Intercept** | 39.987 | 8.3303 | 2.39E-15 |
| **Slope** | 0.078 | 0.5348 | 5.93E-01 |
| **$R^2$** | 0.00089 | | |

### Figure A-10 — Coal Steam Dataset – O&M for Greater than 2,000-MW Plant Size




Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **> 2000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 46.55 | 40.91 | 48.04 | **42.47** | 26 | 246 | 50 | **322** |
| Net Total Capex - 2017 $/kW | 8.65 | 27.06 | 44.64 | **28.30** | 26 | 246 | 50 | **322** |
| Net Total O&M and Capex - 2017 $/kW | 55.20 | 67.97 | 92.67 | **70.78** | 26 | 246 | 50 | **322** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

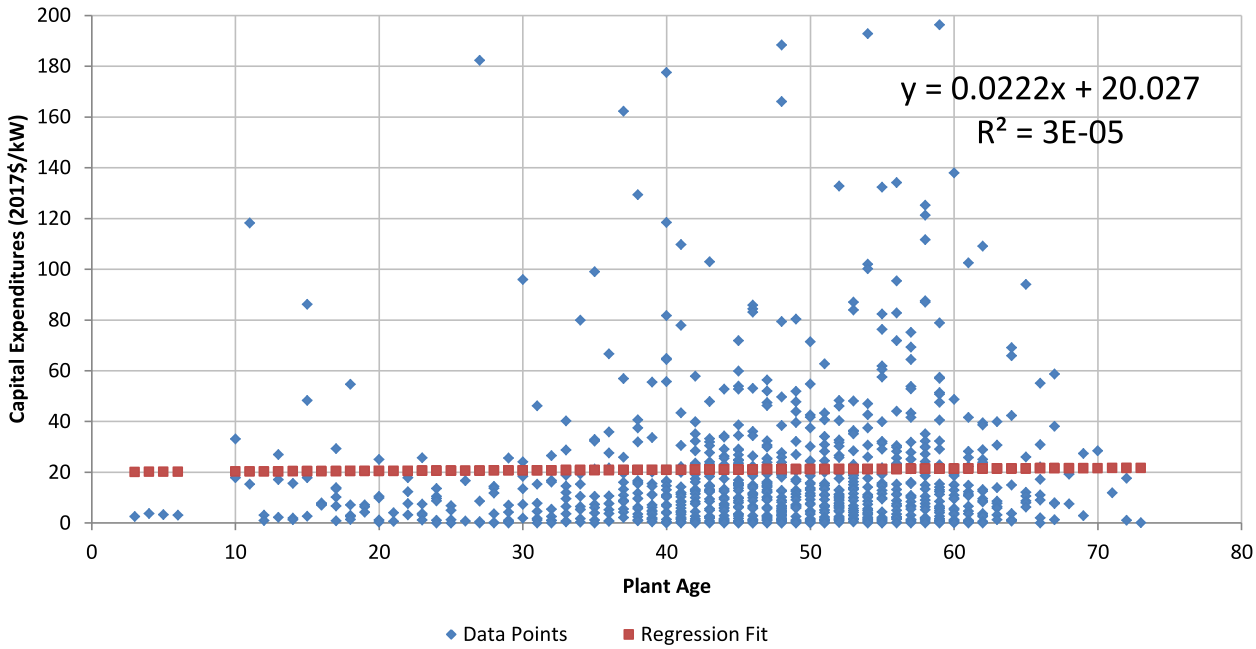
## CAPITAL EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes and with capacity factors less than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.87, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table A-11 — Regression Statistics – Coal CAPEX for Capacity Factor < 50%**

| | | ***t statistic*** | ***p-value*** |
|---|---|---|---|
| **Observations** | 972 | | |
| **Simple Average ($/kW)** | 21.063 | | |
| **Intercept** | 20.027 | 3.1188 | 1.87E-03 |
| **Slope** | 0.022 | 0.1663 | 8.68E-01 |
| **$R^2$** | 0.00003 | | |

**Figure A-11 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor < 50%**




Note: Age coefficient in above regression equation is not statistically significant.

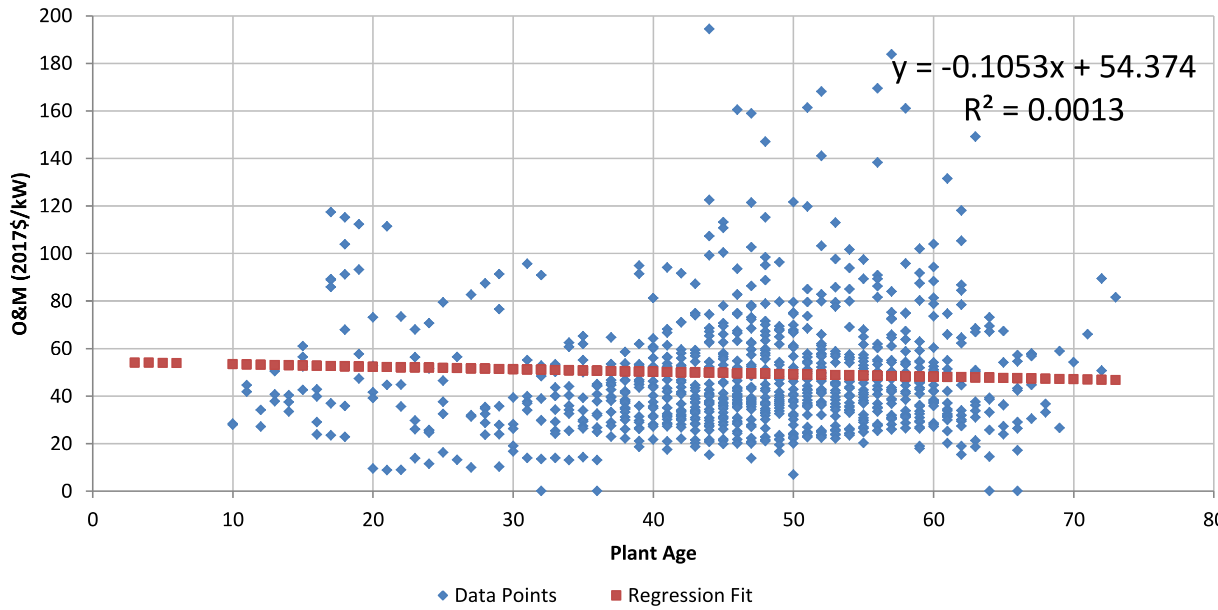
## OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of O&M spending for coal steam plants of all MW sizes and with capacity factors less than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.26, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

**Table A-12 — Regression Statistics – Coal O&M for Capacity Factor < 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 965 | | |
| **Simple Average ($/kW)** | 49.454 | | |
| **Intercept** | 54.374 | 12.0380 | 3.43E-31 |
| **Slope** | -0.105 | -1.1234 | 2.62E-01 |
| **$R^2$** | 0.00131 | | |

**Figure A-12 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor < 50%**




Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, Capacity Factors 0 - 50%** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 76.43 | 40.01 | 50.07 | **49.45** | 45 | 177 | 743 | **965** |
| Net Total Capex - 2017 $/kW | 19.62 | 23.74 | 20.51 | **21.06** | 45 | 179 | 748 | **972** |
| Net Total O&M and Capex - 2017 $/kW | 96.04 | 63.66 | 70.63 | **70.54** | 45 | 177 | 743 | **965** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

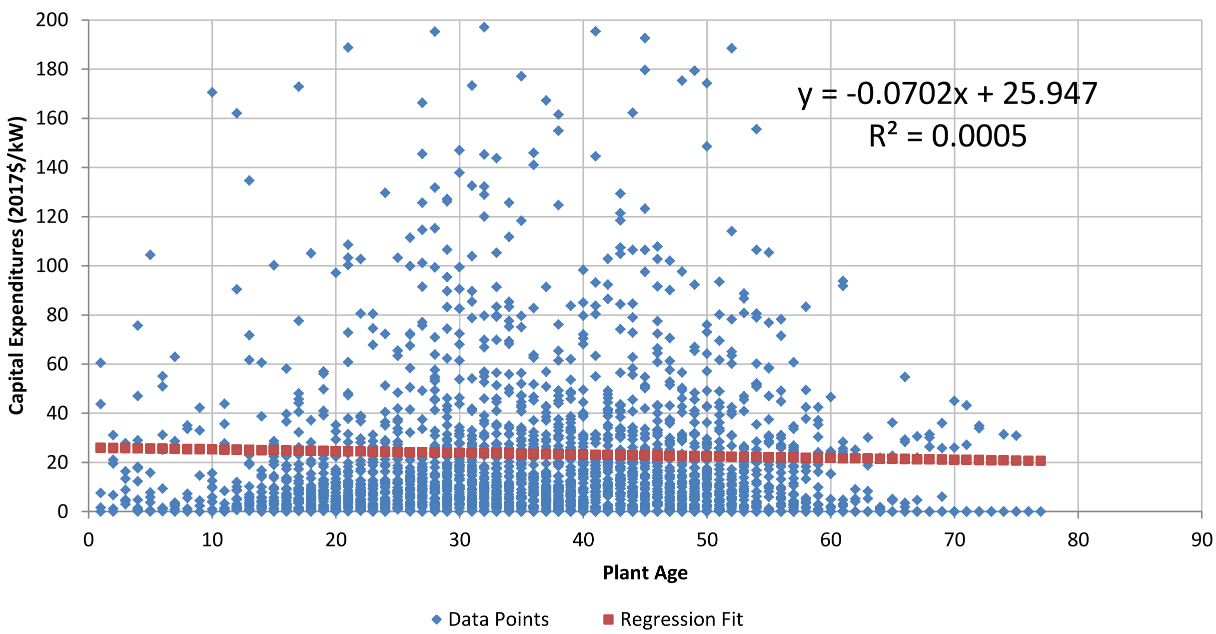
## CAPITAL EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes and with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.25, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table A-13 — Regression Statistics – Coal CAPEX for Capacity Factor > 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 2752 | | |
| **Simple Average ($/kW)** | 23.389 | | |
| **Intercept** | 25.947 | 10.7905 | 1.29E-26 |
| **Slope** | -0.070 | -1.1446 | 2.52E-01 |
| **$R^2$** | 0.00048 | | |

**Figure A-13 — Coal Steam Dataset – CAPEX for All Plants with Avg. Net Capacity Factor > 50%**




Note: Age coefficient in above regression equation is not statistically significant.

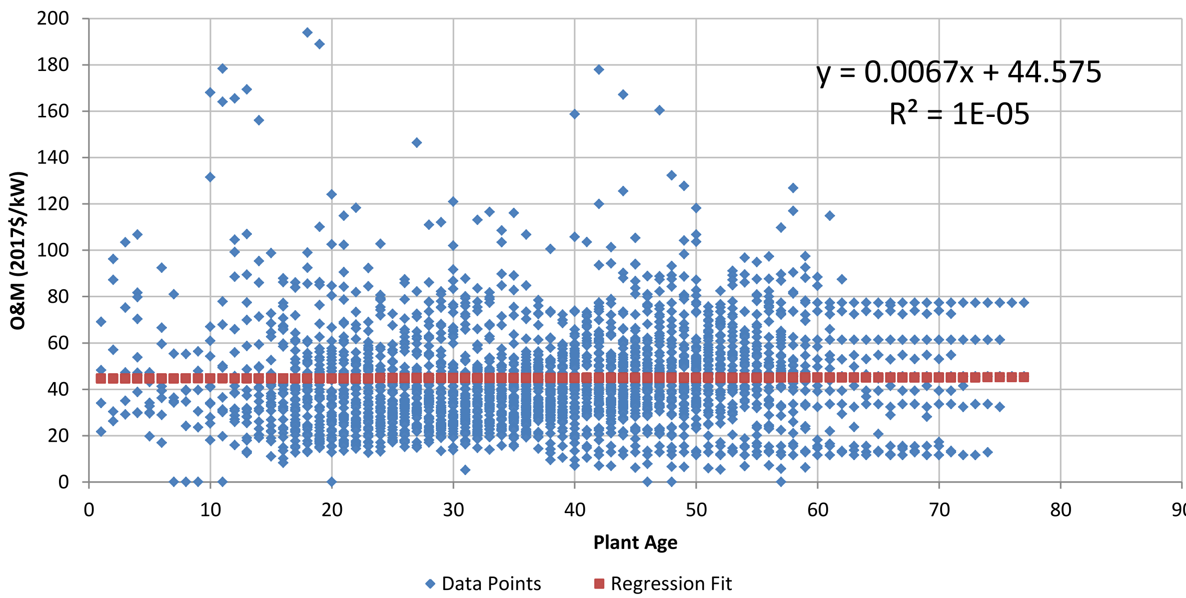
## OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of O&M spending for coal steam plants of all MW sizes and with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.85, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

**Table A-14 — Regression Statistics – Coal O&M for Capacity Factor > 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 2788 | | |
| **Simple Average ($/kW)** | 44.822 | | |
| **Intercept** | 44.575 | 32.6995 | 8.78E-199 |
| **Slope** | 0.007 | 0.1954 | 8.45E-01 |
| **$R^2$** | 0.00001 | | |

**Figure A-14 — Coal Steam Dataset – O&M for All Plants with Avg. Net Capacity Factor > 50%**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| ` | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, Capacity Factors 50% - 100%** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 51.33 | 40.07 | 47.92 | **44.82** | 395 | 1,271 | 1,122 | **2,788** |
| Net Total Capex - 2017 $/kW | 17.73 | 26.55 | 21.75 | **23.39** | 396 | 1,271 | 1,085 | **2,752** |
| Net Total O&M and Capex - 2017 $/kW | 69.11 | 66.62 | 69.25 | **68.01** | 395 | 1,271 | 1,082 | **2,748** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing coal steam plants are described in Section 3.

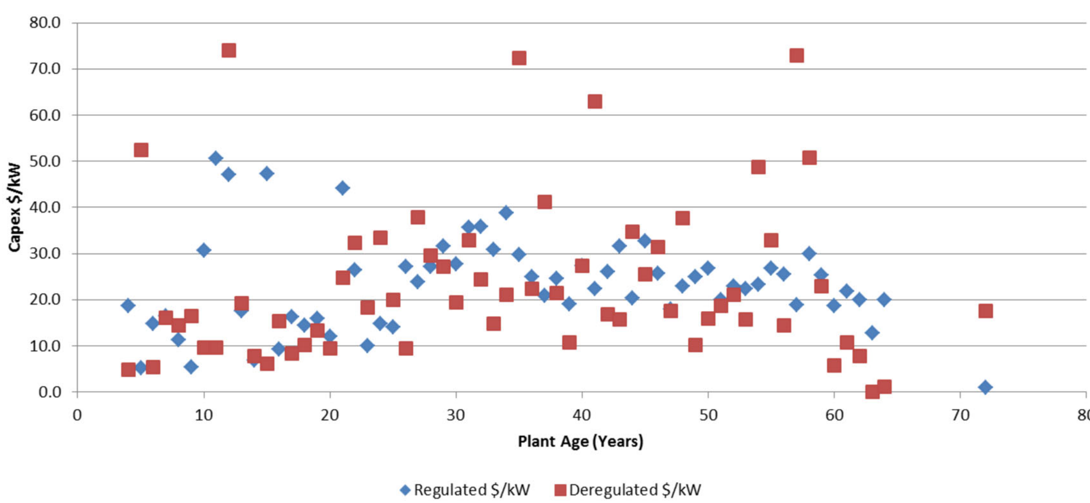
## CAPITAL EXPENDITURES – REGULATED VS. DEREGULATED

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) in regulated versus deregulated locations are summarized in the table below. Since the p-value for the age ("slope") and regulation/deregulation coefficients are much greater than 0.05, age and regulatory status are not statistically significant predictors of CAPEX spending.

**Table A-15 — Regression Statistics – Coal CAPEX for Regulated/Deregulated**

| | Coefficients | Standard Error | t Stat | P-Value |
|---|---|---|---|---|
| Intercept | 23.22826383 | 2.9645403 | 7.835367875 | 6.36821E-15 |
| Age | 0.097334249 | 0.064355791 | 1.512439626 | 0.130523796 |
| Reg./Dereg. (1/0) | -2.479225741 | 2.148990587 | -1.153669893 | 0.248724297 |

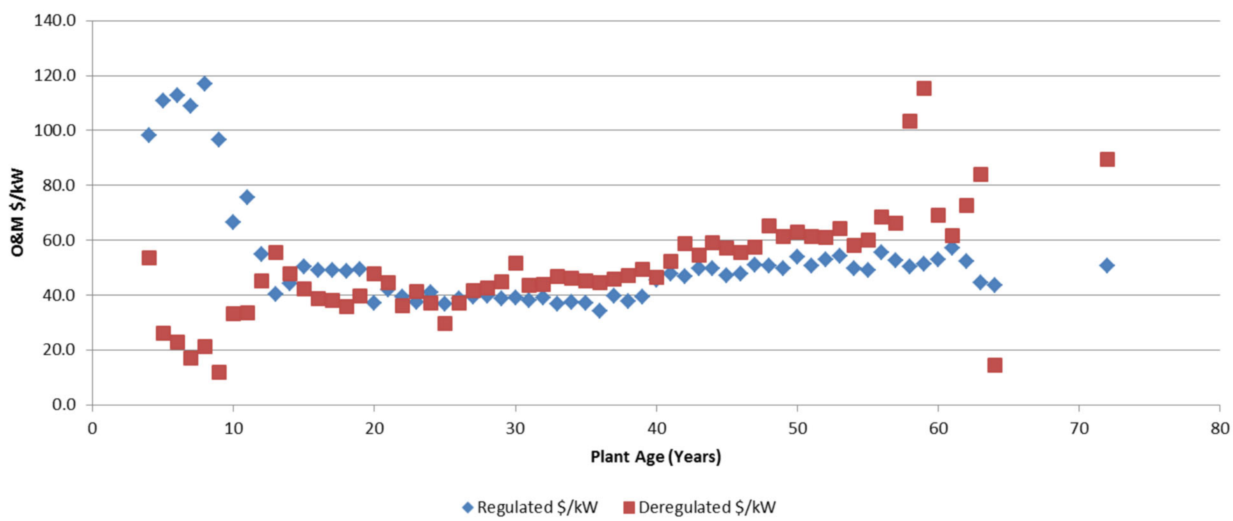
**Figure A-15 — Coal Steam Dataset – CAPEX for Regulated/Deregulated**



## OPERATIONS & MAINTENANCE EXPENDITURES – REGULATED VS. DEREGULATED

The regression analysis of O&M expenditures indicates that the p-value for the age ("slope") and regulated/deregulated coefficients are much less than 0.05 (i.e., statistically significant). However, the outliers before year 20 may tend to distort the regression analysis. After year 20, a visual inspection of the data points indicates higher O&M spending in deregulated states compared with regulated states (Figure A-16). This is the opposite of what would be expected, whereby plant owners in a deregulated environment would have a greater incentive to reduce O&M costs that cannot be passed through to ratepayers. The higher O&M spending is likely a result of other factors, such as higher average labor costs in deregulated states, which tend to have a higher percentage of union labor compared with regulated states. Therefore, the net effect of regulatory status on average O&M spending is not apparent at this level of detail.

**Figure A-16 — Coal Steam Dataset – O&M for Regulated vs. Deregulated**




## CAPITAL EXPENDITURES – FGD VS. NO FGD

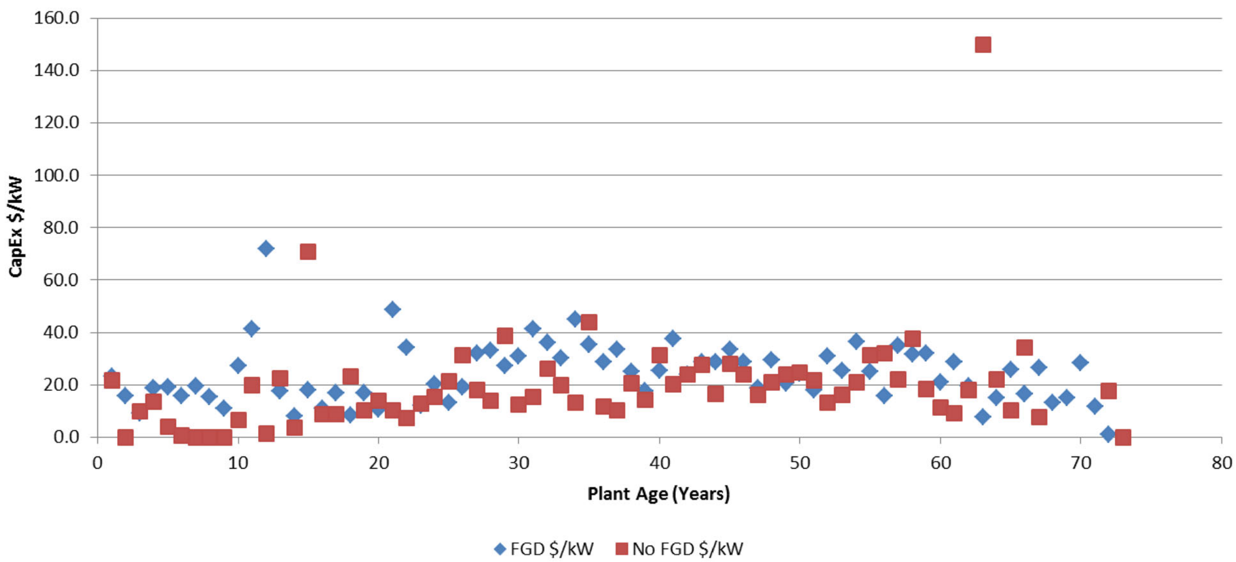
The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) with and without FGD are summarized in the table below. The p-value for the age ("slope") coefficient is slightly greater than 0.05 (nearly statistically significant) while the p-value for the FGD/no-FGD coefficient is much less than 0.05 (statistically significant). A visual inspection of the difference between the FGD and no-FGD data points in Figure A-17 shows a similarity in CAPEX spending amounts across all ages. Therefore, average CAPEX spending may be represented by the following regression equation:

| |
|---|
| **Annual CAPEX spending in 2017 \$/kW-year = 16.53 + (0.126 × age) + (5.68 × FGD)**<br>**Where FGD = 1 if plant has FGD; zero otherwise** |

**Table A-16 — Regression Statistics – Coal CAPEX for FGD/No FGD**

| | Coefficients | Standard Error | t Stat | P-Value |
|---|---|---|---|---|
| Intercept | 16.52586075 | 3.06139723 | 5.39814323 | 7.2399E-08 |
| Age | 0.126266024 | 0.065143952 | 1.93826166 | 0.05268181 |
| FGD/No FGD (1/0) | 5.6788887 | 1.913609818 | 2.96763146 | 0.00302395 |

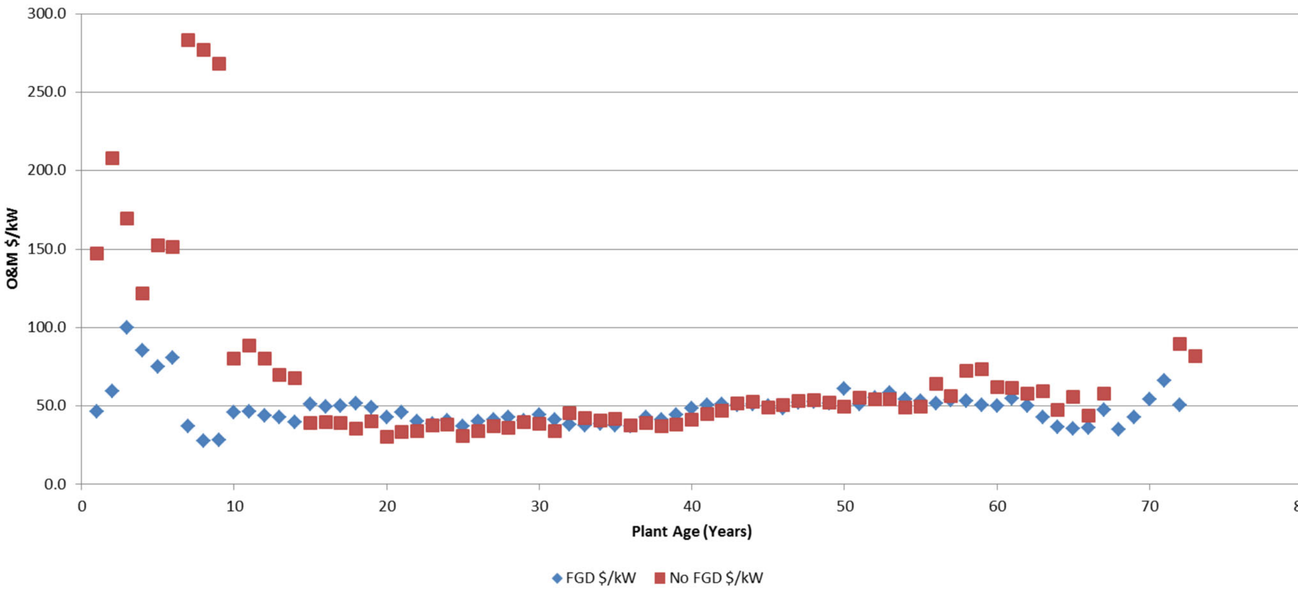
**Figure A-17 — Coal Steam Dataset – CAPEX for FGD/No FGD**




## OPERATIONS & MAINTENANCE EXPENDITURES – FGD VS. NO FGD

The regression analysis of O&M expenditures indicates that the p-value for the age ("slope") and FGD/no-FGD coefficients are much less than 0.05 (i.e., statistically significant). However, outliers before year 15 may tend to distort the regression analysis. A visual inspection of the difference between the FGD and no-FGD data points in Figure A-18 shows a similarity in O&M spending amounts across all ages after year 15. The differences in annual coal plant spending due to having FGD is more significant in the CAPEX accounts, as shown in the previous subsection, rather than the O&M accounts.

**Figure A-18 — Coal Steam Dataset – O&M for FGD vs. No FGD**



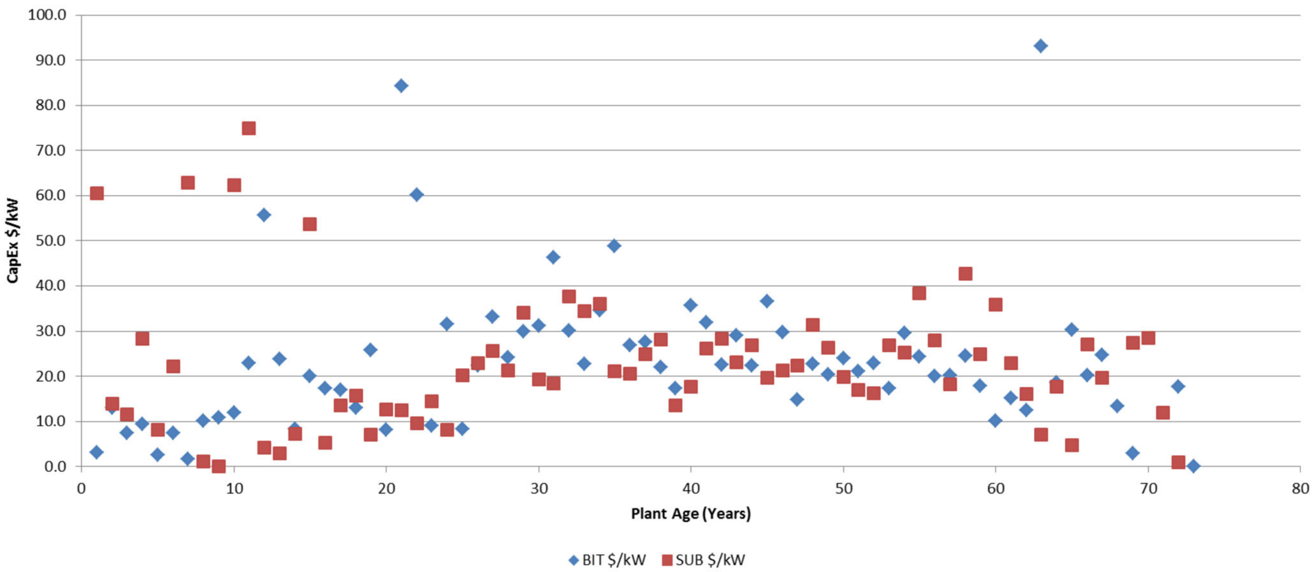

## CAPITAL EXPENDITURES – BITUMINOUS VS. SUBBITUMINOUS

The results of the regression analysis of CAPEX spending for coal steam plants of all MW sizes (full dataset) in bituminous versus subbituminous coal types are summarized in the table below. The p-value for the age ("slope") coefficient is much greater than 0.05 (not statistically significant), while the p-value for the bituminous/subbituminous coefficient is much less than 0.05 (statistically significant). However, the outliers before year 20 may tend to distort the regression analysis. Further, a visual inspection of the difference between the bituminous and subbituminous data points in Figure A-19 shows a similarity in CAPEX spending amounts across all ages. Therefore, average CAPEX spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

**Table A-17 — Regression Statistics – Coal CAPEX for Bituminous/Subbituminous**

| | Coefficients | Standard Error | t Stat | P-Value |
|---|---|---|---|---|
| Intercept | 15.39252046 | 2.257695952 | 6.817800442 | 1.08205E-11 |
| Age | -0.00350504 | 0.054578287 | -0.064220408 | 0.948798346 |
| Bit./Sub. (1/0) | 10.93481186 | 1.525466511 | 7.168175624 | 9.20398E-13 |

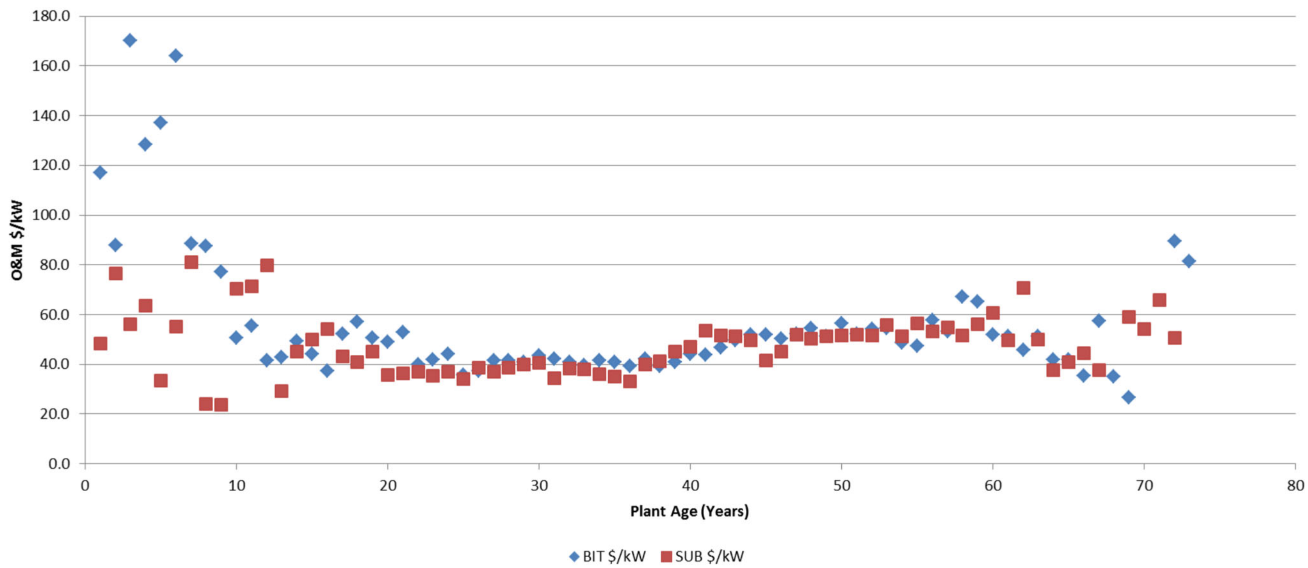
**Figure A-19 — Coal Steam Dataset – CAPEX for Bituminous/Subbituminous**




## OPERATIONS & MAINTENANCE EXPENDITURES – BITUMINOUS VS. SUBBITUMINOUS

The regression analysis of O&M expenditures indicates that the p-value for the age ("slope") and bituminous/subbituminous coefficients are much less than 0.05 (statistically significant). However, as with CAPEX spending, the outliers before year 20 may tend to distort the regression analysis. Further, a visual inspection of the difference between the bituminous and subbituminous data points in Figure A-20 shows a similarity in O&M spending amounts across all ages. Therefore, average O&M spending is not likely affected by coal type at a high-level designation (i.e., bituminous/subbituminous) without more detailed coal specifications.

**Figure A-20 — Coal Steam Dataset – O&M for Bituminous vs. Subbituminous**




## EFFECT OF PLANT CAPACITY FACTOR

CAPEX and O&M spending for the coal steam plants increased significantly with age when expressed on a $/MWh basis. This was primarily a result of significant declines in plant capacity factors over time. Figure A-21 and Figure A-22 indicate real annual increases in CAPEX and O&M spending for the coal steam plants in constant 2017 $/MWh versus plant age, with linear regression results as follows:

- Annual CAPEX in 2017 $/MWh = 3.27 + (0.0426 × age)
- Annual O&M in 2017 $/MWh = 5.44 + (0.133 × age)

**Figure A-21 — CAPEX vs. Age for All MW Coal Plants (2017 $/MWh)**

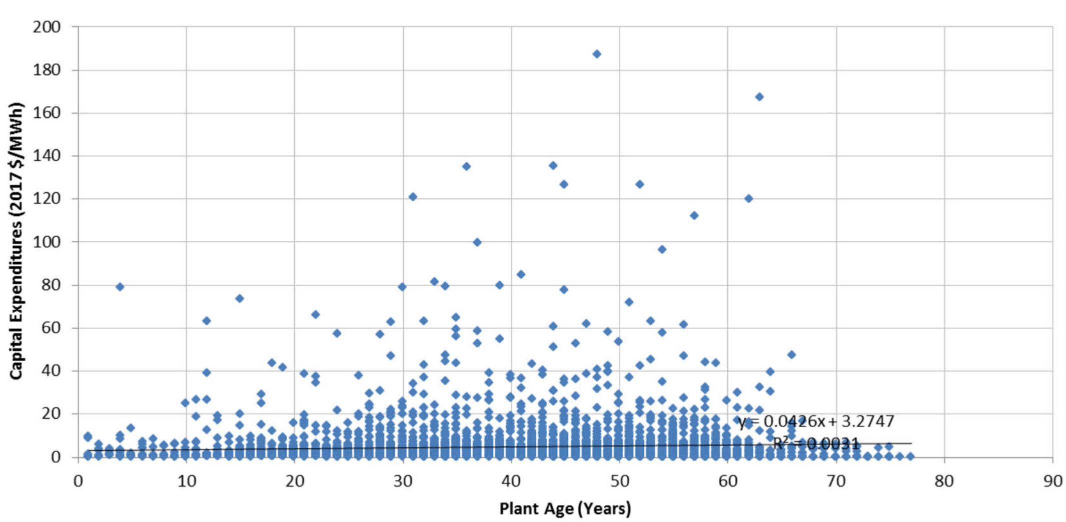
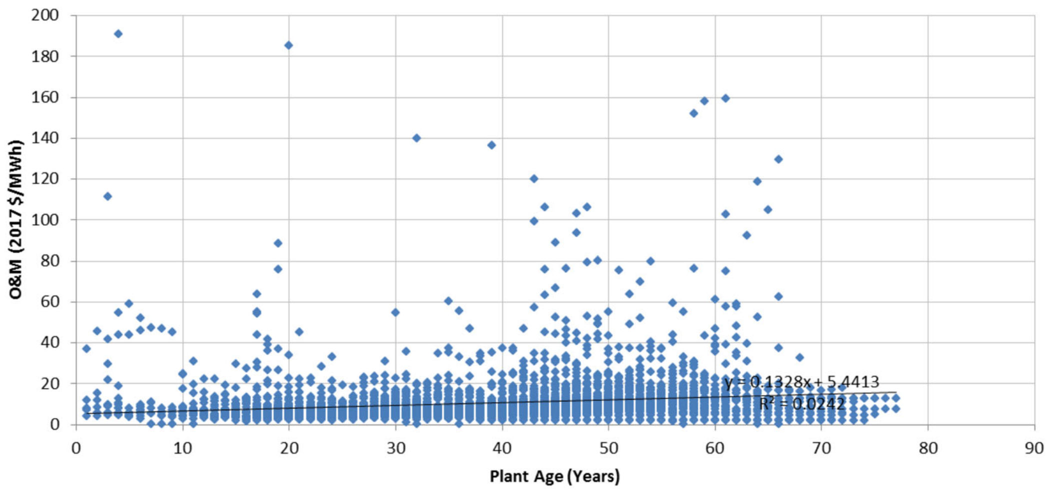
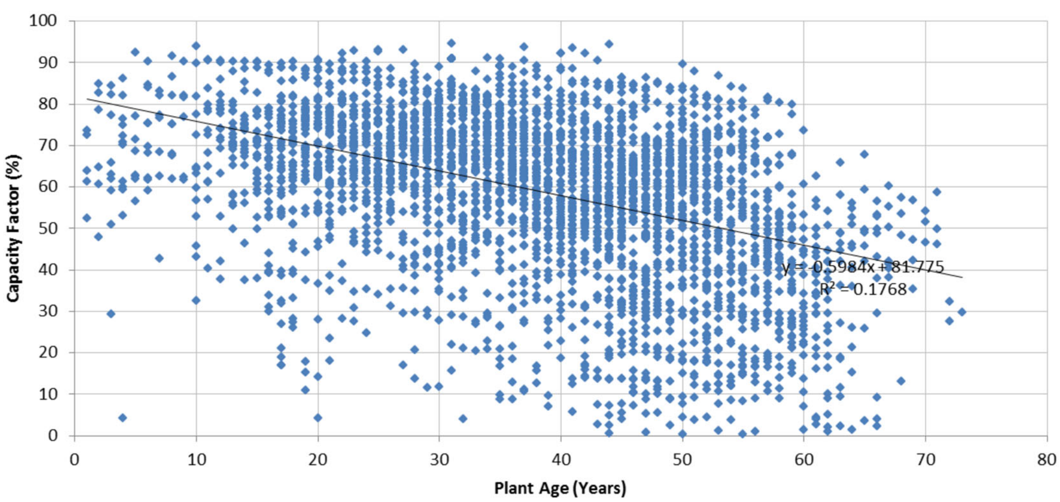


**Figure A-22 — O&M vs. Age for All Coal Plants (2017 $/MWh)**

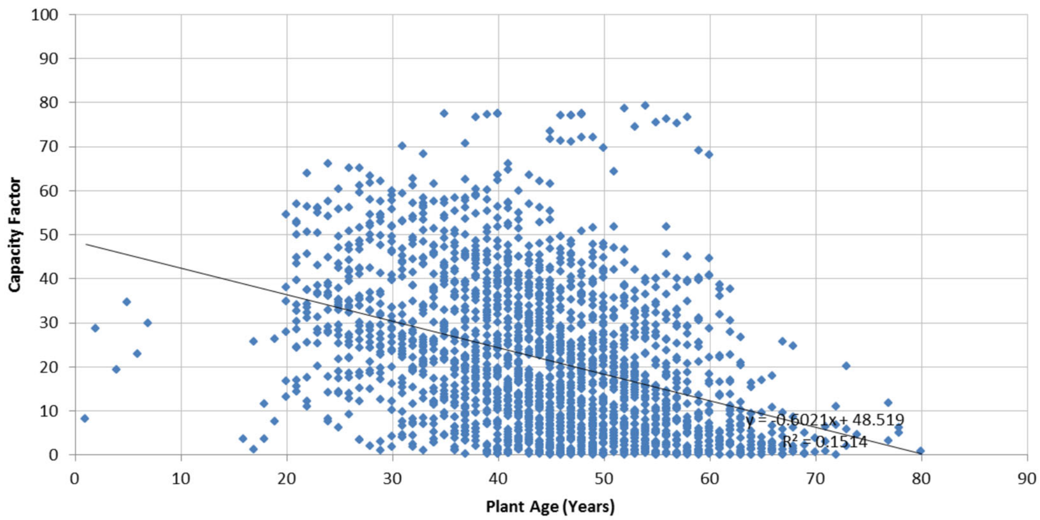



In both of the above regression results, the age coefficient was found to be statistically significant. This was determined to be a result of the average decline in capacity factors for the coal steam plants, as shown in Figure A-23. A similar decline also occurred with the gas/oil steam plants, as shown in Figure A-24.

**Figure A-23 — Capacity Factor vs. Age for All Coal Plants**



## Figure A-24 — Capacity Factor vs. Age for All Gas/Oil Steam Plants



# Appendix B. Regression Analysis – Gas/Oil Steam

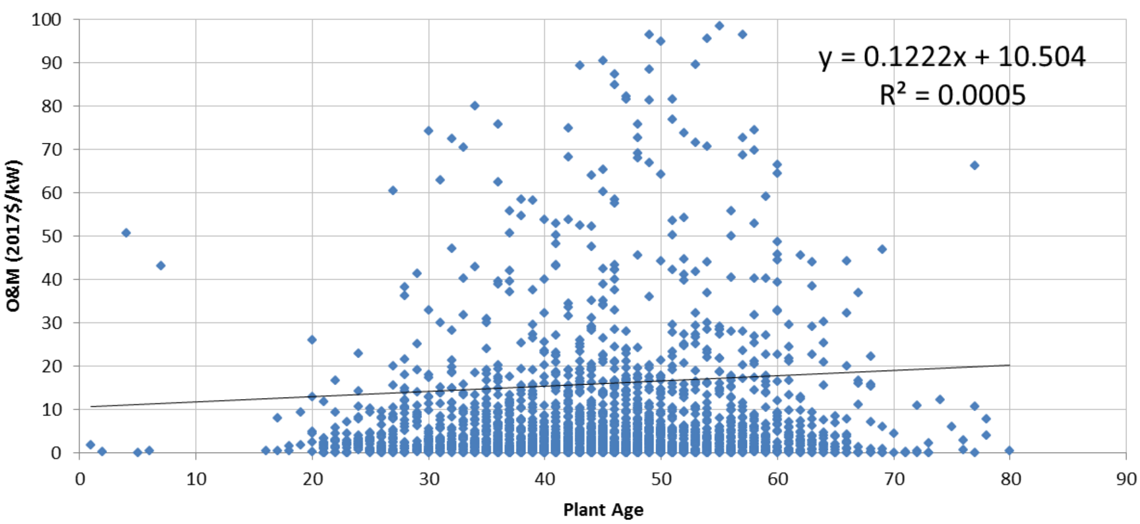
## CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.29, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

### Table B-1 — Regression Statistics – Gas/Oil Steam CAPEX for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 2,226 | | |
| **Simple Average ($/kW)** | 15.955 | | |
| **Intercept** | 10.504 | 1.9741 | 4.85E-02 |
| **Slope** | 0.122 | 1.0551 | 2.91E-01 |
| **$R^2$** | 0.00050 | | |

### Figure B-1 — Gas/Oil Steam Dataset – CAPEX for All Plant MW Sizes




Note: Age coefficient in above regression equation is not statistically significant.

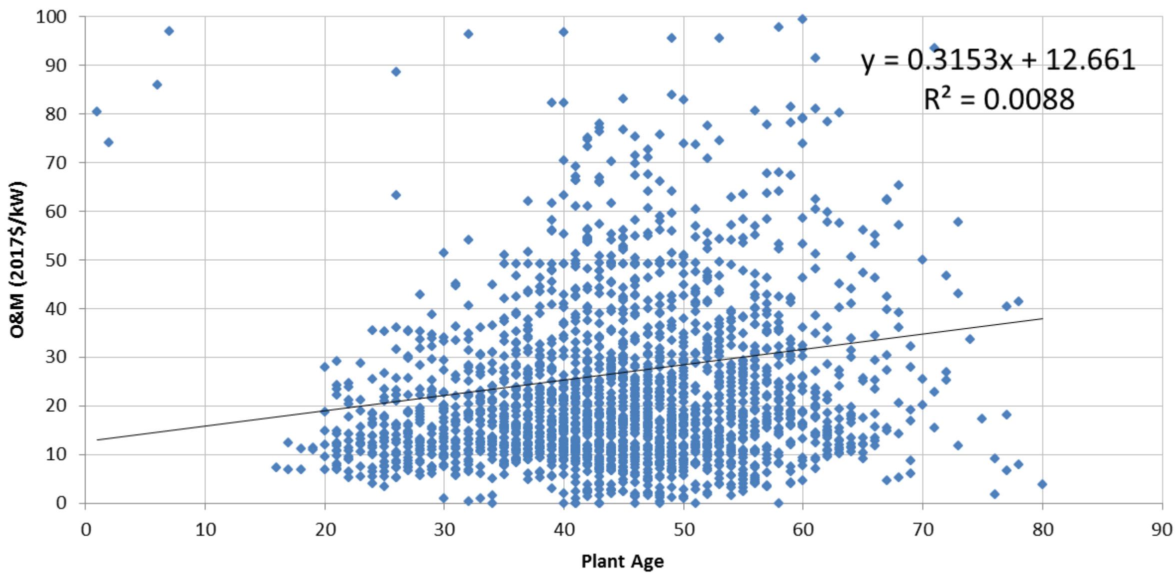
## OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for gas/oil steam plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the limited number of data points before year 20 may distort the regression analysis.

**Table B-2 — Regression Statistics – Gas/Oil Steam O&M for All MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 2,224 | | |
| **Simple Average ($/kW)** | 26.723 | | |
| **Intercept** | 12.661 | 3.8863 | 1.05E-04 |
| **Slope** | 0.315 | 4.4455 | 9.20E-06 |
| **$R^2$** | 0.00882 | | |

**Figure B-2 — Gas/Oil Steam Dataset – O&M for All Plant MW Sizes**




Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 39.39 | 23.48 | 28.18 | **26.72** | 19 | 733 | 1,472 | **2,224** |
| Net Total Capex - 2017 $/kW | 8.91 | 14.18 | 16.93 | **15.96** | 19 | 733 | 1,474 | **2,226** |
| Net Total O&M and Capex - 2017 $/kW | 48.30 | 37.53 | 45.10 | **42.63** | 19 | 731 | 1,470 | **2,220** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

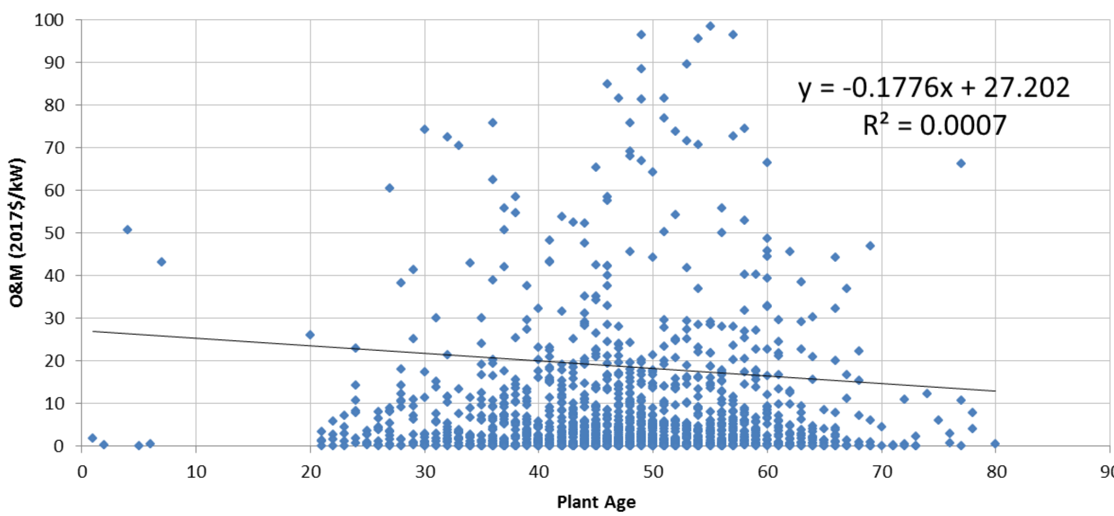
## CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.32, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table B-3 — Regression Statistics – Gas/Oil Steam CAPEX < 500 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1382 | | |
| **Simple Average ($/kW)** | 18.392 | | |
| **Intercept** | 27.202 | 3.1265 | 1.81E-03 |
| **Slope** | -0.178 | -0.9867 | 3.24E-01 |
| **$R^2$** | 0.00071 | | |

**Figure B-3 — Gas/Oil Steam Dataset – CAPEX for Less than 500-MW Plant Size**




Note: Age coefficient in above regression equation is not statistically significant.

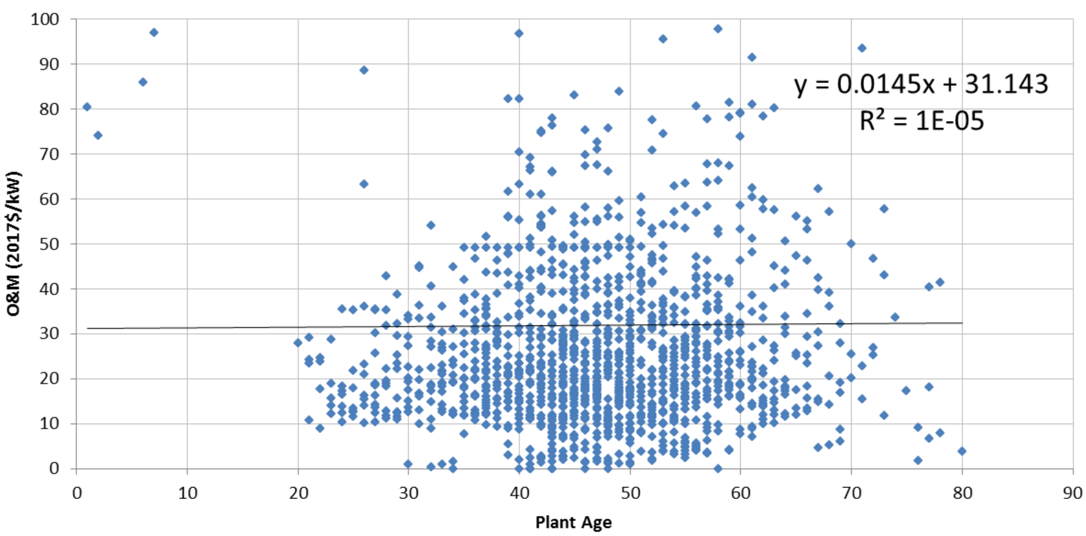
## OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

The results of the linear regression analysis of O&M spending for gas/oil steam plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.90, which is greater than 0.05, age is not a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

## Table B-4 — Regression Statistics – Gas/Oil Steam O&M < 500 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,381 | | |
| **Simple Average ($/kW)** | 31.827 | | |
| **Intercept** | 31.143 | 5.7925 | 8.58E-09 |
| **Slope** | 0.015 | 0.1305 | 8.96E-01 |
| **$R^2$** | 0.00001 | | |

## Figure B-4 — Gas/Oil Steam Dataset – O&M for Less than 500-MW Plant Size




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **< 500 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 88.54 | 33.36 | 30.98 | **31.83** | 7 | 324 | 1,050 | **1,381** |
| Net Total Capex - 2017 $/kW | 17.44 | 22.13 | 17.82 | **18.83** | 7 | 324 | 1,051 | **1,382** |
| Net Total O&M and Capex - 2017 $/kW | 105.98 | 55.32 | 48.78 | **50.60** | 7 | 322 | 1,048 | **1,377** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

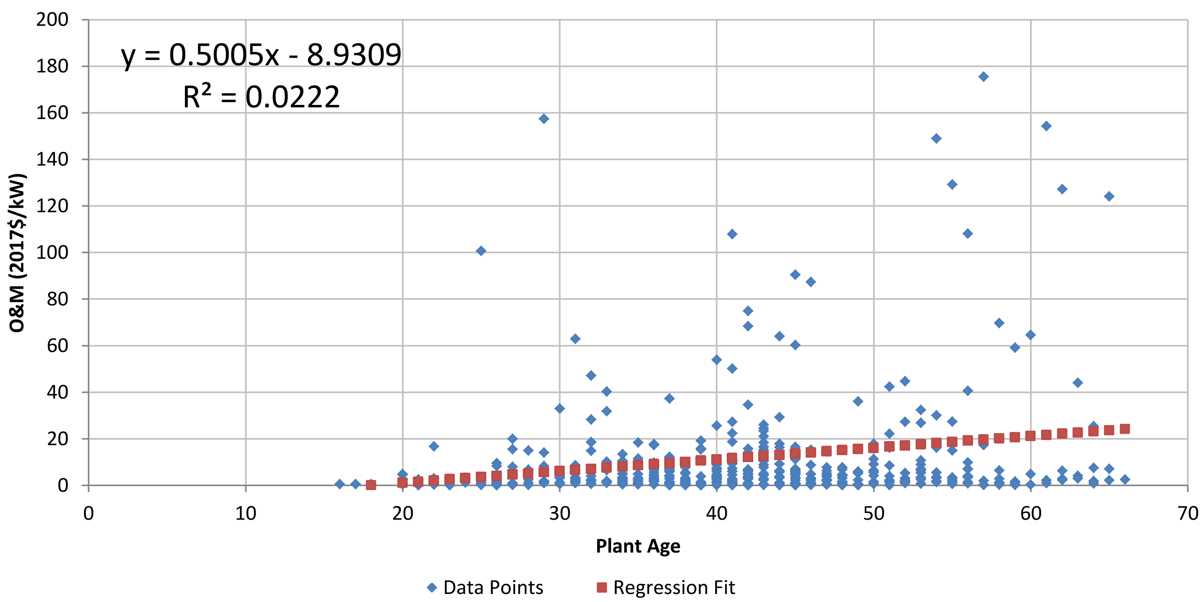
## CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of CAPEX spending. However, the regression analysis shows the intercept value (i.e., the CAPEX cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited amount of data causes the regression analysis to be distorted and unrealistic.

### Table B-5 — Regression Statistics – Gas/Oil Steam CAPEX 500 MW to 1,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 489 | | |
| **Simple Average ($/kW)** | 11.570 | | |
| **Intercept** | -8.988 | -1.4118 | 1.59E-01 |
| **Slope** | 0.501 | 3.3322 | 9.27E-04 |
| **$R^2$** | 0.02229 | | |

### Figure B-5 — Gas/Oil Steam Dataset – CAPEX for 500-MW to 1,000-MW Plant Size



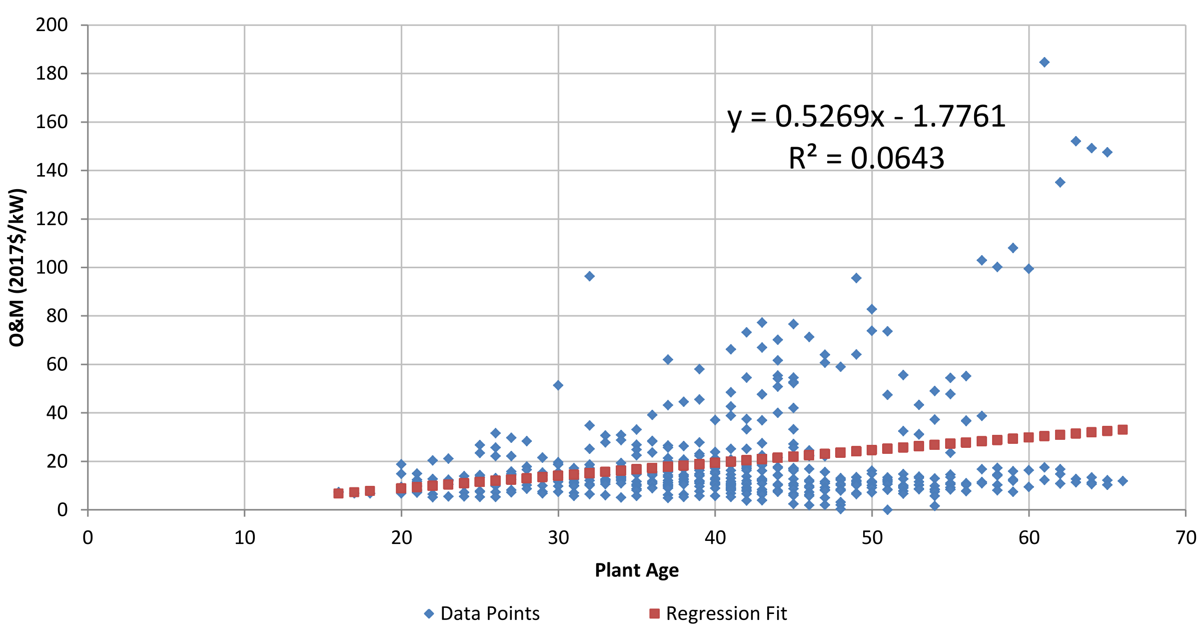
## OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of O&M spending for gas/oil steam plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending. However, the regression analysis shows the intercept value (i.e., the O&M cost during the first year) to be less than zero. This is because of the lack of data for plant ages up to 20 years—the limited data causes the regression analysis to be distorted.

### Table B-6 — Regression Statistics – Gas/Oil Steam O&M 500 MW to 1,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 488 | | |
| **Simple Average ($/kW)** | 19.823 | | |
| **Intercept** | -1.776 | -0.4606 | 6.45E-01 |
| **Slope** | 0.527 | 5.7810 | 1.33E-08 |
| **$R^2$** | 0.06434 | | |

### Figure B-6 — Gas/Oil Steam Dataset – O&M for 500-MW to 1,000-MW Plant Size




The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **500 MW - 1000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 10.10 | 15.82 | 23.61 | **19.82** | 7 | 225 | 256 | **488** |
| Net Total Capex - 2017 $/kW | 1.94 | 6.32 | 16.43 | **11.57** | 7 | 225 | 257 | **489** |
| Net Total O&M and Capex - 2017 $/kW | 12.04 | 22.14 | 40.07 | **31.40** | 7 | 225 | 256 | **488** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

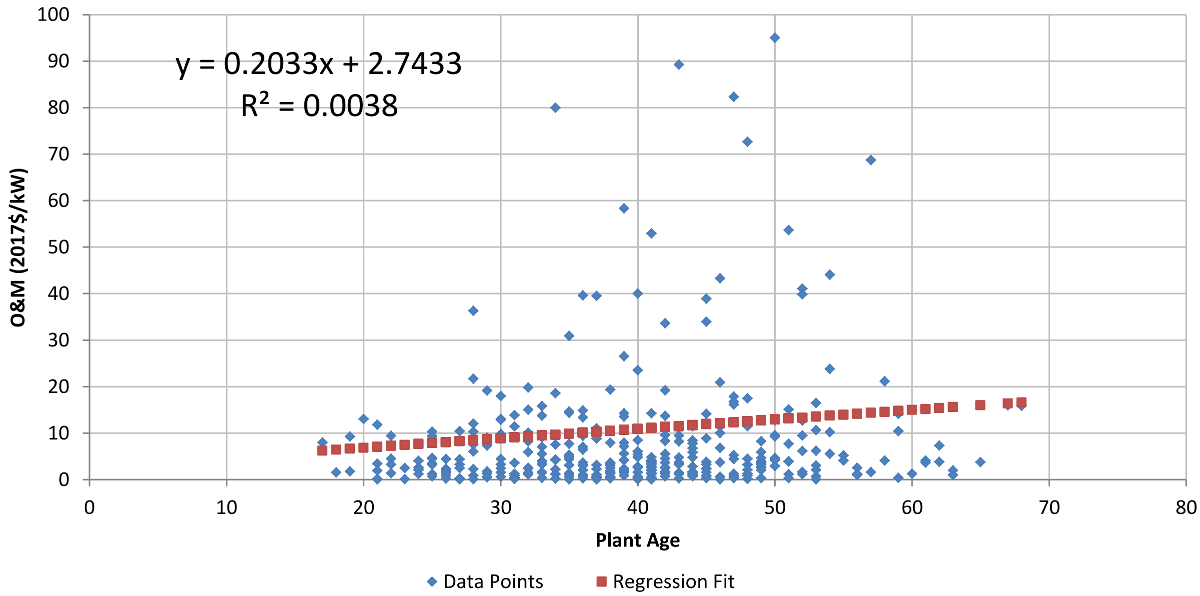
## CAPITAL EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil steam plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.24, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table B-7 — Regression Statistics – Gas/Oil Steam CAPEX > 1,000 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 355 | | |
| **Simple Average ($/kW)** | 10.815 | | |
| **Intercept** | 2.743 | 0.3846 | 7.01E-01 |
| **Slope** | 0.203 | 1.1660 | 2.44E-01 |
| **$R^2$** | 0.00384 | | |

**Figure B-7 — Gas/Oil Steam Dataset – CAPEX for Greater than 1,000-MW Plant Size**




Note: Age coefficient in above regression equation is not statistically significant.

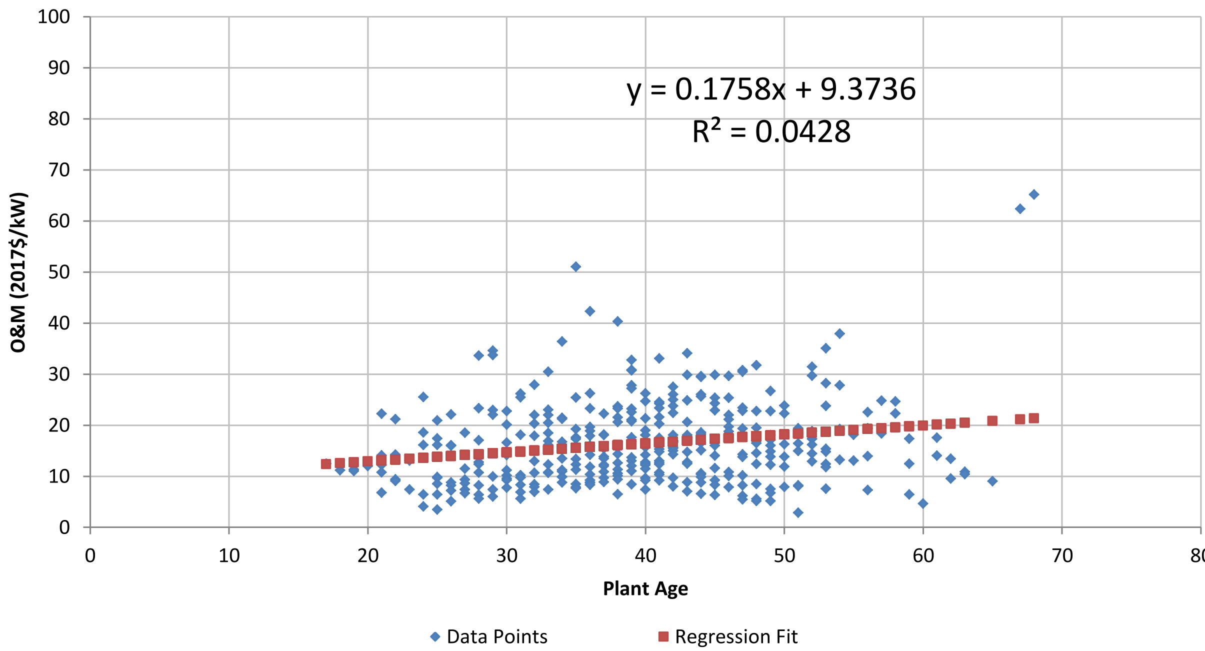
## OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of O&M spending for gas/oil steam plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the limited number of data points before year 20 may distort the regression analysis.

**Table B-8 — Regression Statistics – Gas/Oil Steam O&M > 1,000 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 355 | | |
| **Simple Average ($/kW)** | 16.353 | | |
| **Intercept** | 9.374 | 5.1812 | 3.71E-07 |
| **Slope** | 0.176 | 3.9752 | 8.53E-05 |
| **$R^2$** | 0.04285 | | |

### Figure B-8 — Gas/Oil Steam Dataset – O&M for Greater than 1,000-MW Plant Size




The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 \$/kW-year, are summarized in the table below.

| | Average \$/kW (years 1 - 20) = | Average \$/kW (years 21 - 40) = | Average \$/kW (years 41 - 80) = | **Average \$/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **> 1000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 \$/kW | 11.59 | 15.44 | 17.50 | **16.35** | 5 | 184 | 166 | **355** |
| Net Total Capex - 2017 \$/kW | 6.70 | 9.78 | 12.09 | **10.82** | 5 | 184 | 166 | **355** |
| Net Total O&M and Capex - 2017 \$/kW | 18.29 | 25.22 | 29.60 | **27.17** | 5 | 184 | 166 | **355** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil steam plants are described in Section 4.

# Appendix C. Regression Analysis – Gas/Oil Combined Cycle

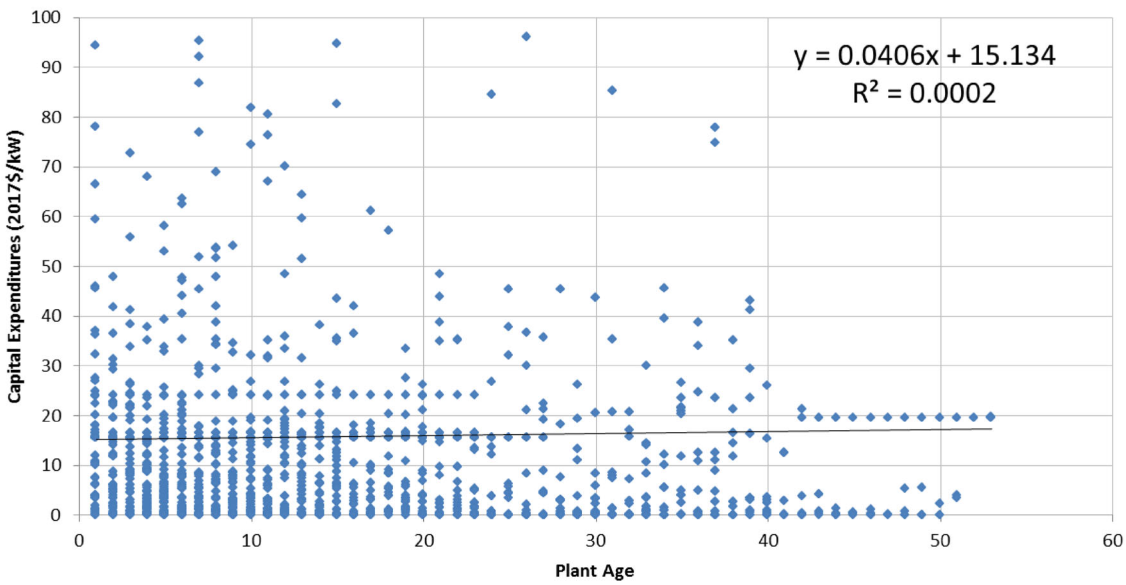
## CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.63, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

### Table C-1 — Regression Statistics – CC CAPEX for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,368 | | |
| **Simple Average ($/kW)** | 15.765 | | |
| **Intercept** | 15.134 | 9.2176 | 1.11E-19 |
| **Slope** | 0.041 | 0.4853 | 6.28E-01 |
| **$R^2$** | 0.00017 | | |

### Figure C-1 — Gas/Oil CC Dataset – CAPEX for All Plant MW Sizes




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

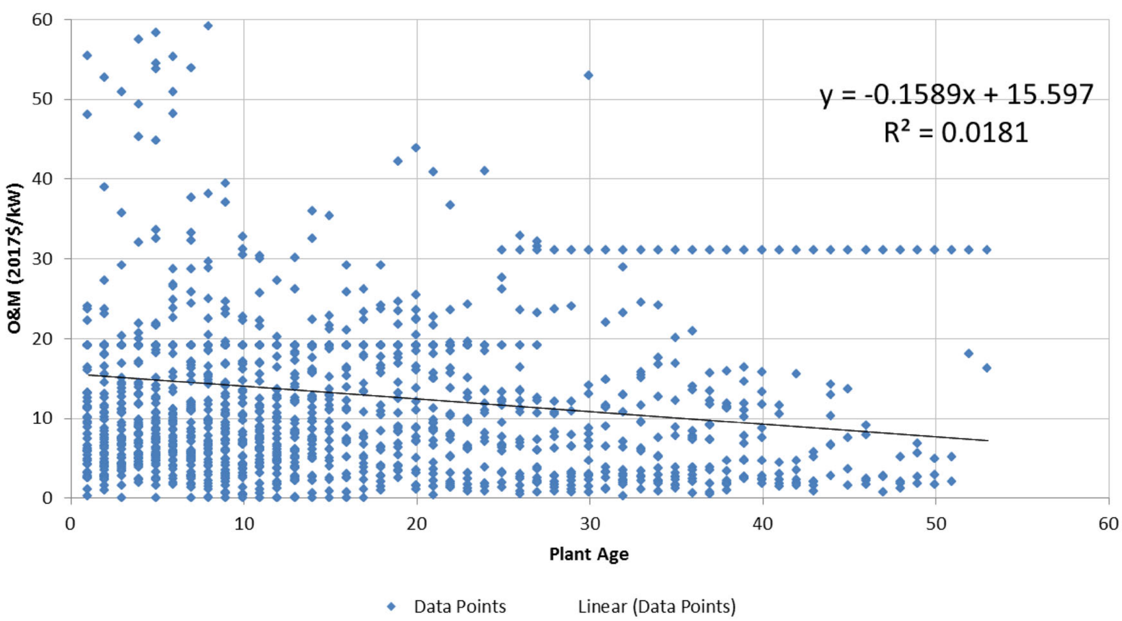
## OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is much lower than 0.05, the dataset appears to support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

## Table C-2 — Regression Statistics – CC O&M for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,388 | | |
| **Simple Average ($/kW)** | 13.080 | | |
| **Intercept** | 15.597 | 24.8961 | 2.19E-113 |
| **Slope** | -0.159 | -5.0573 | 4.82E-07 |
| **$R^2$** | 0.01812 | | |

## Figure C-2 — Gas/Oil CC Dataset – O&M for All Plant MW Sizes




Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 14.16 | 10.56 | 10.26 | **13.08** | 978 | 344 | 66 | **1,388** |
| Net Total Capex - 2017 $/kW | 15.45 | 16.37 | 17.56 | **15.76** | 979 | 326 | 63 | **1,368** |
| Net Total O&M and Capex - 2017 $/kW | 29.64 | 27.24 | 28.19 | **29.00** | 976 | 326 | 63 | **1,365** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

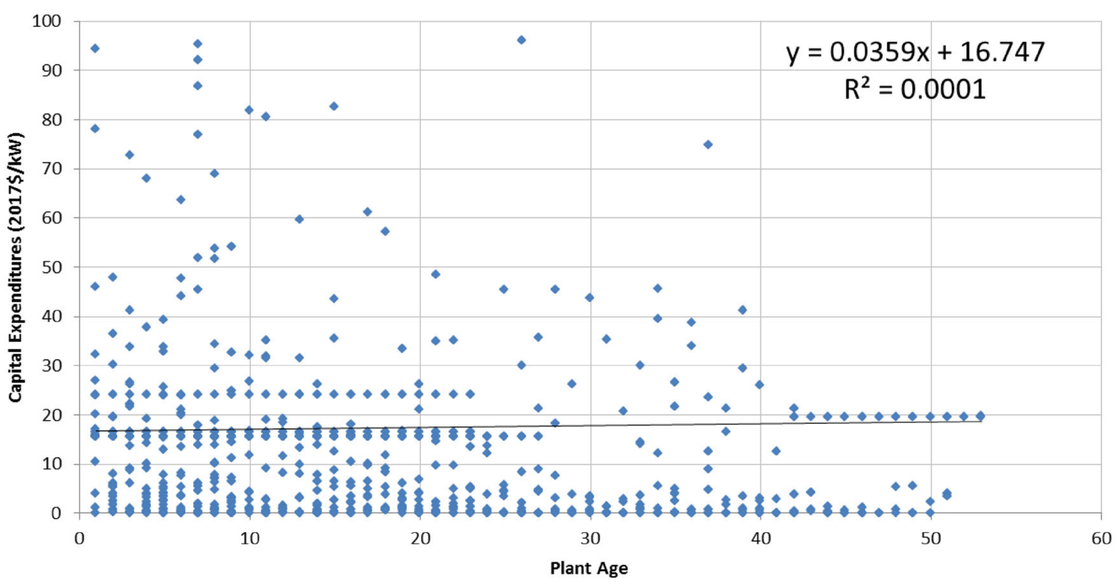
## CAPITAL EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants under 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.76, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table C-3 — Regression Statistics – CC CAPEX < 500 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 765 | | |
| **Simple Average ($/kW)** | 17.378 | | |
| **Intercept** | 16.747 | 6.4870 | 1.57E-10 |
| **Slope** | 0.036 | 0.3007 | 7.64E-01 |
| **$R^2$** | 0.00012 | | |

**Figure C-3 — Gas/Oil CC Dataset – CAPEX for Less than 500-MW Plant Size**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

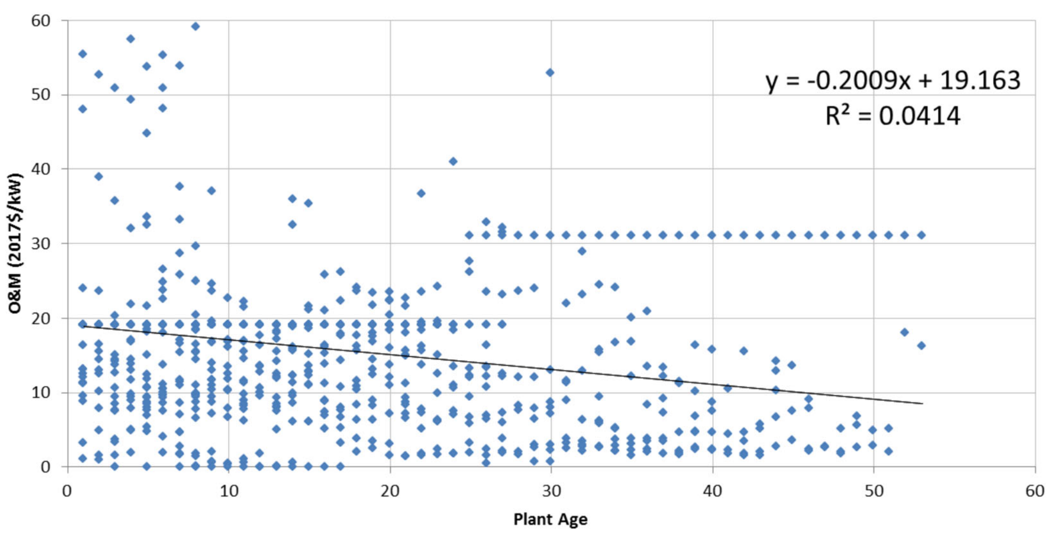
## OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 500 MW

The results of the regression analysis of O&M spending for gas/oil CC plants less than 500 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

### Table C-4 — Regression Statistics – CC O&M < 500 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 766 | | |
| **Simple Average ($/kW)** | 15.619 | | |
| **Intercept** | 19.163 | 25.2973 | 4.82E-103 |
| **Slope** | -0.201 | -5.7467 | 1.31E-08 |
| **$R^2$** | 0.04143 | | |

### Figure C-4 — Gas/Oil CC Dataset – O&M for Less than 500-MW Plant Size




Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **< 500 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 17.10 | 13.01 | 12.27 | **15.62** | 498 | 216 | 52 | **766** |
| Net Total Capex - 2017 $/kW | 16.83 | 17.78 | 21.01 | **17.38** | 499 | 214 | 52 | **765** |
| Net Total O&M and Capex - 2017 $/kW | 34.00 | 30.72 | 33.28 | **33.03** | 497 | 214 | 52 | **763** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

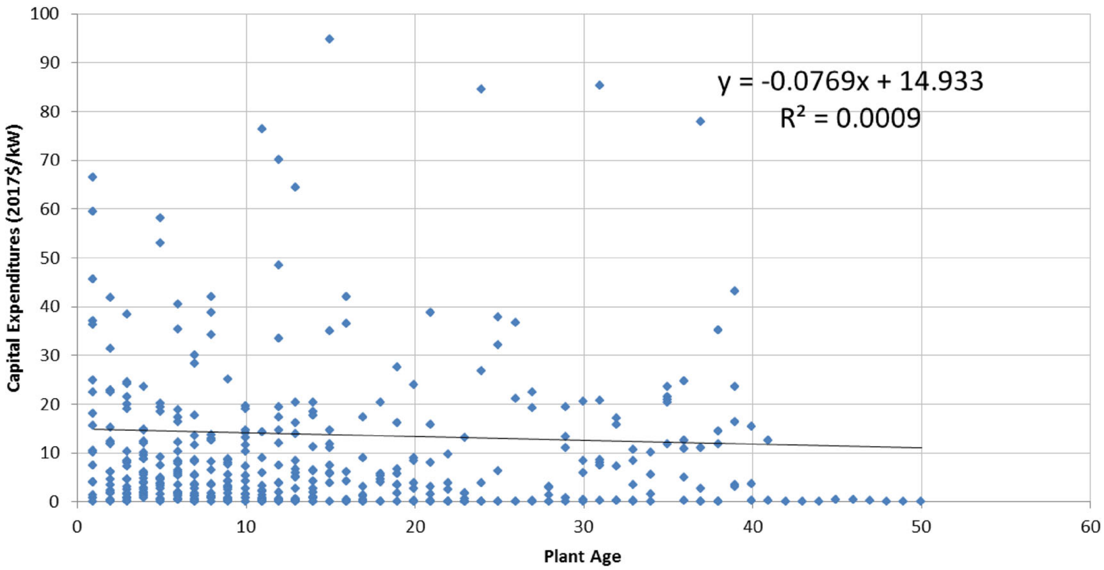
## CAPITAL EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.52, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

### Table C-5 — Regression Statistics – CC CAPEX 500 MW to 1,000 MW

| | | ***t statistic*** | ***p-value*** |
|---|---|---|---|
| **Observations** | 426 | | |
| **Simple Average ($/kW)** | 13.780 | | |
| **Intercept** | 14.933 | 6.3972 | 4.19E-10 |
| **Slope** | -0.077 | -0.6252 | 5.32E-01 |
| **$R^2$** | 0.00092 | | |

### Figure C-5 — Gas/Oil CC Dataset – CAPEX for 500-MW to 1,000-MW Plant Size




Note: Age coefficient in above regression equation is not statistically significant.

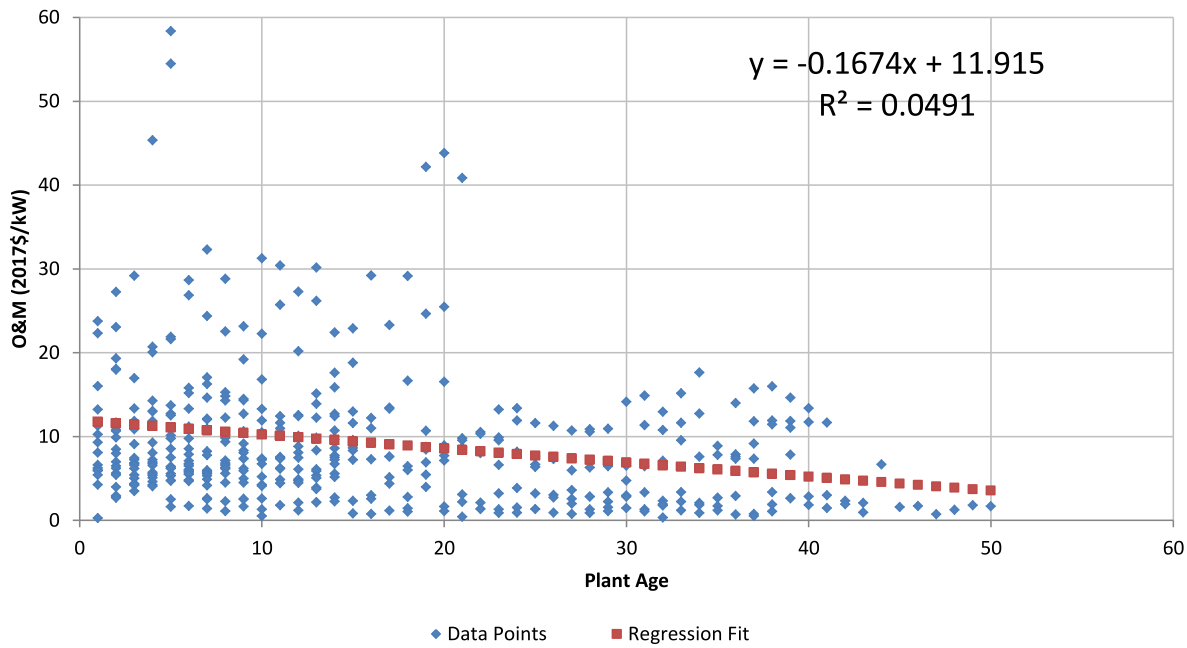
## OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 500 MW AND 1,000 MW

The results of the regression analysis of O&M spending for gas/oil CC plants between 500 MW and 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

### Table C-6 — Regression Statistics – CC O&M 500 MW to 1,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 445 | | |
| **Simple Average ($/kW)** | 9.269 | | |
| **Intercept** | 11.915 | 17.1008 | 1.04E-50 |
| **Slope** | -0.167 | -4.7810 | 2.38E-06 |
| **$R^2$** | 0.04907 | | |

**Figure C-6 — Gas/Oil CC Dataset – O&M for 500-MW to 1,000-MW Plant Size**




The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **500 MW - 1000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 10.68 | 6.50 | 2.78 | **9.27** | 307 | 124 | 14 | **445** |
| Net Total Capex - 2017 $/kW | 14.38 | 13.36 | 1.28 | **13.78** | 307 | 108 | 11 | **426** |
| Net Total O&M and Capex - 2017 $/kW | 25.06 | 20.38 | 4.15 | **23.33** | 306 | 108 | 11 | **425** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

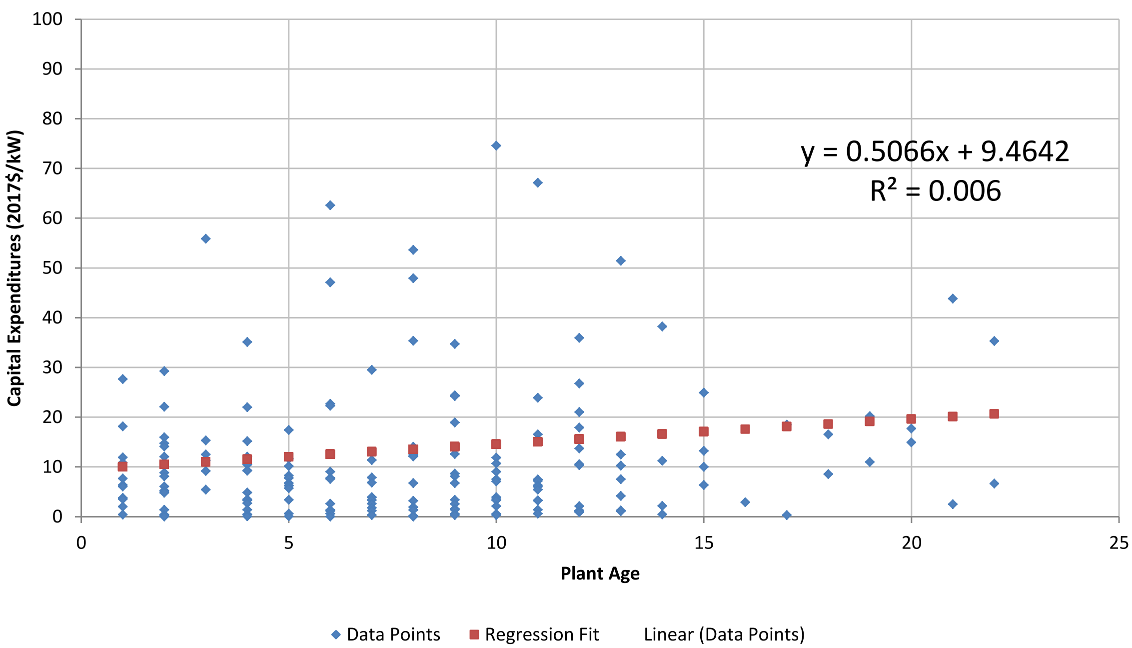
## CAPITAL EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of CAPEX spending for gas/oil CC plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.30, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table C-7 — Regression Statistics – CC CAPEX > 1,000 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 177 | | |
| **Simple Average ($/kW)** | 13.566 | | |
| **Intercept** | 9.464 | 2.0308 | 4.38E-02 |
| **Slope** | 0.507 | 1.0309 | 3.04E-01 |
| **$R^2$** | 0.00604 | | |

**Figure C-7 — Gas/Oil CC Dataset – CAPEX for Greater than 1,000-MW Plant Size**




Note: Age coefficient in above regression equation is not statistically significant.

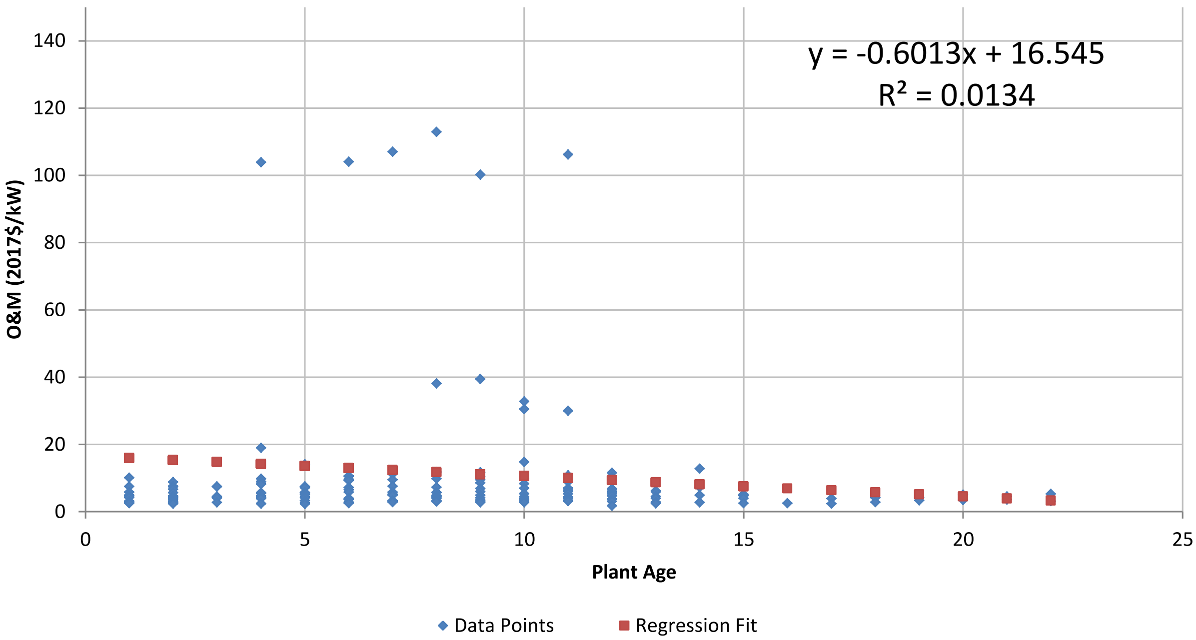
## OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 1,000 MW

The results of the regression analysis of O&M spending for gas/oil CC plants greater than 1,000 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.13, which is greater than 0.05, age is not a statistically significant predictor of O&M spending.

## Table C-8 — Regression Statistics – CC O&M > 1,000 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 177 | | |
| **Simple Average ($/kW)** | 11.676 | | |
| **Intercept** | 16.545 | 4.4651 | 1.43E-05 |
| **Slope** | -0.601 | -1.5389 | 1.26E-01 |
| **$R^2$** | 0.01335 | | |

## Figure C-8 — Gas/Oil CC Dataset – O&M for Greater than 1,000 MW Plant Size




Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **> 1000 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 11.85 | 4.14 | - | **11.68** | 173 | 4 | 0 | **177** |
| Net Total Capex - 2017 $/kW | 13.37 | 22.06 | - | **13.57** | 173 | 4 | 0 | **177** |
| Net Total O&M and Capex - 2017 $/kW | 25.22 | 26.20 | - | **25.24** | 173 | 4 | 0 | **177** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

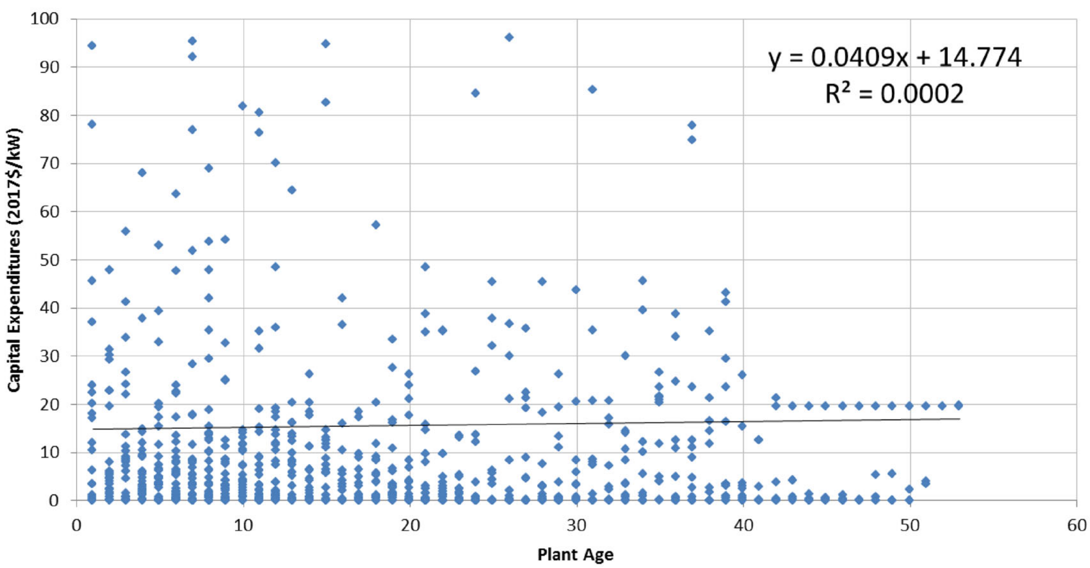
## CAPITAL EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors under 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient (“slope”) is 0.71, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table C-9 — Regression Statistics – CC CAPEX for Capacity Factor < 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 844 | | |
| **Simple Average ($/kW)** | 15.554 | | |
| **Intercept** | 14.774 | 5.7075 | 1.59E-08 |
| **Slope** | 0.041 | 0.3659 | 7.15E-01 |
| **$R^2$** | 0.00016 | | |

**Figure C-9 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor < 50%**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

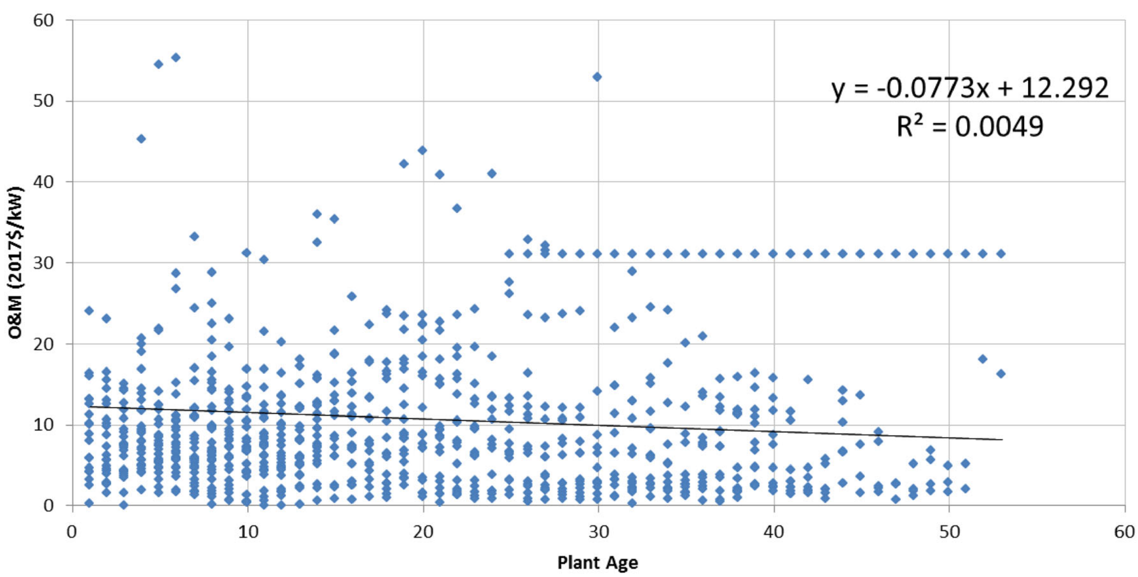
## OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR LESS THAN 50%

The results of the regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors under 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). However, the outliers before year 20 and relatively low number of data points after year 40 may distort the regression analysis.

**Table C-10 — Regression Statistics – CC O&M for Capacity Factor < 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 864 | | |
| **Simple Average ($/kW)** | 10.791 | | |
| **Intercept** | 12.292 | 13.9850 | 3.33E-40 |
| **Slope** | -0.077 | -2.0625 | 3.95E-02 |
| **$R^2$** | 0.00491 | | |

**Figure C-10 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor < 50%**




Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, Capacity Factors 0 - 50%** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 11.54 | 9.65 | 10.26 | **10.79** | 500 | 298 | 66 | **864** |
| Net Total Capex - 2017 $/kW | 15.35 | 15.46 | 17.56 | **15.55** | 501 | 280 | 63 | **844** |
| Net Total O&M and Capex - 2017 $/kW | 26.95 | 25.41 | 28.19 | **26.53** | 499 | 280 | 63 | **842** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

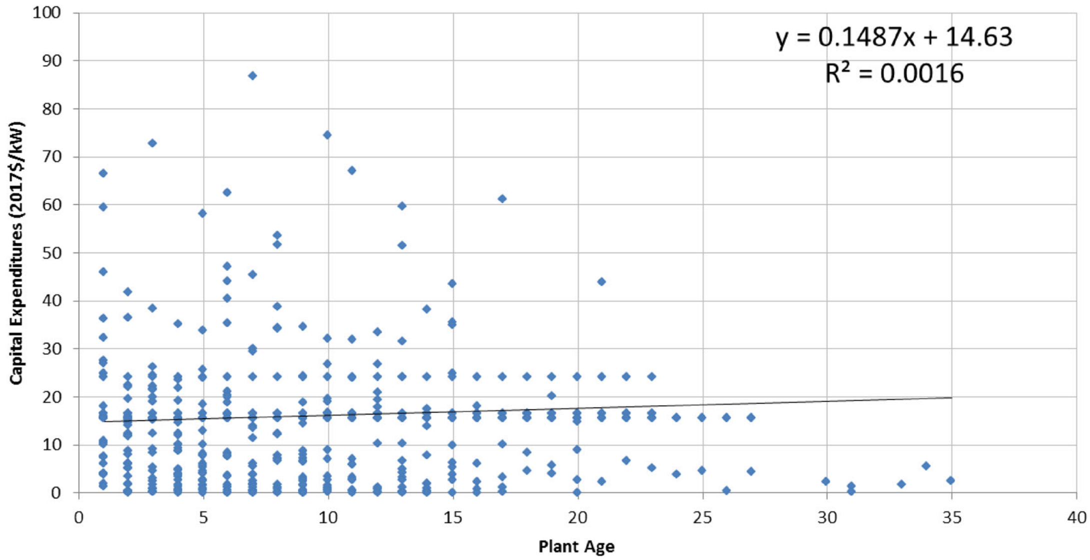
## CAPITAL EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the regression analysis of CAPEX spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors greater than 50% are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.37, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

**Table C-11 — Regression Statistics – CC CAPEX for Capacity Factor > 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 524 | | |
| **Simple Average ($/kW)** | 16.104 | | |
| **Intercept** | 14.630 | 7.3893 | 5.90E-13 |
| **Slope** | 0.149 | 0.9054 | 3.66E-01 |
| **$R^2$** | 0.00157 | | |

**Figure C-11 — CC Dataset – CAPEX for All Plant Sizes and Avg. Net Capacity Factor > 50%**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

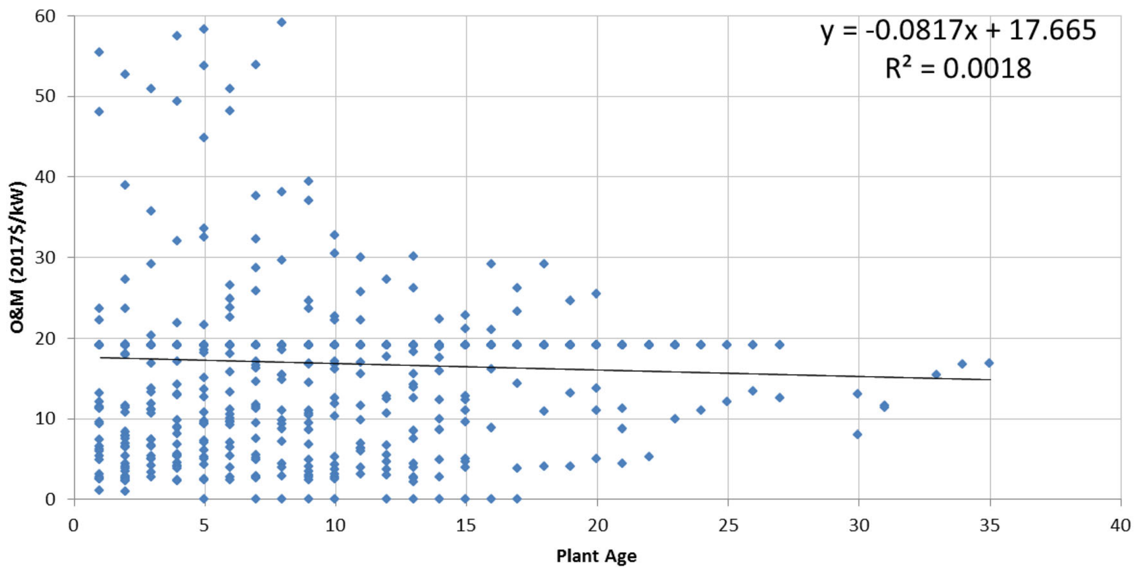
## OPERATIONS & MAINTENANCE EXPENDITURES – CAPACITY FACTOR GREATER THAN 50%

The results of the linear regression analysis of O&M spending for gas/oil CC plants of all MW sizes (full dataset) with capacity factors greater than 50% are summarized in the table below. Since the p-value for the age coefficient ("slope") is 0.33, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

**Table C-12 — Regression Statistics – CC O&M for Capacity Factor > 50%**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 524 | | |
| **Simple Average ($/kW)** | 16.855 | | |
| **Intercept** | 17.665 | 17.5298 | 1.93E-54 |
| **Slope** | -0.082 | -0.9777 | 3.29E-01 |
| **$R^2$** | 0.00183 | | |

**Figure C-12 — CC Dataset – O&M for All Plant Sizes and Avg. Net Capacity Factor > 50%**




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, Capacity Factors 50% - 100%** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 16.90 | 16.44 | - | **16.85** | 478 | 46 | 0 | **524** |
| Net Total Capex - 2017 $/kW | 15.55 | 21.89 | - | **16.10** | 478 | 46 | 0 | **524** |
| Net Total O&M and Capex - 2017 $/kW | 32.46 | 38.32 | - | **32.98** | 477 | 46 | 0 | **523** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CC plants are described in Section 5.

# Appendix D. Regression Analysis – Gas/Oil Combustion Turbine

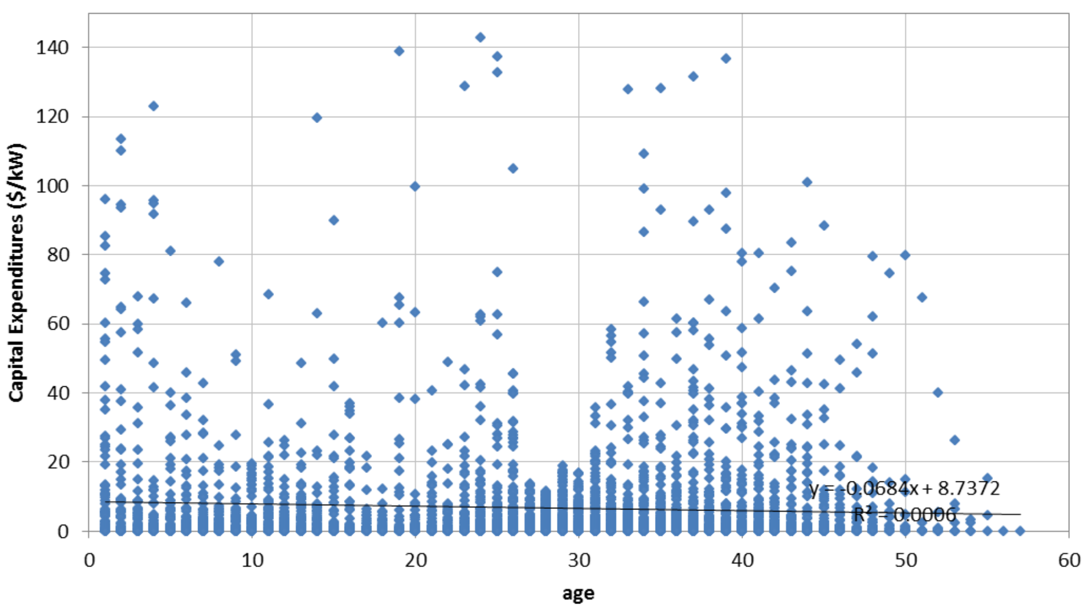
## CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of CAPEX spending for gas/oil CT plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.09, which is greater than 0.05, dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

### Table D-1 — Regression Statistics – CT CAPEX for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 5065 | | |
| **Simple Average ($/kW)** | 6.897 | | |
| **Intercept** | 8.737 | 7.3087 | 3.12E-13 |
| **Slope** | -0.068 | -1.6948 | 9.02E-02 |
| **$R^2$** | 0.00057 | | |

### Figure D-1 — Gas/Oil CT Dataset – CAPEX for All Plant MW Sizes




Note: Age coefficient in above regression equation is not statistically significant.

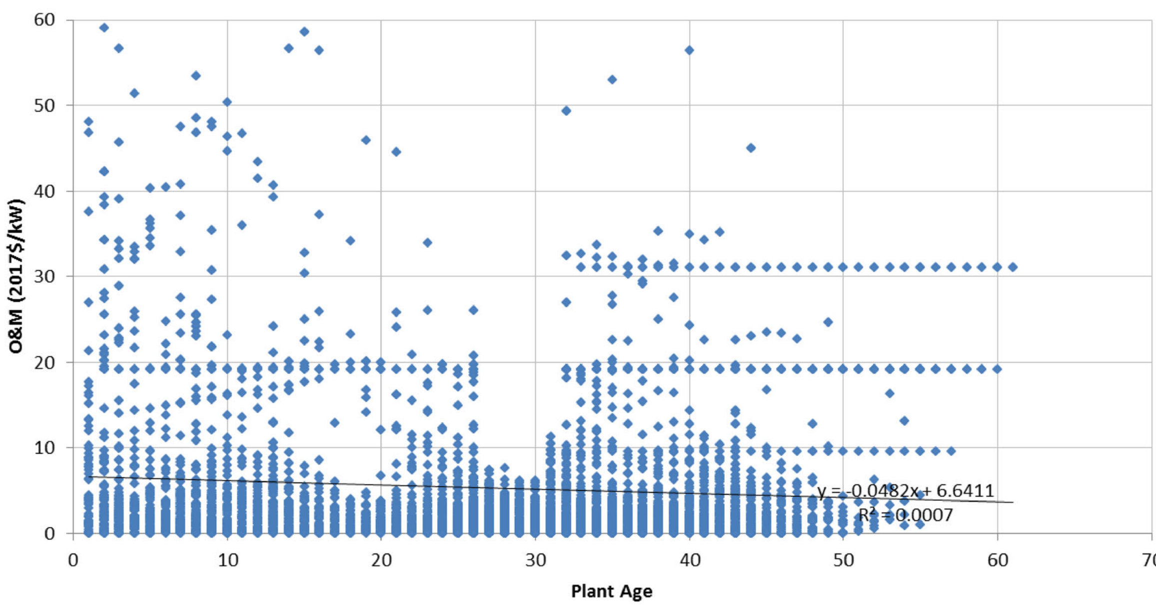
## OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the regression analysis of O&M spending for gas/oil CT plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.062, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

### Table D-2 — Regression Statistics – CT O&M for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 5283 | | |
| **Simple Average ($/kW)** | 5.331 | | |
| **Intercept** | 6.641 | 8.5764 | 1.27E-17 |
| **Slope** | -0.048 | -1.8683 | 6.18E-02 |
| **$R^2$** | 0.00066 | | |

### Figure D-2 — Gas/Oil CT Dataset – O&M for All Plant MW Sizes




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 7.86 | 3.99 | 6.11 | **5.33** | 1,418 | 3,118 | 747 | **5,283** |
| Net Total Capex - 2017 $/kW | 9.17 | 5.78 | 7.40 | **6.90** | 1,360 | 3,054 | 651 | **5,065** |
| Net Total O&M and Capex - 2017 $/kW | 16.43 | 9.43 | 10.92 | **11.49** | 1,341 | 3,040 | 640 | **5,021** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

## CAPITAL EXPENDITURES – LESS THAN 100 MW

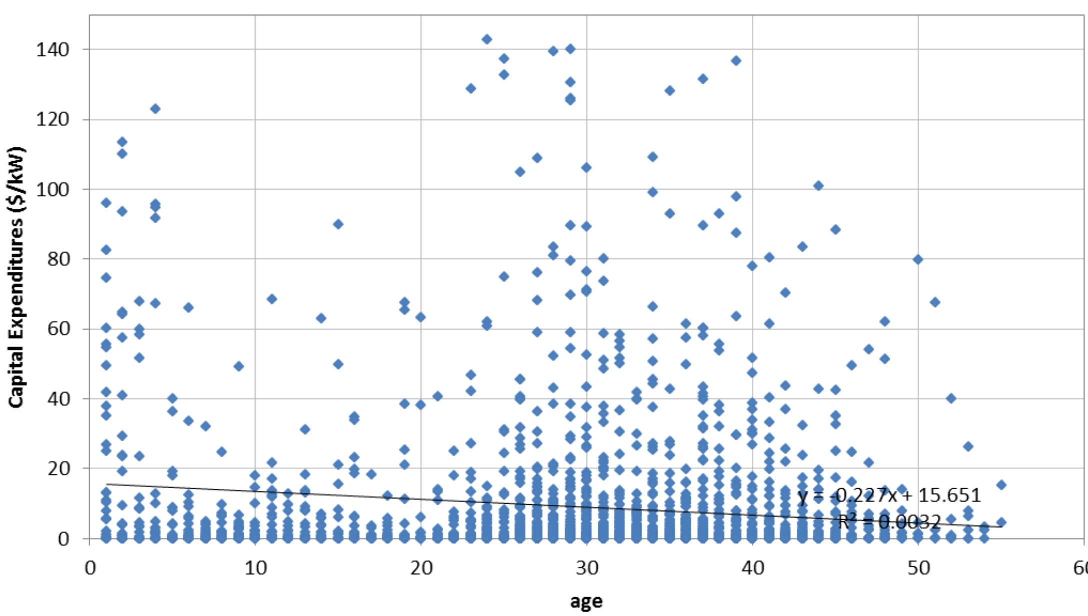
The results of the regression analysis of CAPEX spending for gas/oil CT plants less than 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.002, which is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

**Annual CAPEX spending in 2017 $/kW-year = 15.651 + (-0.227 × age)**

**Table D-3 — Regression Statistics – CT CAPEX < 100 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 2,911 | | |
| **Simple Average ($/kW)** | 9.003 | | |
| **Intercept** | 15.651 | 6.6753 | 2.94E-11 |
| **Slope** | -0.227 | -3.0345 | 2.43E-03 |
| **$R^2$** | 0.00316 | | |

**Figure D-3 — Gas/Oil CT Dataset – CAPEX for Less than 100-MW Plant Size**



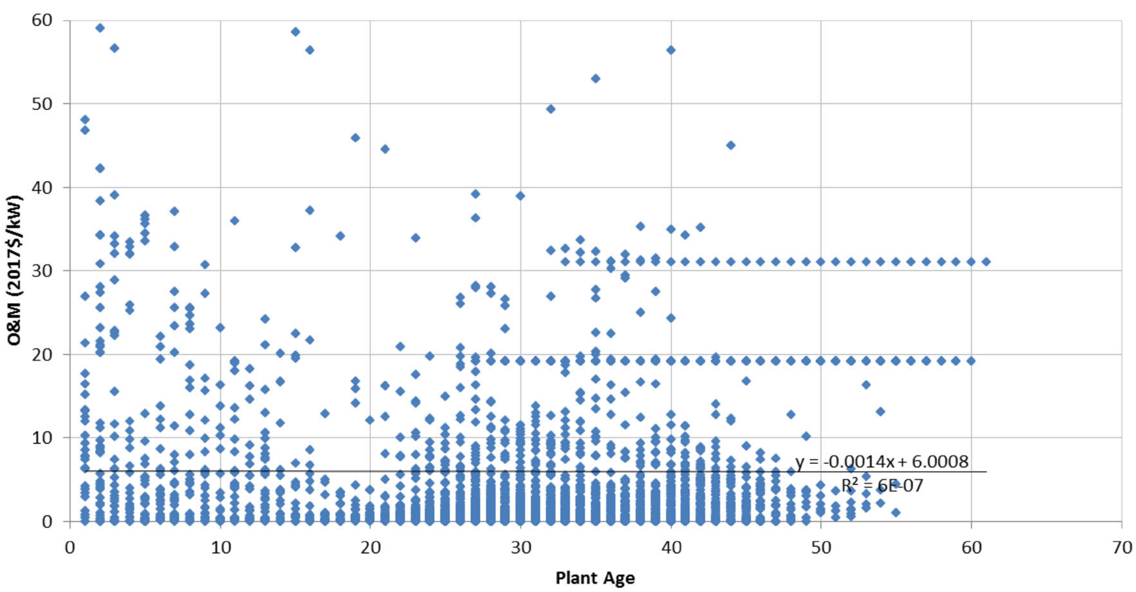
## OPERATIONS & MAINTENANCE EXPENDITURES – LESS THAN 100 MW

The results of the regression analysis of O&M spending for gas/oil CT plants less than 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.966, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

### Table D-4 — Regression Statistics – CT O&M < 100 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 3,062 | | |
| **Simple Average ($/kW)** | 5.958 | | |
| **Intercept** | 6.001 | 5.5008 | 4.09E-08 |
| **Slope** | -0.001 | -0.0423 | 9.66E-01 |
| **$R^2$** | 0.00000 | | |

### Figure D-4 — Gas/Oil CT Dataset – O&M for Less than 100-MW Plant Size




Notes: Age coefficient in above regression equation is not statistically significant.
Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **< 100 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 8.76 | 4.93 | 7.40 | **5.96** | 489 | 2,060 | 513 | **3,062** |
| Net Total Capex - 2017 $/kW | 15.08 | 7.98 | 6.64 | **9.00** | 497 | 1,999 | 415 | **2,911** |
| Net Total O&M and Capex - 2017 $/kW | 24.04 | 12.31 | 10.26 | **14.02** | 489 | 1,978 | 406 | **2,873** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

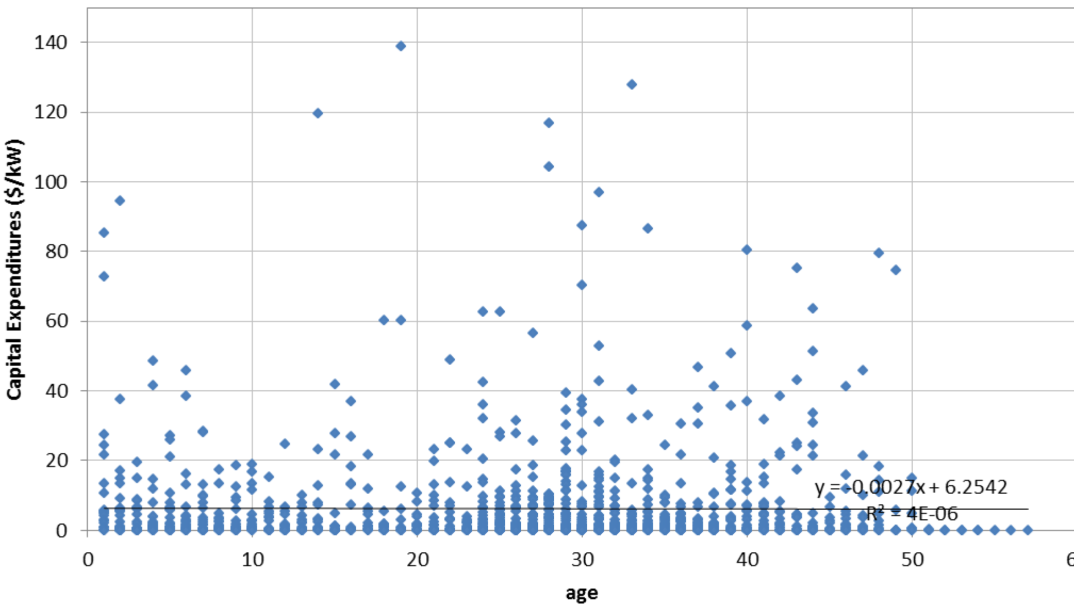
## CAPITAL EXPENDITURES – BETWEEN 100 MW AND 300 MW

The results of the regression analysis of CAPEX spending for CT plants between 100 MW and 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.939, which is greater than 0.05, age is not a statistically significant predictor of CAPEX spending.

### Table D-5 — Regression Statistics – CT CAPEX 100 MW to 300 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,350 | | |
| **Simple Average ($/kW)** | 6.183 | | |
| **Intercept** | 6.254 | 6.0376 | 2.02E-09 |
| **Slope** | -0.003 | -0.0768 | 9.39E-01 |
| **$R^2$** | 0.00000 | | |

### Figure D-5 — Gas/Oil CT Dataset – CAPEX for Between 100-MW and 300-MW Plant Size




Note: Age coefficient in above regression equation is not statistically significant.

## OPERATIONS & MAINTENANCE EXPENDITURES – BETWEEN 100 MW AND 300 MW

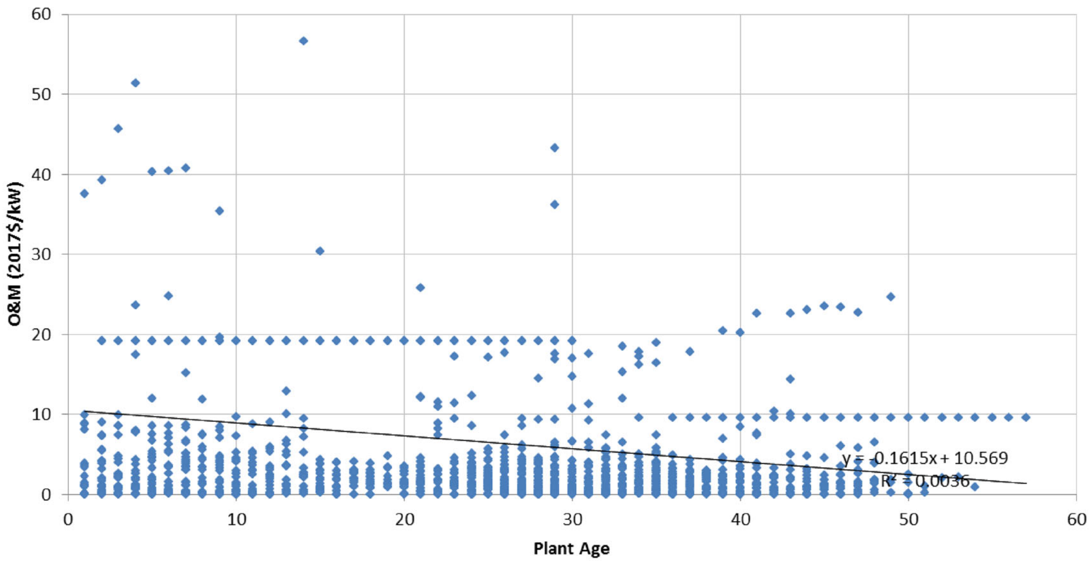
The results of the regression analysis of O&M spending for gas/oil CT plants between 100 MW and 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.023, which is less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 $/kW-year = 10.569 + (-0.162 × age)**

### Table D-6 — Regression Statistics – CT O&M 100 MW to 300 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,416 | | |
| **Simple Average ($/kW)** | 6.430 | | |
| **Intercept** | 10.569 | 5.1759 | 2.59E-07 |
| **Slope** | -0.162 | -2.2723 | 2.32E-02 |
| **$R^2$** | 0.00364 | | |

**Figure D-6 — Gas/Oil CT Dataset – O&M for Between 100-MW and 300-MW Plant Size**




Note: Sequential data points with identical values are forecasted values for the same plant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **100 MW - 300 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 9.97 | 5.18 | 3.24 | **6.43** | 442 | 794 | 180 | **1,416** |
| Net Total Capex - 2017 $/kW | 6.32 | 6.07 | 6.38 | **6.18** | 407 | 762 | 181 | **1,350** |
| Net Total O&M and Capex - 2017 $/kW | 15.14 | 9.09 | 9.66 | **10.98** | 402 | 759 | 180 | **1,341** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

## CAPITAL EXPENDITURES – GREATER THAN 300 MW

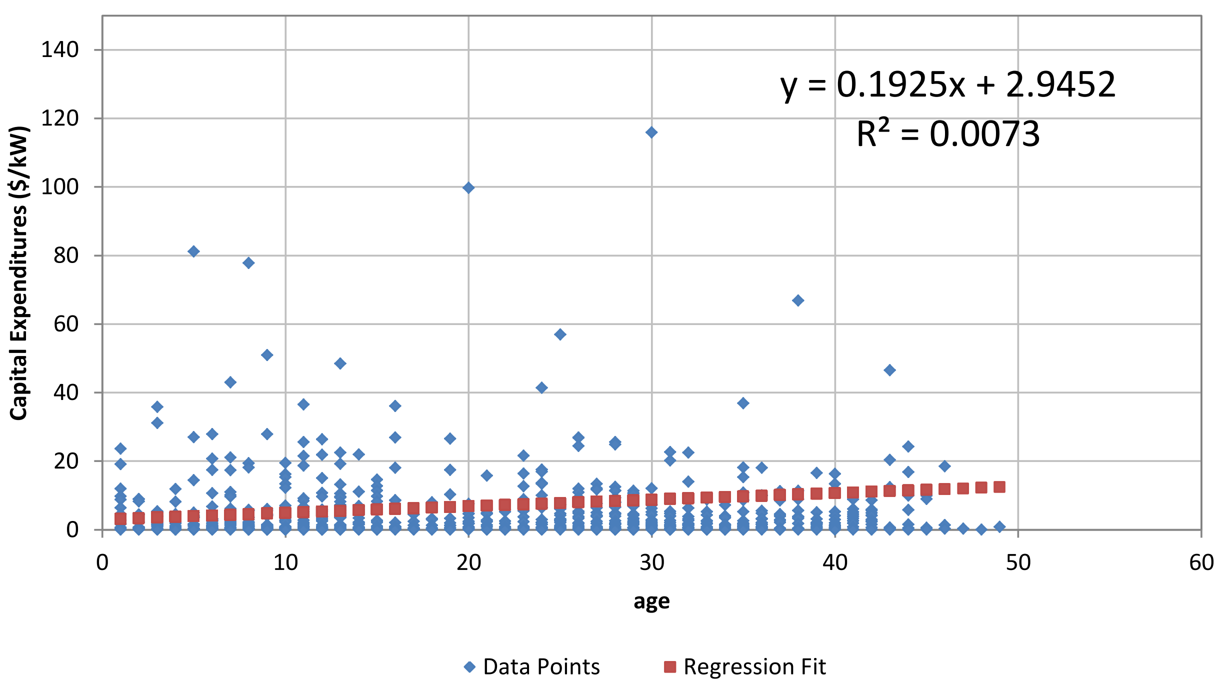
The results of the regression analysis of CAPEX spending for gas/oil CT plants greater than 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.010, which is less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

| **Annual CAPEX spending in 2017 \$/kW-year = 2.945 + (0.193 × age)** |
|---|

### Table D-7 — Regression Statistics – CT CAPEX > 300 MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 909 | | |
| **Simple Average (\$/kW)** | 6.952 | | |
| **Intercept** | 2.945 | 1.6382 | 1.017E-01 |
| **Slope** | 0.193 | 2.5842 | 0.010 |
| **$R^2$** | 0.00731 | | |

### Figure D-7 — Gas/Oil CT Dataset – CAPEX for Greater than 300-MW Plant Size



## OPERATIONS & MAINTENANCE EXPENDITURES – GREATER THAN 300 MW

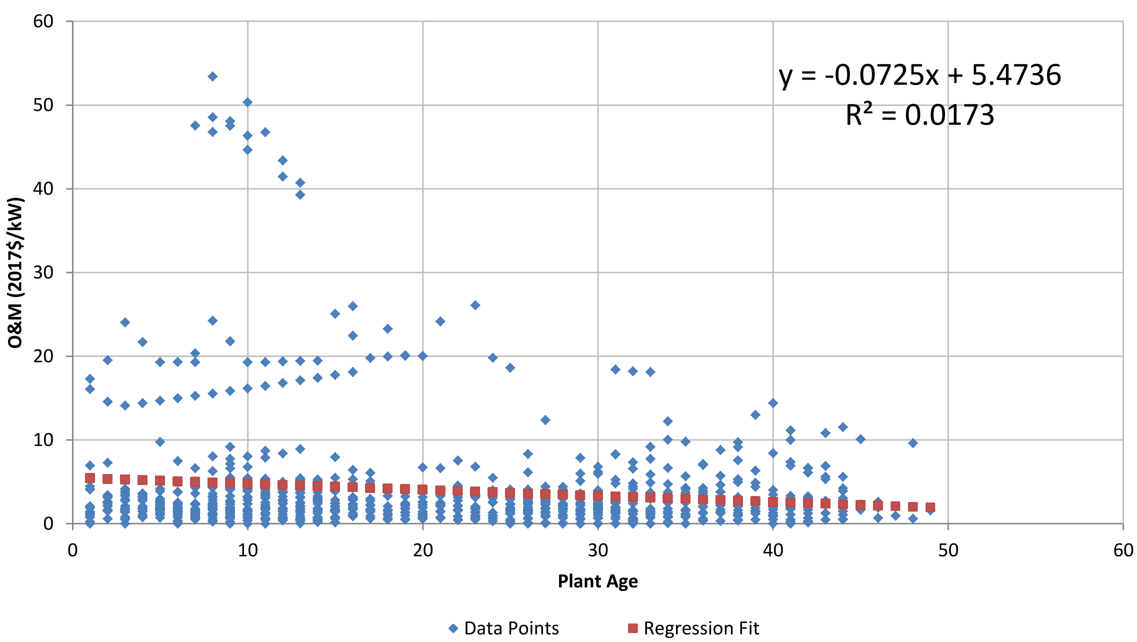
The results of the regression analysis of O&M spending for CT plants greater than 300 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 $/kW-year = 5.474 + (-0.072 × age)**

### Table D-8 — Regression Statistics – CT O&M > 300 MW

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 938 | | |
| **Simple Average ($/kW)** | 3.994 | | |
| **Intercept** | 5.474 | 12.8980 | 3.75E-35 |
| **Slope** | -0.072 | -4.0612 | 5.29E-05 |
| **$R^2$** | 0.01732 | | |

### Figure D-8 — Gas/Oil CT Dataset – O&M for Greater than 300-MW Plant Size




The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **> 300 MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 5.03 | 2.78 | 3.46 | **3.99** | 488 | 396 | 54 | **938** |
| Net Total Capex - 2017 $/kW | 5.26 | 7.58 | 16.50 | **6.95** | 457 | 397 | 55 | **909** |
| Net Total O&M and Capex - 2017 $/kW | 9.30 | 10.38 | 20.11 | **10.42** | 451 | 396 | 54 | **901** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing gas/oil CT plants are described in Section 6.

# Appendix E. Regression Analysis – Conventional Hydroelectric

## CAPITAL EXPENDITURES – ALL PLANT SIZES

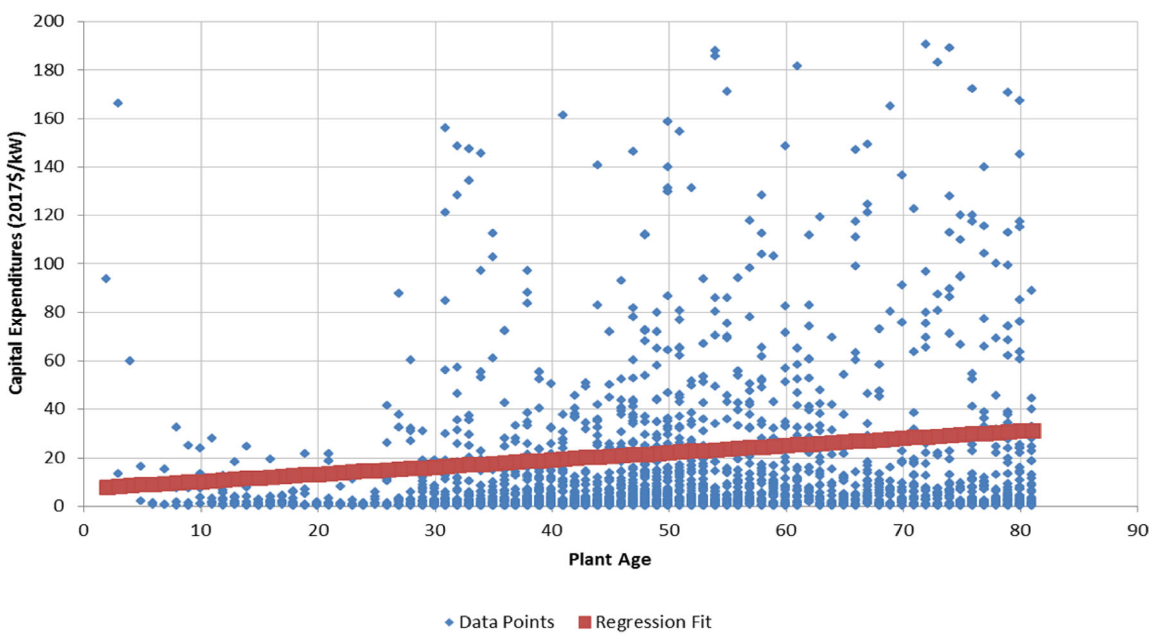
The results of the linear regression analysis of CAPEX spending for conventional hydroelectric plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, CAPEX spending for this dataset may be estimated by the regression equation:

**Annual CAPEX spending in 2017 $/kW-year = 7.269 + (0.296 × age)**

### Table E-1 — Regression Statistics – Hydroelectric CAPEX for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 2180 | | |
| **Simple Average ($/kW)** | 21.999 | | |
| **Intercept** | 7.269 | 1.4681 | 1.42E-01 |
| **Slope** | 0.296 | 3.1441 | 1.69E-03 |
| **$R^2$** | 0.00452 | | |

### Figure E-1 — Conventional Hydroelectric Dataset – CAPEX for All MW Plant Sizes



## OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

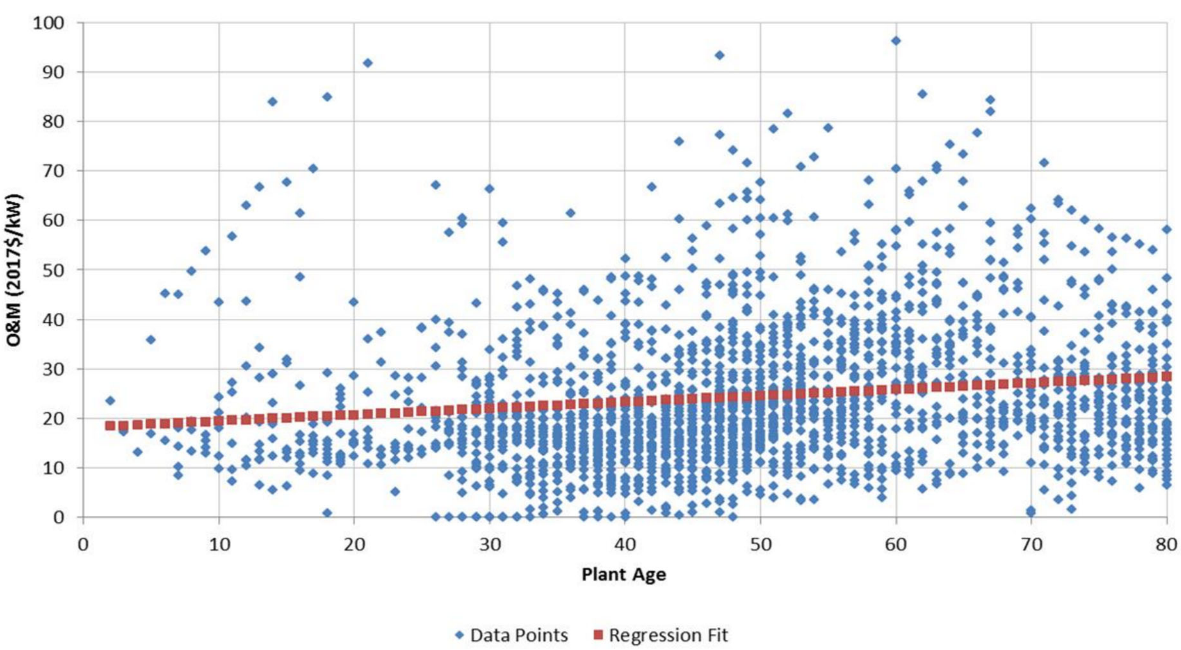
The results of the linear regression analysis of O&M spending for conventional hydroelectric plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for this dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 \$/kW-year = 22.360 + (0.073 × age)**

### Table E-2 — Regression Statistics – Hydroelectric O&M for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 1,272 | | |
| **Simple Average (\$/kW)** | 24.473 | | |
| **Intercept** | 22.360 | 13.7360 | 3.92E-40 |
| **Slope** | 0.073 | 2.5053 | 1.24E-02 |
| **$R^2$** | 0.00492 | | |

### Figure E-2 — Conventional Hydroelectric – O&M for All MW Plant Sizes



# Appendix F. Regression Analysis – Pumped Hydroelectric Storage

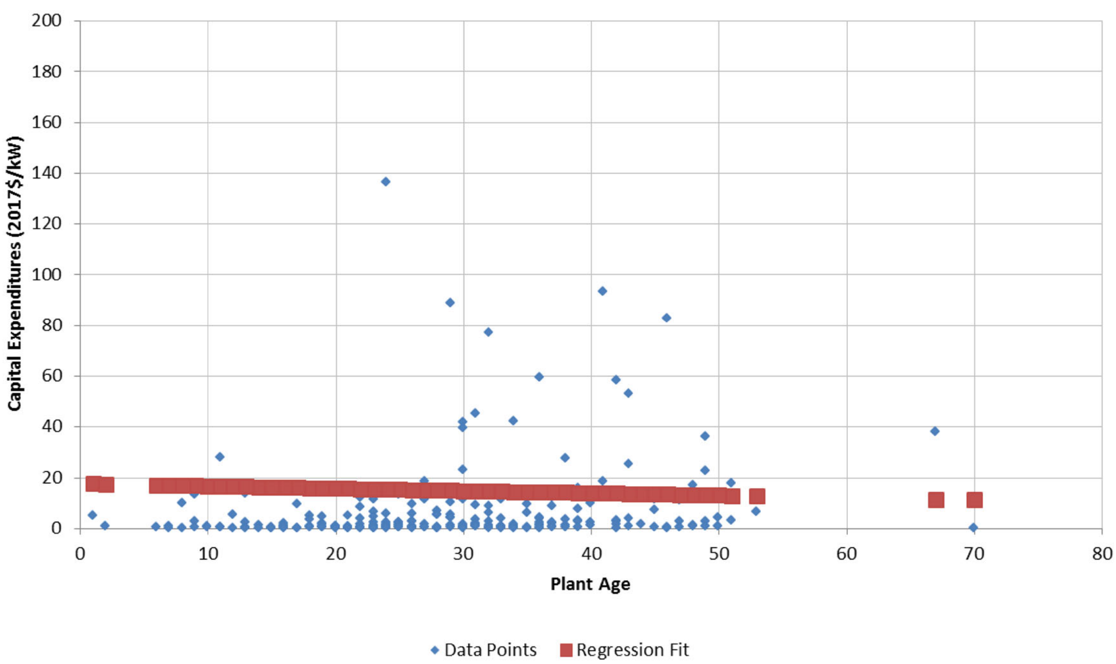
## CAPITAL EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of CAPEX spending for pumped hydroelectric storage plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). The dataset was not divided by unit capacity due to the limited number of data points.

### Table F-1 — Regression Statistics – Pumped Hydroelectric CAPEX for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 227 | | |
| **Simple Average ($/kW)** | 11.398 | | |
| **Intercept** | -6.907 | -0.4501 | 6.53E-01 |
| **Slope** | 0.743 | 1.2723 | 2.06E-01 |
| **$R^2$** | 0.01278 | | |

### Figure F-1 — Pumped Hydroelectric Dataset – CAPEX for All MW Plant Sizes




Note: Age coefficient in above regression equation is not statistically significant.

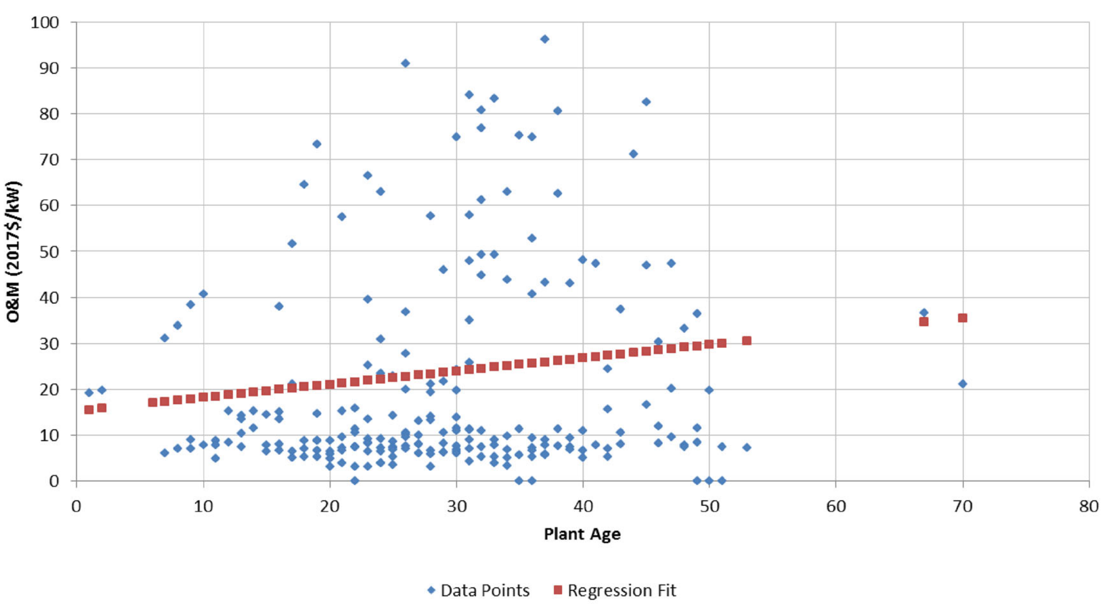
## OPERATIONS & MAINTENANCE EXPENDITURES – ALL PLANT SIZES

The results of the linear regression analysis of O&M spending for pumped hydroelectric storage plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages). The dataset was not divided by unit capacity due to the limited number of data points.

### Table F-2 — Regression Statistics – Pumped Hydroelectric O&M for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 226 | | |
| **Simple Average ($/kW)** | 23.634 | | |
| **Intercept** | 15.296 | 2.9021 | 4.08E-03 |
| **Slope** | 0.288 | 1.7010 | 9.03E-02 |
| **$R^2$** | 0.01275 | | |

### Figure F-2 — Pumped Hydroelectric – O&M for All Plant MW Sizes




Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each 20-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

| | Average $/kW (years 1 - 20) = | Average $/kW (years 21 - 40) = | Average $/kW (years 41 - 80) = | **Average $/kW (all years) =** | Data Points (years 1 - 20) = | Data Points (years 21 - 40) = | Data Points (years 41 - 80) = | **Data Points (all years) =** |
|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | |
| Net Total O&M- 2017 $/kW | 18.97 | 23.41 | 31.00 | **23.63** | 50 | 140 | 36 | **226** |
| Net Total Capex - 2017 $/kW | 22.94 | 11.93 | 14.92 | **14.83** | 50 | 141 | 36 | **227** |
| Net Total O&M and Capex - 2017 $/kW | 41.91 | 35.34 | 45.92 | **38.46** | -- | -- | -- | -- |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing pumped hydroelectric storage plants are described in Section 8.

# Appendix G. Regression Analysis – Solar Photovoltaic

## CAPITAL EXPENDITURES

Annual CAPEX, labeled in FERC Form 1 as TCP, are broken down into subcategories, including:

- Land & Land Rights
- Structures & Improvements
- Reservoirs, Dams & Waterways
- Water Wheels
- Turbines & Generators
- Accessory Electric Equipment
- Equipment
- Asset Retirement Costs
- Roads, and Railroads & Bridges

These subcategories are based on traditional power generation technologies and have minimal applicability to solar PV. Expected CAPEX for solar PV, such as inverter replacement and repair or module replacement, are clearly not applicable to any of the categories listed in FERC Form 1.

In the FERC Form 1 data, only 10 of the solar PV sites had a breakdown of TCP into the above subcategories, with even fewer providing such a breakdown for more than one year. As discussed in Section 9, the year-over-year change in TCP is the sole source of annual CAPEX information in FERC Form 1. Of this data, Sargent & Lundy determined that a significant portion of it needed to be filtered out due to the following reasons:

- A negative change in the TCP between two consecutive years
- A change in the capacity of the plant greater than 20%
- A significant increase in TCP without a capacity increase
- Large unexplained fluctuations (e.g., negative to positive) in TCP from year to year
- Large gaps in annual data

After filtering out clearly suspect data, about one-third of the remaining data was for plants having only three years of data or less. In addition, many of the plants reported no changes in TCP, suggesting that most annual expenditures at those sites were being reported as O&M rather than being capitalized.

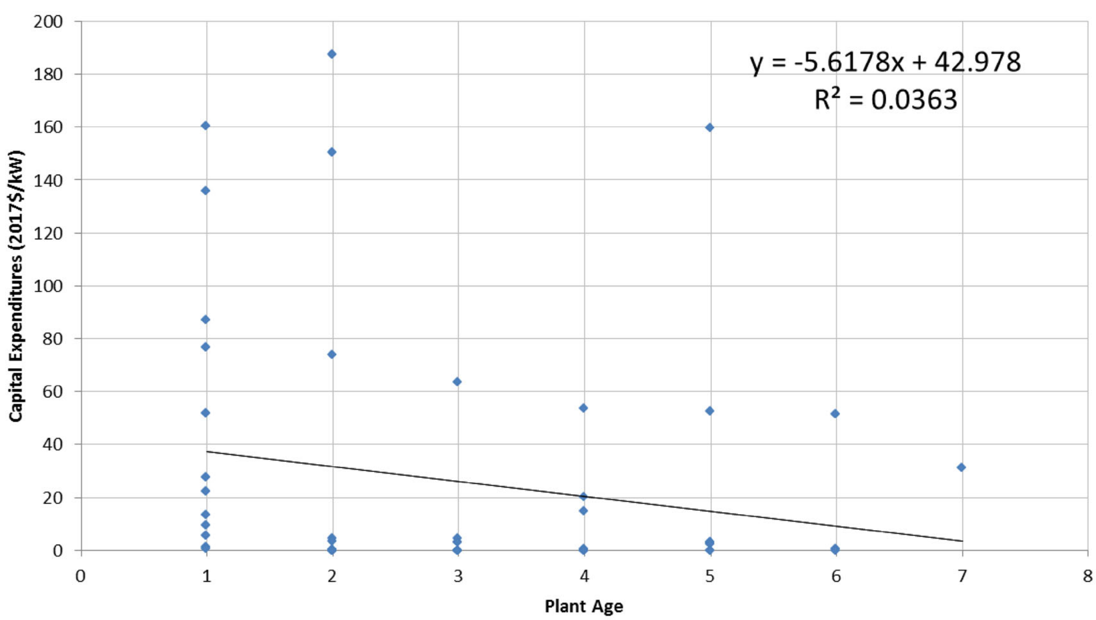
Thus, Sargent & Lundy had to rely on a limited dataset for solar PV consisting of 15 sites. The average change in TCP for these sites was approximately $26/kW-year. Based on the available FERC Form 1 information, it cannot be determined whether this change in TCP was due to typical CAPEX for solar PV, such as inverter or module replacement, or other factors.

The results of the linear regression analysis of CAPEX spending for solar PV plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient ("slope") is 0.16, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). In addition, as indicated in the table below, there are a relatively small number of data points for CAPEX (less than 60 points). The average CAPEX across all years is approximately $26/kW-year (2017 dollars).

**Table G-1 — Regression Statistics – Solar PV CAPEX for All MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 57 | | |
| **Simple Average ($/kW)** | 26.026 | | |
| **Intercept** | 42.978 | 3.2248 | 2.12E-03 |
| **Slope** | -5.618 | -1.4387 | 1.56E-01 |
| **$R^2$** | 0.03627 | | |

**Figure G-1 — Solar PV Dataset – CAPEX for All MW Plant Sizes**




Note: Age coefficient in above regression equation is not statistically significant.

## OPERATIONS & MAINTENANCE EXPENDITURES

Solar PV O&M activities include a variety of work scopes, including administrative work, monitoring, cleaning, preventative maintenance, and corrective maintenance. Some specific examples of O&M activities may include cleaning modules, monitoring system voltage and current, inspecting and cleaning electrical equipment, inspecting modules for damage, inspecting mounting systems, and checking invertor settings. The cost of O&M is dependent on several factors, including the number of components, the type of system (e.g., roof, tracking, ground mount, fixed, etc.), warranty coverage, and location. Environmental conditions, such as hail, sand/dust, snow, salt in air, high winds, etc., also play a significant role in O&M costs. For these reasons, a higher level of variation is expected when compared to traditional generating technologies.

The total production cost, which is the sum of the total operating expense and total maintenance expense, was reported for slightly over half of the sites. Of the sites reporting, several sites only reported this data in certain years, leaving gaps in the data. Subcategories for operating costs and maintenance cost were provided in the FERC Form 1 data, but rarely was the reported data broken into subcategories.

Sargent & Lundy organized the FERC Form 1 data into two presentation formats. In the first format, the annual O&M cost was averaged across all years of the reported data to obtain the average annual O&M cost per plant. This resulted in approximately 60 data points. In the second format, the annual O&M cost was averaged across each year of operation. This resulted in approximately 200 data points. The average O&M cost results are not equal between the two presentation formats. Table G-2 provides a simple example of these differing results, using FERC Form 1 O&M data from three plants.

**Table G-2 — Example of Calculation Method Differences**

| | O&M Cost ($/kW-year) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Age (Years) | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | Plant Average |
| Example Plant 1 | 127.8 | 0.0 | 0.1 | 0.0 | - | - | - | - | - | - | - | - | - | - | - | 32.0 |
| Example Plant 2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Example Plant 3 | 32.2 | 15.3 | 24.8 | - | - | - | - | - | - | - | - | - | - | - | - | 24.1 |

| | |
|---|---|
| Example Average (All Data Points) | 9.1 |
| Example Average (of Plant Averages) | 18.7 |

In the example above, a single plant with more data points is able to sway the average O&M cost across the three plants. The values calculated below are based on averaged data points (i.e., a data point is the average annual O&M cost across the reported data for a given plant).

Figure G-2 and Figure G-3 show the average site O&M cost, expressed in $/MWh, for sites with a capacity less than 5 MW and greater than 5 MW, respectively. In general, these figures show a high level of variability across sites, with smaller sites having a higher O&M cost per MWh produced. Several data points were for sites having very low capacity factors (less than 5%), which also results in higher O&M costs per MWh. For the sites greater than 5 MW, the average O&M cost was $8.5/MWh. When expressed on the basis of cost per kW of capacity (see Figure G-4 and Figure G-5), the average O&M for sites greater than 5 MW was $15/kW-year.

**Figure G-2 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (< 5 MW)**

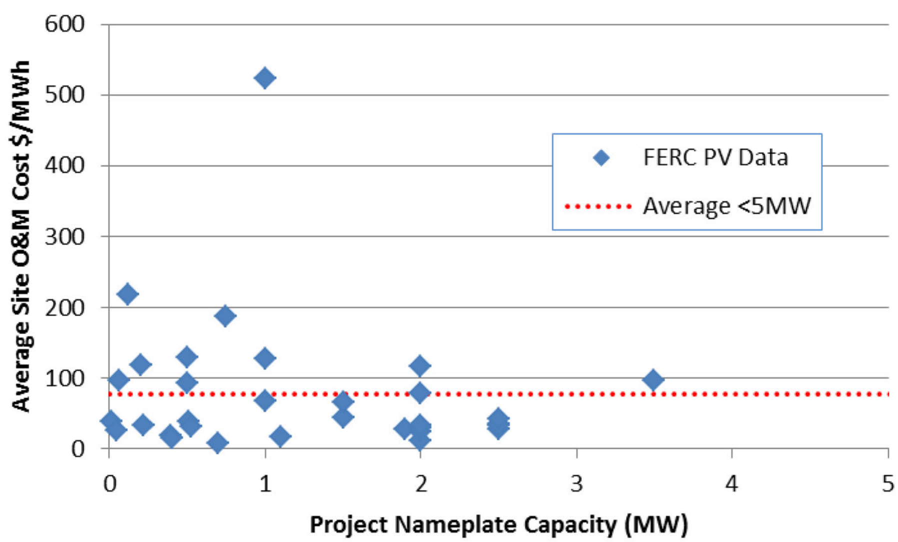


**Figure G-3 — Average Site O&M Cost per MWh Generated vs. Project Nameplate Capacity (> 5 MW)**

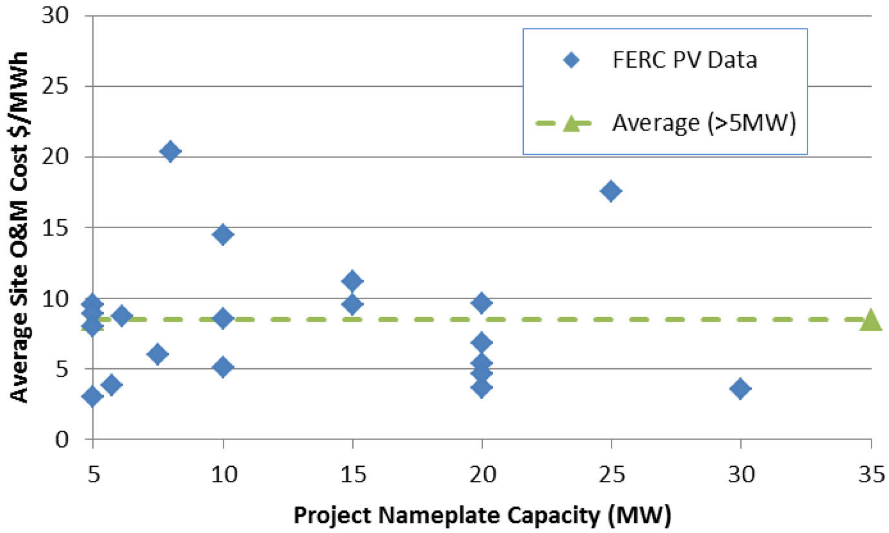



**Figure G-4 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (< 5 MW)**

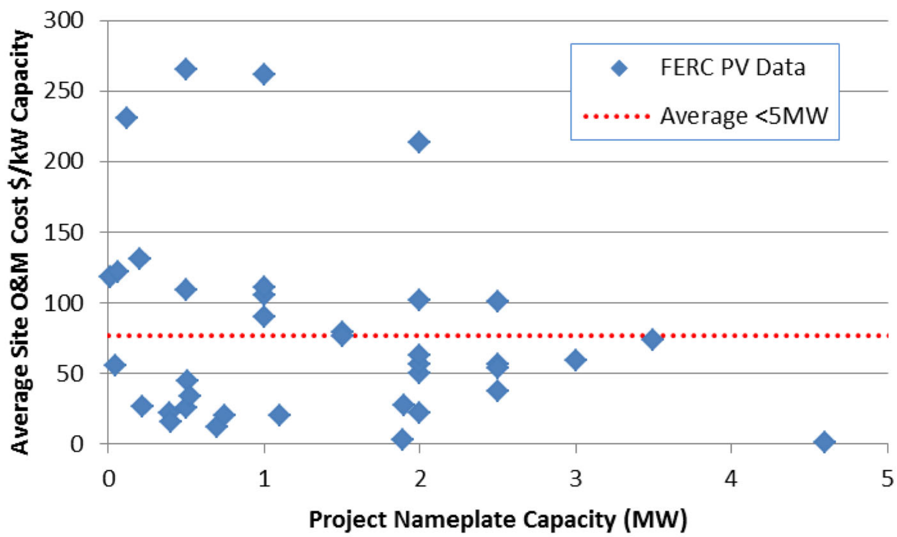
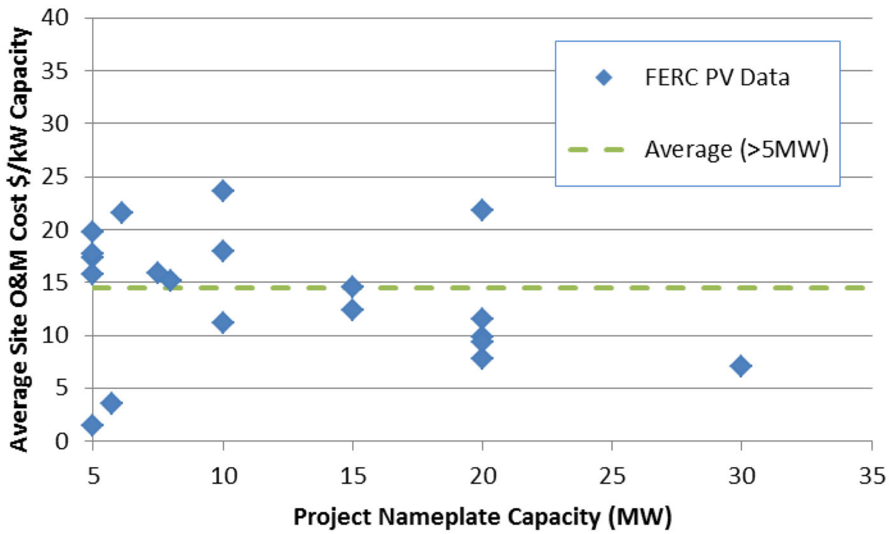
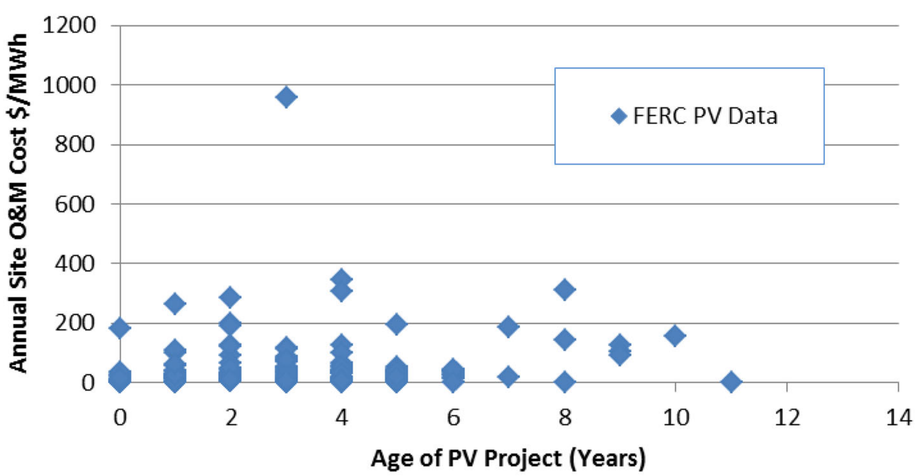


**Figure G-5 — Average Site O&M Cost per kW-Year Capacity vs. Project Nameplate Capacity (> 5 MW)**

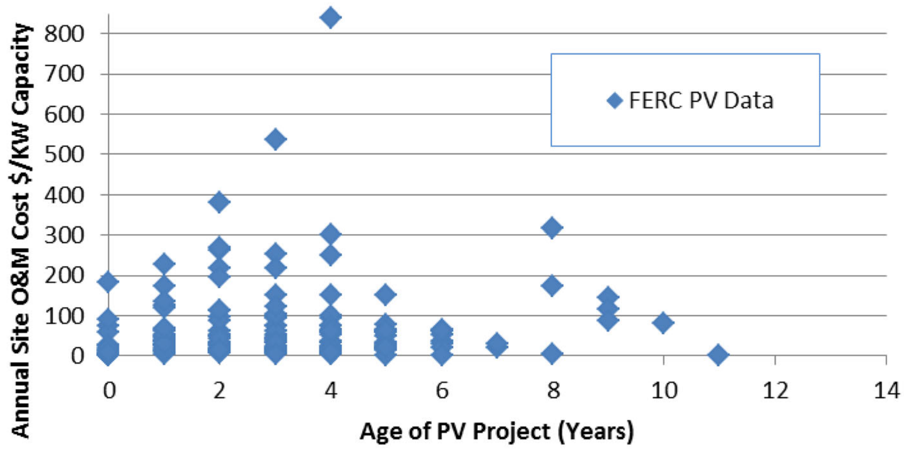



The figures below show the annual site O&M cost (in $/MWh and $/kW-year) versus the age of the project. In general, little correlation can be seen between age and O&M cost.

**Figure G-6 — Annual Site O&M Cost per MWh vs. Age of Project**



### Figure G-7 — Annual Site O&M Cost per kW-Year Capacity vs. Age of Project




Sargent & Lundy compiled O&M data from other sources in Table G-3 below for comparison against the FERC data. In general, the O&M costs in $/kW-year capacity are in the same range as the FERC data for sites over 5-MW capacity.

### Table G-3 — Summary of Industry O&M Cost Data for Solar PV

| O&M Cost Sources | O&M Cost $/kW-yr | Notes | Report Source Data Year |
|---|---|---|---|
| NREL & Sunshot | 15 | Fixed | 2015 |
| NREL & Sunshot | 18 | Single-Axis Tracking | 2015 |
| Sunshot + NREL | 20.5 | Good O&M | 2016 |
| Sunshot + NREL | 25.0 | Optimal O&M | 2016 |
| IRENA Power to Change | 10 | Minimum | 2015 |
| IRENA Power to Change | 18 | Maximum | 2015 |
| Utility Scale Solar | 17 | Overall | 2014 |
| Utility Scale Solar 2016 | 7 | Minimum | 2016 |
| Utility Scale Solar 2016 | 27 | Maximum | 2016 |
| Utility Scale Solar 2016 | 18 | Mean | 2016 |
| NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017 | 15.4 | Fixed LCOE Assumption | 2017 |
| NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018 | 18.5 | SAT LCOE Assumption | 2017 |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing solar PV plants are described in Section 9.

# Appendix H. Regression Analysis – Solar Thermal

There are no solar thermal power plants that report operating data in FERC Form 1. Industry-wide, there are a limited number of solar thermal projects; a majority of which have been constructed within the last 10 years—the exception being small test facilities and the Solar Energy Generating Systems (SEGS) plants built in the 1980s.

# Appendix I. Regression Analysis – Geothermal

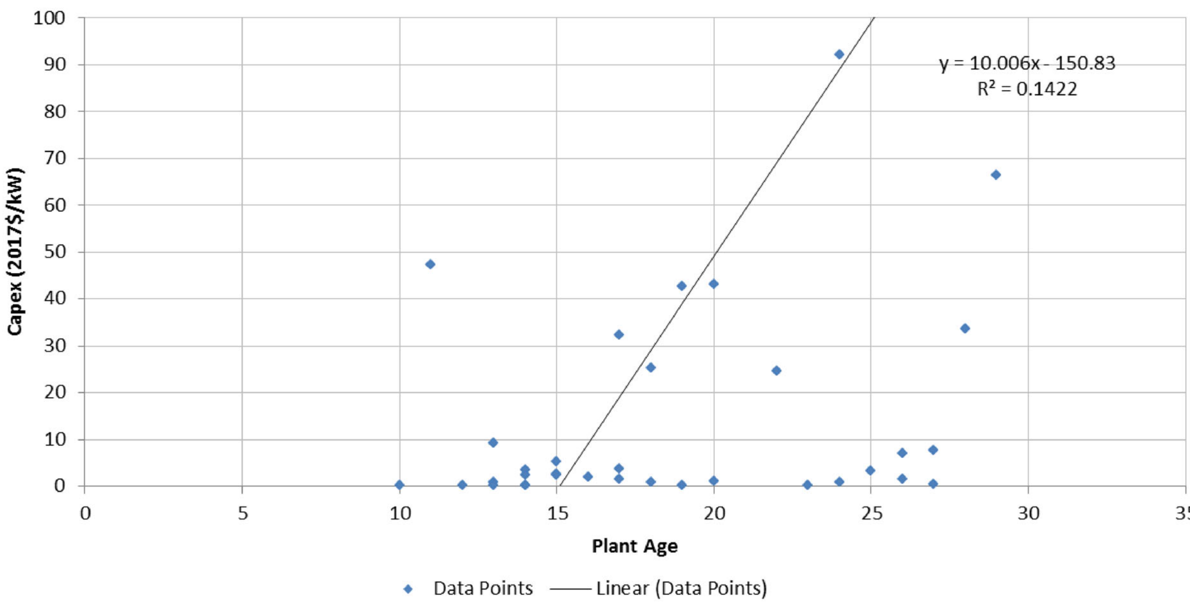
## CAPITAL EXPENDITURES

The results of the linear regression analysis of CAPEX spending for geothermal plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Although the p-value is less than 0.05, the dataset is inconclusive because the intercept is negative due to no plants reporting data between ages and 0 and 10.

### Table I-1 — Regression Statistics – Geothermal CAPEX for All MW

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 36 | | |
| **Simple Average ($/kW)** | 40.948 | | |
| **Intercept** | -150.830 | -1.7907 | 8.23E-02 |
| **Slope** | 10.006 | 2.3736 | 2.34E-02 |
| **$R^2$** | 0.14215 | | |

### Figure I-1 — Geothermal Dataset – CAPEX for All MW Plant Sizes



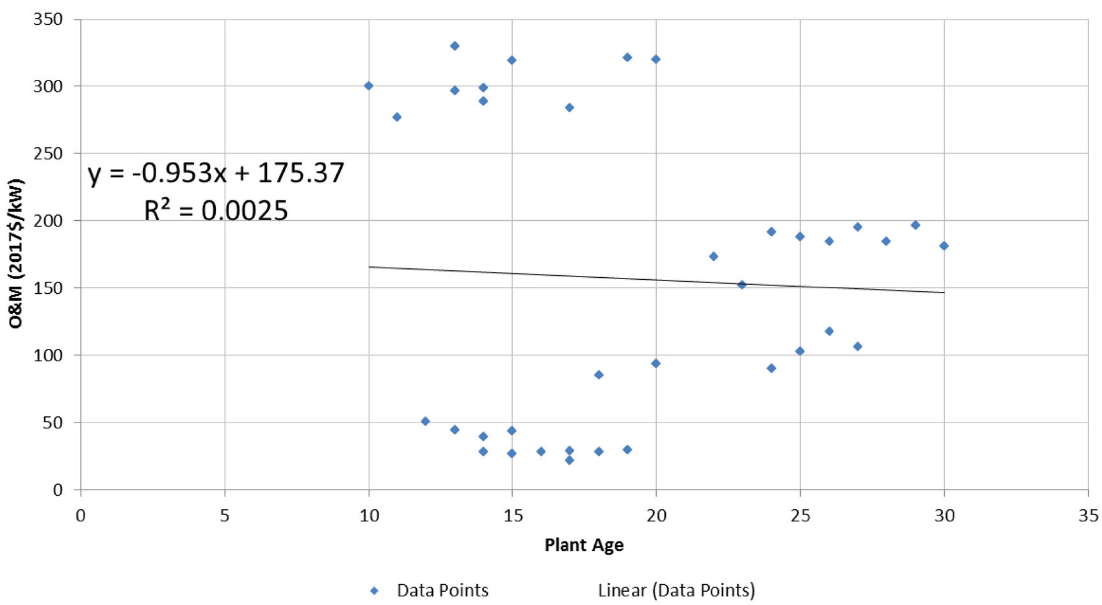
## OPERATIONS & MAINTENANCE EXPENDITURES

The results of the linear regression analysis of O&M spending for geothermal plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.071, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of O&M spending (on a linear trend across all plant ages).

### Table I-2 — Regression Statistics – Geothermal O&M for All MW

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 36 | | |
| **Simple Average ($/kW)** | 157.103 | | |
| **Intercept** | 175.369 | 2.6984 | 1.08E-02 |
| **Slope** | -0.953 | -0.2930 | 7.71E-01 |
| **$R^2$** | 0.00252 | | |

### Figure I-2 — Geothermal Dataset – O&M for All MW Plant Sizes




Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

## Table I-3 — Geothermal All MW Summary of Results

| | Average $/kW-yr (Years 1-5) | Average $/kW-yr (Years 6-10) | Average $/kW-yr (Years 11-15) | Average $/kW-yr (Years 16-20) | Average $/kW-yr (Years 21-25) | Average $/kW-yr (Years 26-30) | Average $/kW-yr (All Years) | Data Points (Years 1-5) | Data Points (Years 6-10) | Data Points (Years 11-15) | Data Points (Years 16-20) | Data Points (Years 21-25) | Data Points (Years 26-30) | Data Points (All Years) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | | | | | | | |
| Net Total O&M – 2017 $/kW-yr | -- | 300.62 | 170.44 | 124.24 | 149.97 | 166.77 | **157.10** | -- | 1 | 12 | 10 | 6 | 7 | **36** |
| Net Total CAPEX – 2017 $/kW-yr | -- | -- | 72.05 | 30.16 | 27.64 | 114.45 | **40.94** | -- | 1 | 12 | 10 | 6 | 7 | **36** |

Starting with the initial analysis of CAPEX and O&M raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing geothermal plants are described in Section 11.

# Appendix J. Regression Analysis – Wind

# CAPITAL EXPENDITURES

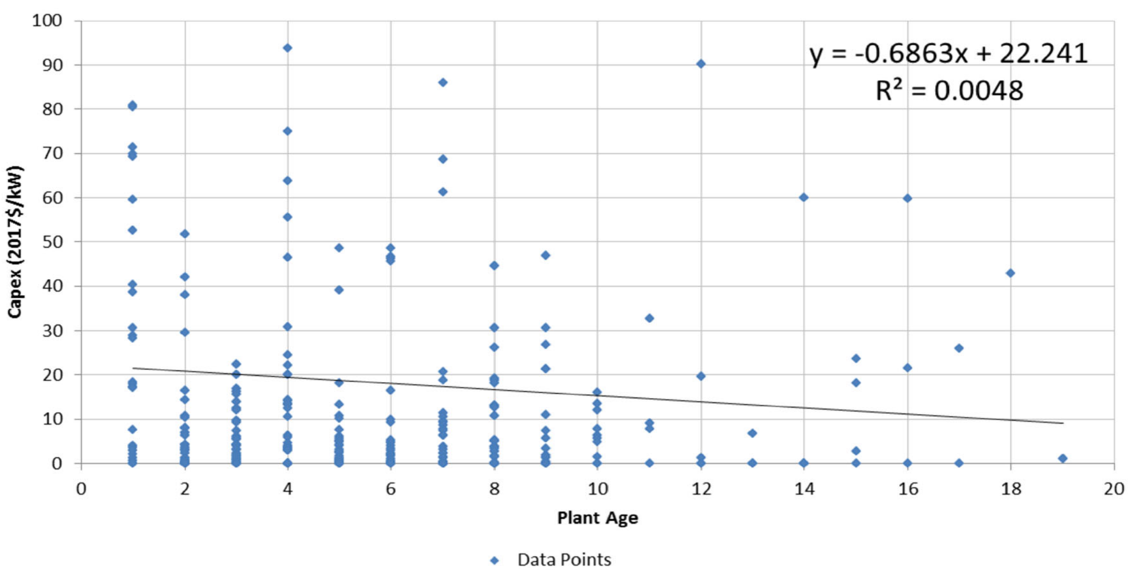
## *Full Dataset*

The results of the linear regression analysis of CAPEX spending for wind plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.224, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

**Table J-1 — Regression Statistics – Wind CAPEX for All MW**

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 310 | | |
| **Simple Average ($/kW)** | 18.285 | | |
| **Intercept** | 22.241 | 5.7807 | 1.82E-08 |
| **Slope** | -0.686 | -1.2194 | 2.24E-01 |
| **$R^2$** | 0.00480 | | |

**Figure J-1 — Wind Dataset – CAPEX for All MW Plant Sizes**




Note: Age coefficient in above regression equation is not statistically significant.

The simple average O&M and CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

### Table J-2 — Wind All MW Summary of Results

| | Average $/kW-yr (Years 1-5) | Average $/kW-yr (Years 6-10) | Average $/kW-yr (Years 11-15) | Average $/kW-yr (Years 16-20) | Average $/kW-yr (All Years) | Data Points (Years 1-5) | Data Points (Years 6-10) | Data Points (Years 11-15) | Data Points (Years 16-20) | Data Points (All Years) |
|---|---|---|---|---|---|---|---|---|---|---|
| **All MW, All Capacity Factors** | | | | | | | | | | |
| Net Total CAPEX – 2017 $/kW-yr | 21.06 | 10.97 | 32.62 | 21.60 | **18.29** | 168 | 112 | 23 | 7 | **310** |

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

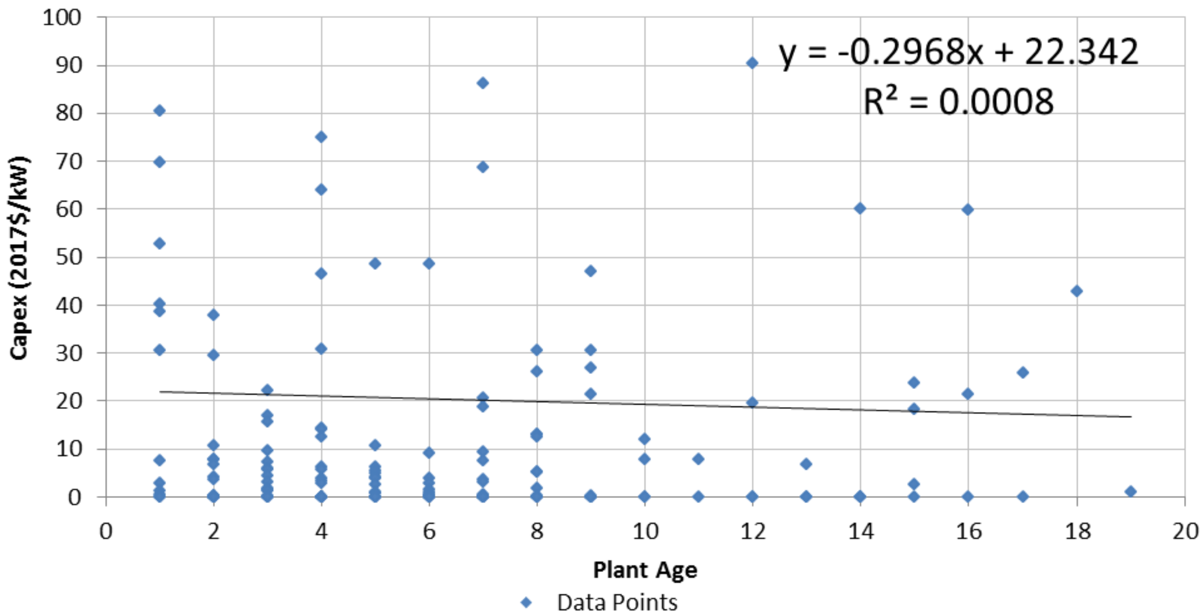
#### *0-100 MW*

The results of the linear regression analysis of CAPEX spending for wind plants between 0 MW and 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.706, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). Therefore, a more appropriate predictor of CAPEX spending for this dataset is a simple average by plant age band, as discussed in Section 12.

### Table J-3 — Regression Statistics – Wind CAPEX for 0-100 MW

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 174 | | |
| **Simple Average ($/kW)** | 20.483 | | |
| **Intercept** | 22.342 | 3.7750 | 2.20E-04 |
| **Slope** | -0.297 | -0.3779 | 7.06E-01 |
| **$R^2$** | 0.00083 | | |

### Figure J-2 — Wind Dataset – CAPEX for 0-100-MW Plant Sizes




Note: Age coefficient in above regression equation is not statistically significant.

The simple average CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

### Table J-4 — Wind < 100-MW Summary of Results

| | Average $/kW-yr (Years 1-5) | Average $/kW-yr (Years 6-10) | Average $/kW-yr (Years 11-15) | Average $/kW-yr (Years 16-20) | Average $/kW-yr (All Years) | Data Points (Years 1-5) | Data Points (Years 6-10) | Data Points (Years 11-15) | Data Points (Years 16-20) | Data Points (All Years) |
|---|---|---|---|---|---|---|---|---|---|---|
| **< 100 MW, All Capacity Factors** | | | | | | | | | | |
| Net Total CAPEX – 2017 $/kW-yr | 22.83 | 11.62 | 35.35 | 21.60 | **20.48** | 89 | 58 | 20 | 7 | **174** |

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

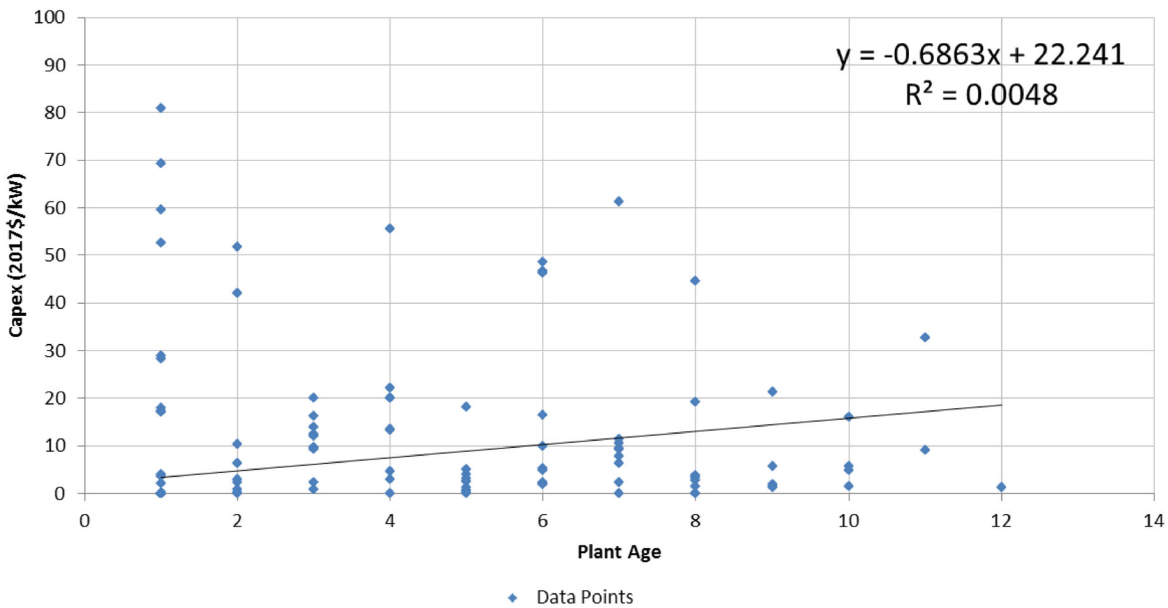
### *100-200 MW*

The results of the linear regression analysis of CAPEX spending for wind plants between 100 MW and 200 MW are summarized in the table below. Since the p-value for the age coefficient is 0.224, which is greater than 0.05, the dataset does not support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages).

**Table J-5 — Regression Statistics – Wind CAPEX for 100-200 MW**

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 310 | | |
| **Simple Average ($/kW)** | 16.935 | | |
| **Intercept** | 22.241 | 5.7807 | 1.82E-08 |
| **Slope** | -0.686 | -1.2194 | 2.24E-01 |
| **$R^2$** | 0.00480 | | |

**Figure J-3 — Wind Dataset – CAPEX for 100-200-MW Plant Sizes**




Note: Age coefficient in above regression equation is not statistically significant.

The simple average CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

**Table J-6 — Wind 100-200-MW Summary of Results**

| | Average \$/kW-yr (Years 1-5) | Average \$/kW-yr (Years 6-10) | Average \$/kW-yr (Years 11-15) | Average \$/kW-yr (Years 16-20) | Average \$/kW-yr (All Years) | Data Points (Years 1-5) | Data Points (Years 6-10) | Data Points (Years 11-15) | Data Points (Years 16-20) | Data Points (All Years) |
|---|---|---|---|---|---|---|---|---|---|---|
| **100 - 200 MW, All Capacity Factors** | | | | | | | | | | |
| Net Total CAPEX – 2017 \$/kW-yr | 20.36 | 12.20 | 14.41 | -- | **16.93** | 52 | 36 | 3 | -- | **91** |

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

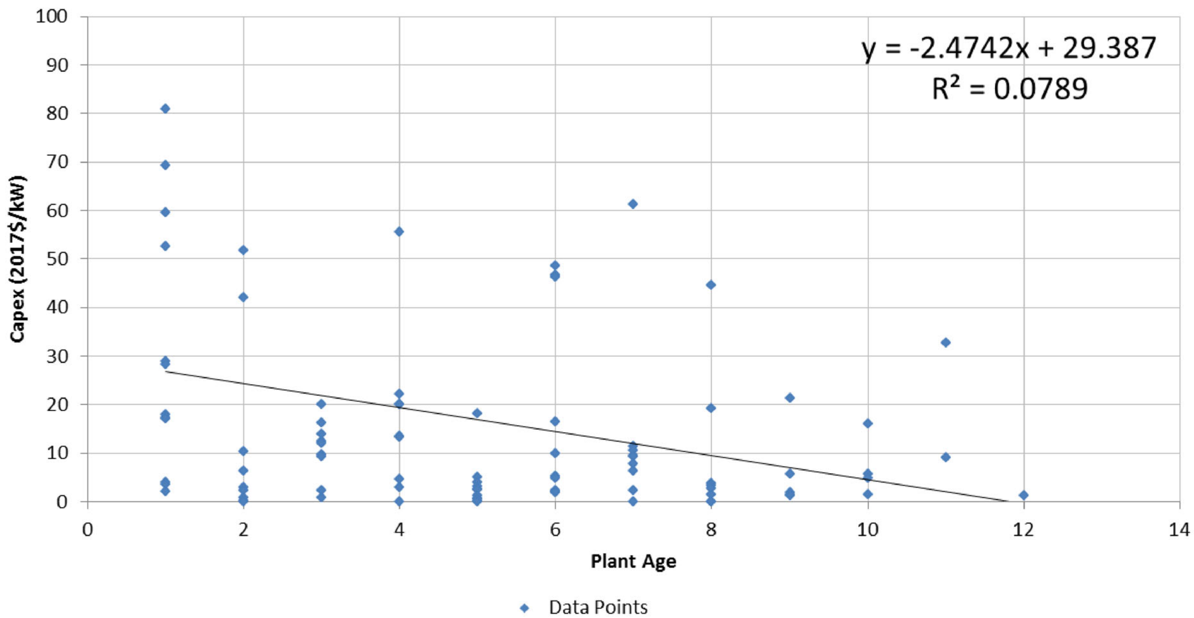
### *Greater than 200 MW*

The results of the linear regression analysis of CAPEX spending for wind plants greater than 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.006, which is less than 0.05, the dataset does support age as a statistically significant predictor of CAPEX spending (on a linear trend across all plant ages). However, a visual inspection of the data in the graph below shows that there are a limited number of data points over 10 years, which may be skewing the regression.

**Table J-7 — Regression Statistics – Wind CAPEX for Greater than 200 MW**

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 91 | | |
| **Simple Average (\$/kW)** | 16.935 | | |
| **Intercept** | 29.387 | 5.6538 | 1.87E-07 |
| **Slope** | -2.474 | -2.7612 | 6.99E-03 |
| **$R^2$** | 0.07891 | | |

### Figure J-4 — Wind Dataset – CAPEX for Greater than 200-MW Plant Sizes




The simple average CAPEX values for each five-year age band, expressed in constant 2017 $/kW-year, are summarized in the table below.

### Table J-8 — Wind Greater than 200-MW Summary of Results

| | Average $/kW-yr (Years 1-5) | Average $/kW-yr (Years 6-10) | Average $/kW-yr (All Years) | Data Points (Years 1-5) | Data Points (Years 6-10) | Data Points (All Years) |
|---|---|---|---|---|---|---|
| **> 200 MW, All Capacity Factors** | | | | | | |
| Net Total CAPEX – 2017 $/kW-yr | **16.61** | **8.65** | **13.48** | 31 | 20 | **51** |

Starting with the initial analysis of CAPEX raw data, as presented above, Sargent & Lundy developed recommended changes to the existing values used in the EMM. The recommended changes for existing wind plants are described in Section 12.

## OPERATIONS & MAINTENANCE EXPENDITURES

### *Full Dataset*

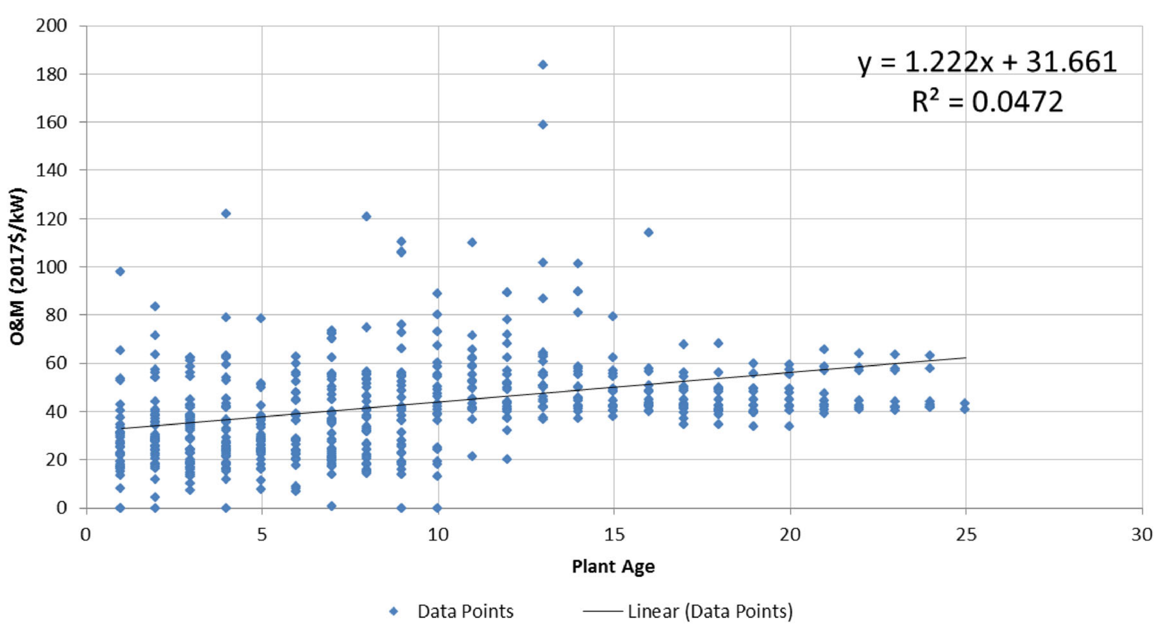
The results of the linear regression analysis of O&M spending for wind plants of all MW sizes (full dataset) are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 $/kW-year = 31.661 + (1.222 × age)**

**Table J-9 — Regression Statistics – Wind O&M for All MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 580 | | |
| **Simple Average ($/kW)** | 42.680 | | |
| **Intercept** | 31.661 | 12.7763 | 4.24E-33 |
| **Slope** | 1.222 | 5.3515 | 1.26E-07 |
| **$R^2$** | 0.04721 | | |

**Figure J-5 — Wind Dataset – O&M for All MW Plant Sizes**



### *0-100 MW*

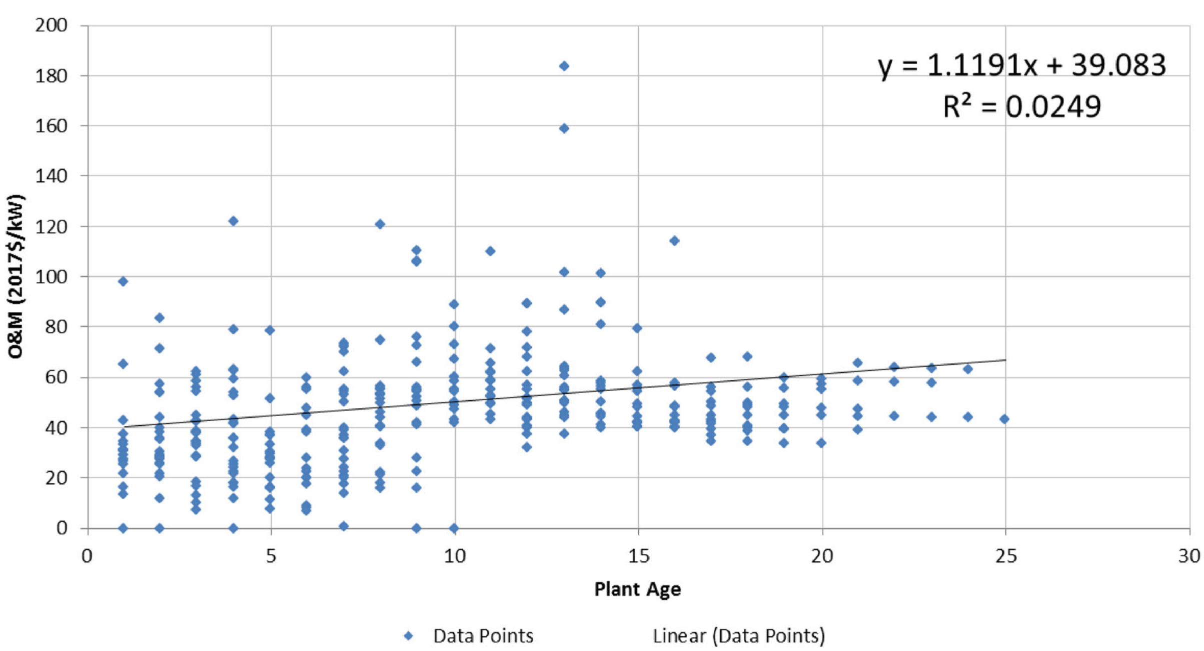
The results of the linear regression analysis of O&M spending for wind plants between 0 MW and 100 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is 0.003, which is less than 0.05, the dataset age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 $/kW-year = 39.083 + (1.119 × age)**

**Table J-10 — Regression Statistics – Wind O&M for 0-100 MW**

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 339 | | |
| **Simple Average ($/kW)** | 49.888 | | |
| **Intercept** | 39.083 | 9.0574 | 1.10E-17 |
| **Slope** | 1.119 | 2.9310 | 3.61E-03 |
| **$R^2$** | 0.02486 | | |

**Figure J-6 — Wind Dataset – O&M for 0-100-MW Plant Sizes**



### *100-200 MW*

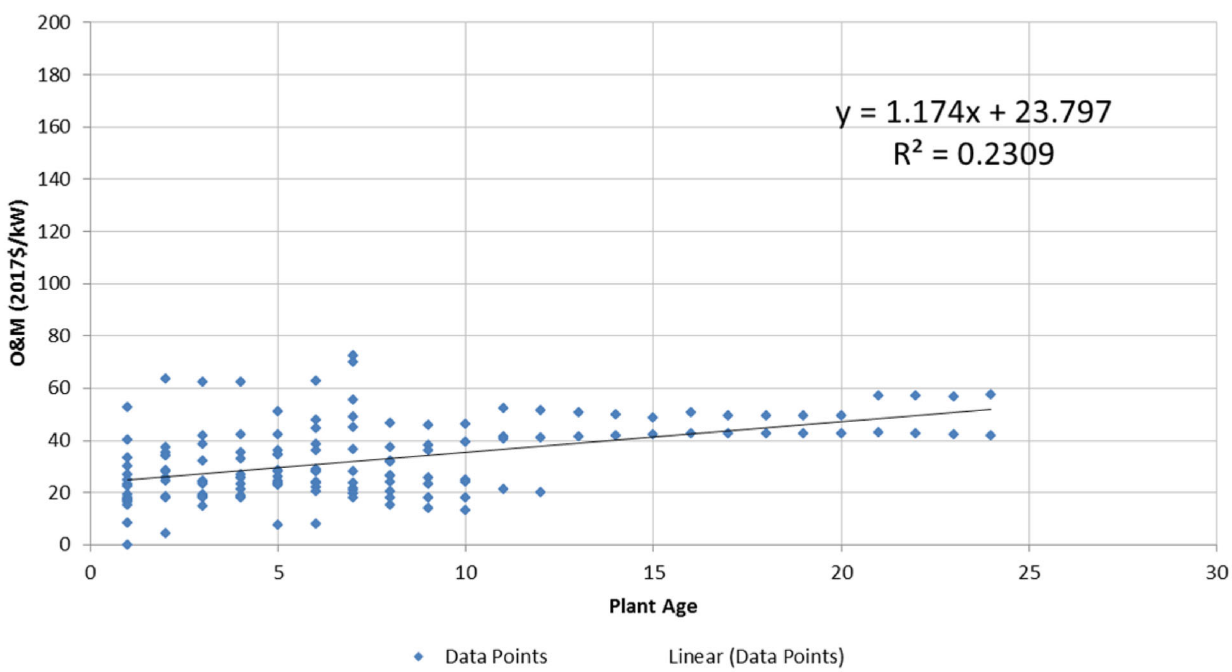
The results of the linear regression analysis of O&M spending for wind plants between 100 MW and 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 \$/kW-year = 23.797 + (1.174 × age)**

**Table J-11 — Regression Statistics – Wind O&M for 100-200 MW**

| | | *t Statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 147 | | |
| **Simple Average (\$/kW)** | 35.645 | | |
| **Intercept** | 23.797 | 14.1919 | 3.27E-29 |
| **Slope** | 1.174 | 6.5971 | 7.33E-10 |
| **$R^2$** | 0.23086 | | |

**Figure J-7 — Wind Dataset – O&M for 100-200-MW Plant Sizes**



### *Greater than 200 MW*

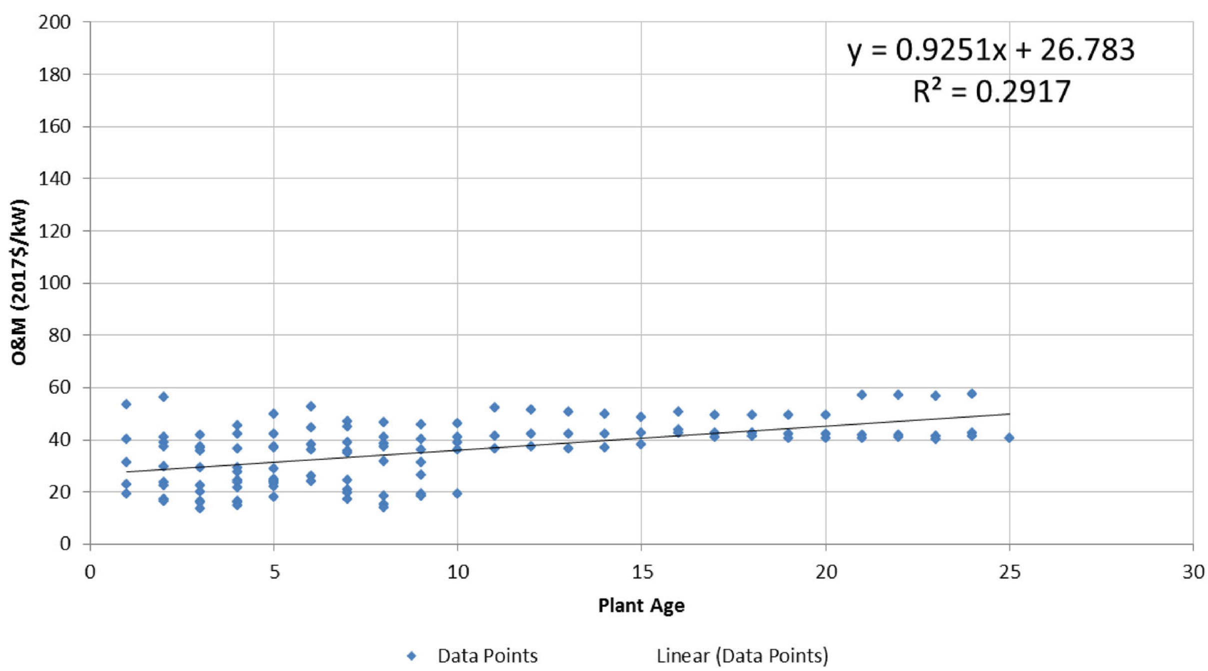
The results of the linear regression analysis of O&M spending for wind plants greater than 200 MW are summarized in the table below and plotted in the figure below. Since the p-value for the age coefficient is significantly less than 0.05, age is a statistically significant predictor of O&M spending (on a linear trend across all plant ages). Therefore, O&M spending for the dataset may be estimated by the regression equation:

**Annual O&M spending in 2017 \$/kW-year = 26.783 + (0.925 × age)**

**Table J-12 — Regression Statistics – Wind O&M Greater than 200 MW**

| | | *t statistic* | *p-value* |
|---|---|---|---|
| **Observations** | 124 | | |
| **Simple Average (\$/kW)** | 35.645 | | |
| **Intercept** | 26.783 | 17.5334 | 3.90E-35 |
| **Slope** | 0.925 | 7.0885 | 9.55E-11 |
| **$R^2$** | 0.29171 | | |

**Figure J-8 — Wind Dataset – O&M for Plant Sizes Greater than 200 MW**



# Grid of the Future:
# PJM's Regional Planning Perspective

PJM Planning Division

May 10, 2022

For Public Use

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## Contents

# 1. Executive Summary

Over the past decade, increasing focus by federal and state governments on climate change, energy independence and other policy areas continues to make clear the critical role of the transmission system. PJM is working to outline a vision and present a road map for the grid of the future by examining industry trends and drivers to assess the potential impacts on PJM's transmission planning process.

The grid of the future is not some far-distant idea but is here now. PJM, like other power grid operators across the U.S., has before it a robust, reliable transmission grid, but one upon which enhanced operational flexibility must continue to grow to ensure reliable power delivery 24/7 year-round.

## *Vision*

PJM's Regional Transmission Expansion Plan (RTEP) process continues to evolve, bringing into clearer focus a future grid driven by decarbonization, renewables, public policy, resource mix and new technologies. Achieving this future means enhancing operational flexibility and ensuring that reliability and resilience remain paramount.

## *Road Map*

This report outlines PJM's system planning road map to achieve its future grid vision by examining trends and drivers that are impacting the RTEP process. This initiative is part of a multi-year effort to implement PJM's corporate strategy as approved by the PJM Board to enable transition in a changing industry. The RTEP process component as discussed in this report builds on work completed as part of PJM's related renewable integration studies and papers emphasizing markets and operations.

PJM's road map encompasses four areas of focus as part of continuing efforts to enhance planning processes in preparation for the future grid.

**1 |** ***Transmission build-out scenario studies*** will be conducted in 2022 based on power-flow case alignment with PJM's renewable integration studies and by leveraging analytical work of the Offshore Wind Scenario Study Phase 1. This major planning effort considered not only offshore wind injection, but renewable resources to meet states' Renewable Portfolio Standard (RPS) objectives. As PJM continues its initiatives to enable a decarbonized grid, additional analysis will be undertaken beyond the offshore wind scenario studies to examine an accelerated renewable penetration case, including a more in-depth assessment of the impacts driven by greater building and transportation electrification.

**2 |** ***Targeted reliability studies*** will build on 2022 scenario study results to evaluate generation and transmission reliability attributes, such as reactive control, stability, system inertia and frequency control, and short-circuit impacts to ensure reliable operations.

**3 |** ***RTEP process enhancements*** will continue to evolve, including a number of key initiatives already underway: interconnection process reform, generator deliverability methodology improvement, Effective Load Carrying Capability methodology development, and implementation of probabilistic planning techniques.

**4 |** ***Regulatory policy impacts*** continue to inform new reliability criteria for extreme events, state electrification policies, interconnection process reform, state policy implementation, distributed energy resources (DER) expansion and FERC action on regional transmission planning per its recent ANOPR.[1] Going forward, PJM must continue to be engaged on policy discussions that will impact how it plans the transmission system through the ongoing changes.

The goal of this report is to ensure that PJM's future grid maintains the reliability and operational flexibility necessary to address key drivers that are changing the face of the industry. It builds on PJM's renewable integration study work and is informed by the work completed by other RTOs and other relevant industry entities.

## *Industry Trends and Drivers*

Planning's approach for this report was to examine the key industry trends driving future grid expansion: generation development, evolving load characteristics, emerging transmission technologies and resilience.

**Generation** – Addresses growing renewable resource trends for wind, solar and storage. These resources are typically variable and of limited output duration. PJM's generation shift is also driven by deactivation of conventional generation resources powered by coal, natural gas and nuclear, given their "at-risk" vulnerability arising out of economics and decarbonization public policy.

**Load** – Discusses two key dimensions of future load trends: (1) DER, which explore unique challenges for integrating a growing amount of generation connected at the distribution level and may include retail and wholesale market participation; and (2) discussion of load trends driven by the impact of electrification of transportation and building heating.

**Emerging Technologies** – Explores the emerging technologies that may play a role in managing congestion and solving reliability criteria violations associated with integrating significant amounts of renewable resources. Such technologies may reduce the need for, or mitigate impacts of, new greenfield transmission lines and the attendant siting approval and permitting challenges.

**Resilience** – Considers criteria needed to address more extreme system events. These warrant greater attention for a transmission grid with: (1) higher penetration of variable and duration-limited resources reliant on sun and wind to operate; and (2) an end-use sector with growing reliance on electrification.

### Generation Shift

While PJM state renewable goals differ in scope, timing, resource specificity, means of implementation, and mandatory versus voluntary, most state jurisdictions in the region PJM serves have some level of renewable resource or clean energy targets. Meeting these targets will include terrestrial wind, offshore wind and solar resource development as well as storage. In PJM's interconnection queue, renewables and storage account for over 90% of requests. Most of the recent queue requests for grid interconnection throughout the region PJM serves are from inverter-based solar generation resources. Previously, solar projects were smaller in size and limited to a handful of areas. Now, the size of individual projects can be on the order of hundreds of megawatts, driven by states' RPS goals, and are locating in every PJM transmission zone.

[1] On Oct. 12, 2021, PJM filed its initial comments in FERC's Advanced Notice of Proposed Rulemaking (ANOPR), Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Docket No. RM21-17-000. Core aspects of this FERC initiative and PJM's initial comments speak to the decarbonized future that is at the heart of the grid of the future.

Onshore wind continues to interconnect to the grid, but current trends show it to be more concentrated in western areas of the PJM footprint. Offshore wind is also emerging as a major source of power, seeking to interconnect to the grid along PJM coastal states. Although offshore wind is on a longer planning horizon, the potential for development is substantial. PJM must solve the challenges that these locationally constrained resources present and address the interregional implications associated with offshore wind lease areas that can also serve regions north and south of PJM RTO borders for states along the eastern seaboard.

**Offshore Wind Transmission Study**

An initial assessment of the transmission needed to interconnect the anticipated growth in renewable generation was completed as part of the Offshore Wind Transmission Scenario Study Phase 1. The study consisted of multiple scenarios that integrated between 30,000 MW and 80,000 MW of renewable generation and identified the need for as much as $3 billion in transmission upgrades to integrate PJM coastal states' offshore wind targets, as well as RPS goals across the entire RTO footprint, in the next 10–15 years. The analysis provides a view as to the magnitude of transmission expansion that will be needed to integrate the growing number of renewable resources.

With a generation fleet fuel mix shift from conventional generation resources to variable and/or duration-limited, inverter-based resources, a number of key reliability attributes have been identified that will need increased focus to ensure reliable operation throughout the transition to a decarbonized grid. These reliability attributes include inertia and frequency control, ramping capability, short circuit, and voltage control as discussed in the white paper, PJM's Evolving Resource Mix and System Reliability.[2]

## Future Impacts to Load Forecasts

**Distributed Energy Resources**

Currently, PJM Planning studies account for retail DER through the load forecast by netting load by the amount of forecast DER. This approach may be adequate at low levels of DER but is likely problematic with a substantial increase. With such an increase, PJM may not be accounting for the full load that must otherwise be served absent DER. Nonetheless, DER may provide benefits given their proximity to load and thereby reduce the burden on transmission if load were otherwise served by more distant sources.

Research shows an increasing trend toward customer installation of resources behind their electric meter. These resources can take the form of renewable resources stimulated by state programs, local generation installed for individual reliability needs, etc. Such resources clearly impact the operation of local distribution grids, but they can also impact bulk power system operations to the extent they impact net load to be served, transmission facility power flows, local voltage conditions, etc. The continued penetration of DER will require close and effective coordination between PJM and distribution operators in order to ensure reliability and efficient operations given the behavior of these resources.

The trend with DER interconnections – currently consisting primarily of rooftop solar, which has been steadily growing in recent years – may increase as a result of FERC Order 2222. The intent of the order is to reduce barriers to DER participation in wholesale markets by incorporating processes to permit the aggregation of smaller-sized resources.

[2] PJM's Evolving Resource Mix and System Reliability, March 30, 2017, Figure 6, page 16: https://www.pjm.com/-/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx

**Electrification**

More directly, the key elements driving future peak load levels and load shape are the electrification of transportation and building heating. A key finding of this report is that electrification of light-duty vehicles is likely to be the main trend for which PJM must prepare.

Although recent electric vehicle (EV) trends have been relatively modest, PJM's expectation is that policies at the federal and state level will incentivize a faster pace of EV adoption. Consumer EV charging behavior will impact the load demand curve shape. The impact is expected to be greater in the winter when the curve tends to be flatter, versus the summer when there is more opportunity to shift charging times. With appropriate policies to incentivize charging at off-peak hours, the bump in peak demand can be mitigated in part, even as overall energy consumption increases.

The impact of building heating electrification appears to be less certain given the economics of switching from oil or gas heating, especially in the colder geographic areas of the PJM footprint. Electrification of building heating appears to be on a much longer horizon with less certainty.

## The Role of Emerging Technologies

Studies are already identifying the need for additional transmission capability to make the transition to a more decarbonized grid. For example, as mentioned above, PJM recently completed scenario studies to accommodate offshore wind and other renewables that identified the need for significant transmission upgrades. Similarly, PJM studies examining energy transition and its impact from a markets perspective have also identified the need for grid expansion.

The needs of the future grid in the PJM region will likely require a range of solutions. While new transmission lines on new rights-of-way continue to be an option for developers, the attendant siting and permitting, time to construct, and cost to build can be formidable challenges. For these and other reasons, PJM anticipates that innovative solutions that maximize the use of existing facilities and existing transmission corridors will play a role in meeting the future grid's needs. Among the technologies discussed in this paper are dynamic line ratings (DLRs), specialized conductor designs, compact tower construction, power-flow control devices and grid-forming Flexible AC Transmission System (FACTS) devices.

## Resilience

A resilient grid must be able to withstand larger-scale system disturbances, to which it is difficult to attach probabilities and that can exceed conventional NERC planning N-1-1 and operations N-1 criteria. Generation and transmission low-probability, high-impact contingencies can significantly impact PJM's ability to serve load reliably. Heavy reliance on intermittent variable resource types raises resilience concerns, as the impact of the February 2021 arctic event impact on ERCOT, SPP and MISO demonstrated.

# 2. Generation Shift Drives Future Grid Expansion

Across the PJM service area, as in other areas of the country, the generation fleet fuel mix continues to shift. Driven by public policy (including RPS mandates and environmental regulations) and abundant shale natural gas in the PJM footprint, coal-fired generation is retiring and being replaced by renewable-powered and natural gas-fired generation. From 2012 through 2021, 41,211 MW of generation in the PJM footprint retired, including more than 31,833 MW from 154 coal-fired units, 135 of which were more than 40 years old. These deactivated units have been replaced by more than 43,000 MW of new resources, including over 3,000 MW of solar generation and 6,000 MW of wind generation. As this section discusses, another estimated 105,000 MW of renewables, coupled with age and public-policy-driven deactivations, will drive grid expansion.

## *2.1 Trends in Renewable Power*

PJM's diverse installed capacity resource profile today includes generation powered by natural gas, coal, nuclear, wind and solar, coupled with demand response and storage. However, increasing public demand for cleaner sources of electricity, combined with public policy standards and goals, is driving unprecedented growth in renewable resources. As discussed below, PJM generation interconnection queue activity reflects a shift from interconnection requests by natural gas generation to solar, wind and storage.

### 2.1.1 Geography

PJM's footprint draws attention to the two locational dimensions of wind-powered generation:

**1 |** Onshore, mainly along the Appalachian Mountains' ridge and PJM's western subregion

**2 |** Offshore, along the coasts of New Jersey, Maryland, Delaware, Virginia and North Carolina

Only through careful scenario analyses will PJM be able to evaluate the holistic impact on the need for grid expansion. Notably, unlike other areas of the country, renewable-powered generation developers in the PJM footprint are not seeking interconnection far from load centers. This trend has significant implications for future grid planning, insofar as the need for major long-distance, possible multi-state, backbone transmission lines to deliver RPS-mandated power may not necessarily be the most efficient first-choice grid solution.

**Table 1** and accompanying **0** show that of the 691 renewable generation projects currently in-service, 613 generation projects (88.7%) are geographically located 100 miles or less from load centers, 74 generation projects (10.7%) are geographically located between 101 miles to 200 miles from load centers, and only four generation projects (0.6%) are geographically located more than 200 miles from a load center.

**Table 1.** PJM Current In-Service Generation – Geographical Distance From Load Center

| Distance From Load Center | In-Service Generating Facilities: Count | | | | | MW | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Renewable | Fossil | Nuclear | Other | **Total** | Renewable | Fossil | Nuclear | Other | **Total** |
| 0–100 miles | 236 | 270 | 17 | 90 | **613** | 20,242 | 124,617 | 30,838 | 1,007 | **176,704** |
| 101–200 miles | 47 | 20 | 1 | 6 | **74** | 7,014 | 11,778 | 1,819 | 59 | **20,670** |
| 201–300 miles | 1 | 3 | 0 | 0 | **4** | 250 | 1,846 | 0 | 0 | **2,096** |

**Renewable**: Solar, Wind, Hydro | **Fossil:** Natural Gas, Coal, Oil | **Other:** Biomass, Landfill, Battery, Flywheel

**Map 1.** PJM Current In-Service Generation – Geographical Distance to Load Center

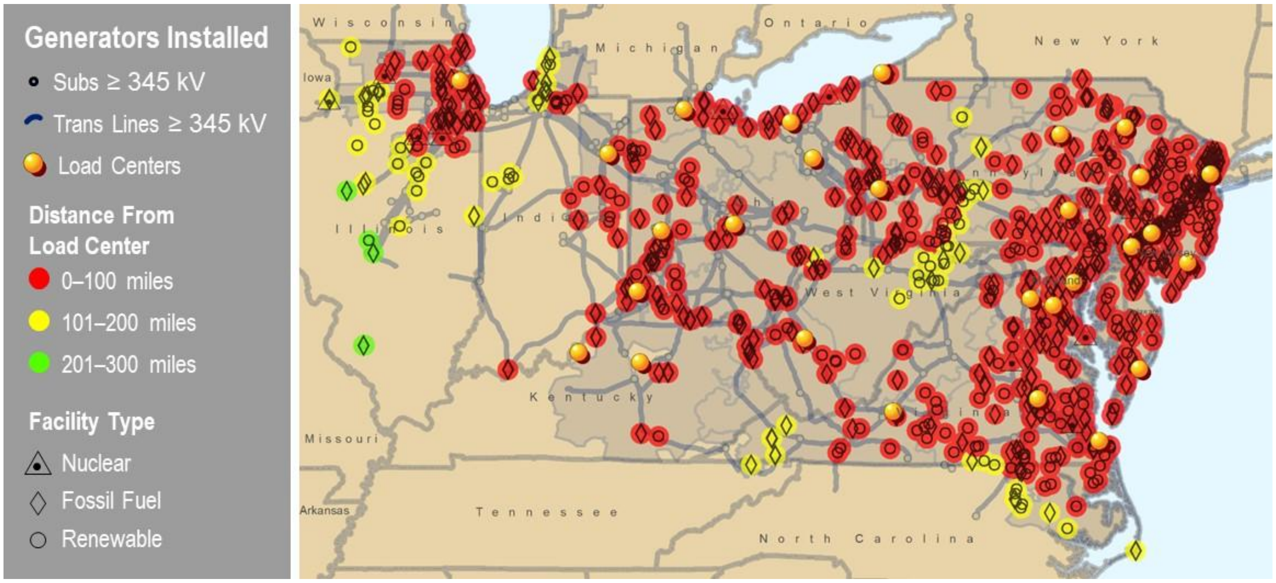


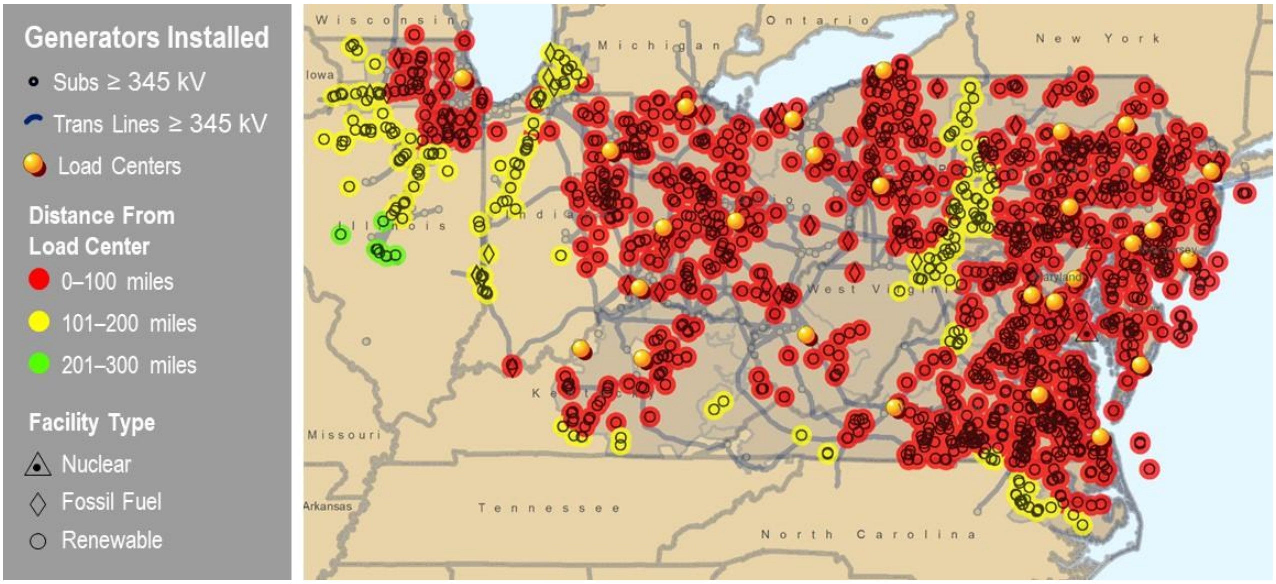

**Table 2** and **Map 2** show that of the 1,826 planned generation projects currently in PJM’s interconnection queue, 1,560 planned generation (85.4%) projects are geographically located 100 miles or less from load centers, 254 planned generation projects (13.9%) are geographically located between 101 miles to 200 miles from load centers, and only 12 planned generation projects (0.7%) are geographically located more than 200 miles from a load center. Thus, future interconnection queue generation will remain close to load centers within the PJM service area, with only a marginal reduction in relative proximity.

**Table 2.** PJM Interconnection Queue Projects – Geographical Distance From Load Center

| Future Projects | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Distance From Load Center | Count | | | | | MW | | | | |
| | Renewable | Fossil | Nuclear | Other | **Total** | Renewable | Fossil | Nuclear | Other | **Total** |
| 0–100 miles | 1,212 | 98 | 6 | 244 | **1,560** | 108,435 | 17,552 | 190 | 19,055 | **145,232** |
| 101–200 miles | 200 | 13 | 0 | 41 | **254** | 27,784 | 4,588 | 0 | 3,365 | **35,737** |
| 201–300 miles | 8 | 0 | 0 | 4 | **12** | 1,008 | 0 | 0 | 186 | **1,194** |

**Renewable**: Solar, Wind, Hydro | **Fossil:** Natural Gas, Coal, Oil | **Other:** Biomass, Landfill, Battery, Flywheel

**Map 2.** PJM Interconnection Queue Projects – Geographical Distance From Load Center




### 2.1.2 State Renewable Portfolio Standards

PJM's grid of the future will enable customer access to renewable power at much greater levels than today, driven by states' RPS mandates. Ten states in the PJM footprint, plus the District of Columbia, have enacted them as shown in **Table 3** and **Map 3**, below.

These mandated state RPS targets require that a certain percentage of a state's load are served by qualified renewable energy resources. RPS policies have functioned as a significant driver of renewable resource development. Across the nation, and in PJM, many states have increased their RPS targets in recent years in pursuit of accelerated decarbonization objectives. Since 2018, Delaware, the District of Columbia, Illinois, Maryland, New Jersey and Virginia have all established new RPS targets.

State RPS policies also vary by eligible resource technology, in-state resource carve-out requirement, and required qualified resource location. Whether characterized as a goal or target, the majority of PJM states are moving toward a decarbonized grid over the course of the next 20–30 years. In addition, some in-state resource carve-outs are crafted as a percentage of energy, while others specify the minimum renewable capacity to be developed in-state. The variability in policies has not been a hindrance to building new renewable generation and, in fact, has provided developers both direction and flexibility in siting planned renewable generators. As a result, renewable generation is now the most prominent resource type in PJM's interconnection queue in each state, including those that have historically been more fossil fuel intensive.

**Table 3.** PJM State RPS Targets

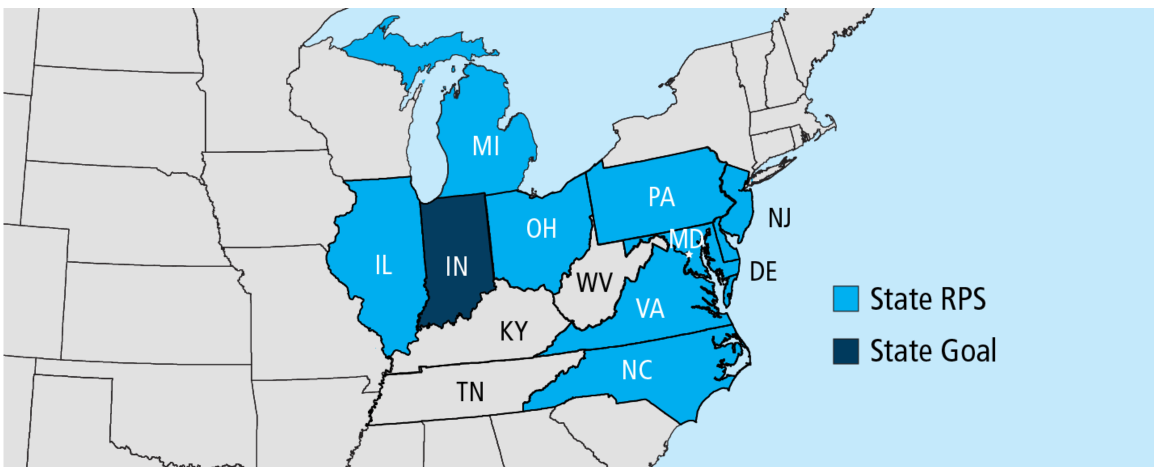
**State RPS Targets***

| | | | | | |
|---|---|---|---|---|---|
| ☼ | **NJ:** 50% by 2030** | ☼ | **PA:** 18% by 2021*** | | **OH:** 8.5% by 2026 |
| ☼ | **MD:** 50% by 2030** | ☼ | **IL:** 50% by 2040 | | **MI:** 15% by 2021 |
| ☼ | **DE:** 40% by 2035 | ☼ | **VA:** 100% by 2045/2050 (IOUs) | | **IN:** 10% by 2025*** |
| ☼ | **DC:** 100% by 2032 | ☼ | **NC:** 12.5% by 2021 (IOUs) | | |

☼ Minimum solar requirement

* Targets may change over time; these are recent representative snapshot values.
** Includes an additional 2.5% of Class II resources each year
*** Includes non-renewable "alternative" energy resources

**Map 3.** PJM State RPS Targets and Goals




## 2.1.3 120,000 MW by 2050 – Energy Transition Analysis Insights

As noted above, the public policies vary widely among the PJM states in terms of the types of resources targeted, how achievement is measured, and the time frame to achieve desired goals. Nonetheless, the estimated impact, based on PJM's energy transition analysis, is that wind and solar resources will grow between three and eight times (in installed capacity terms) over the course of the next 15 years, potentially adding another 105,000 MW to the existing level of roughly 15,000 MW of renewable wind, solar and storage resources.

The energy transition analysis culminated in a report, Energy Transition in PJM: Frameworks for Analysis[3] published on Dec. 15, 2021, and has informed the grid of the future road map discussed in this paper. The analysis studied three scenarios of varying levels of renewable penetration comprising offshore wind, onshore wind and solar power as shown in **Figure 1**:[4]

**1 |** Business-as-Usual Reference Case – The amount of renewable energy penetration levels is modeled after RTEP 2023 power-flow cases.

[3] Energy Transition in PJM: Frameworks for Analysis, Dec. 15, 2021.

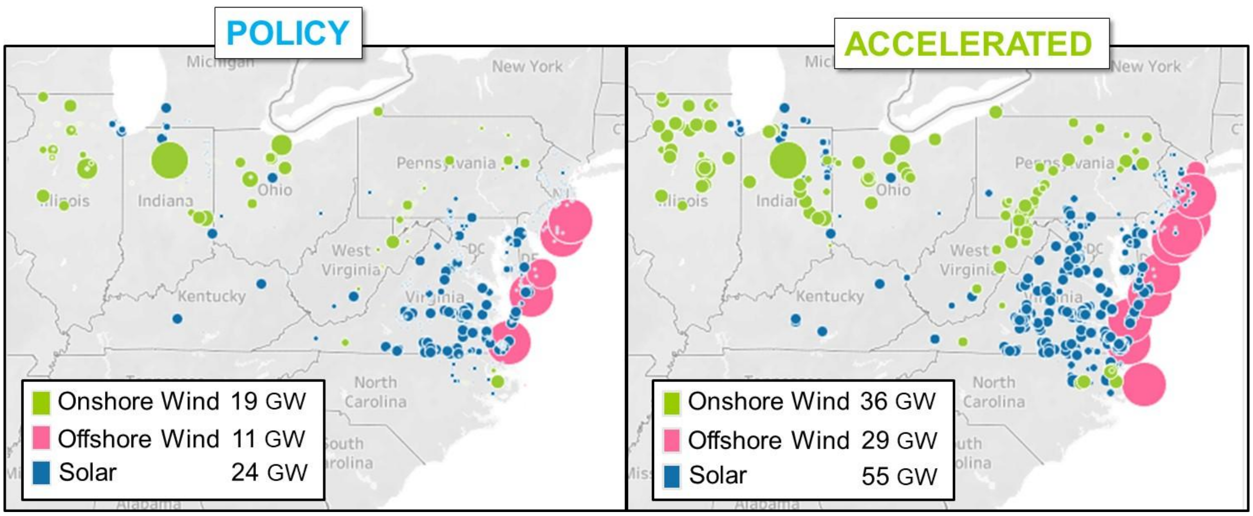
[4] Ibid. page 6.

**2 |** Policy Scenario Case – 22% of the RTO's energy comes from renewable generation based on analysis of state and utility corporate clean energy targets through 2035.

**3 |** Accelerated Scenario Case – 50% of the RTO's energy comes from renewable generation. This scenario referenced additional state and corporate clean energy targets extending to 2050.

PJM's fuel mix will drastically change due to the state and corporate clean energy policy targets, with solar and wind generation increasing and replacing coal and natural gas generation. With that in mind, the energy transition in PJM analysis evaluated hourly market PLEXOS simulations, with nodal model monitoring at 230 kV and higher, for each of the three renewable penetration scenarios above.

**Figure 1.** Renewable Generation Expansion in Policy and Accelerated Scenarios – PJM Energy Transition Analysis




The energy transition analysis results yielded a number of significant conclusions, including the following, with a more direct impact on PJM's future grid road map:

- As the penetration of renewable resources increases, the risk profile shifts toward later hours in the evening, as peak net demand (load minus renewable generation) shifts toward sunset.[5]
- No load-shedding events were observed in the energy market simulation.[6]
- Adding zero-marginal-cost renewable resources decreased the average locational marginal price (LMP) in all scenarios (by as much as 26%). Consequently, the overall size of the energy market in terms of revenues to resources and charges to load shrunk by a maximum of 40%.[7]

[5] Ibid. page 1.
[6] Ibid. page 1.
[7] Ibid. page 2.

- The analysis showed the advantages of a robust interconnection between systems. PJM's exports increased by 140%, and its interchange with the Midcontinent Independent System Operator (MISO) peaked at more than 20 GW of power flow. At the time when the simulation results for this study were completed (2020), 20 GW of power flow from PJM to MISO represented more than double the maximum historical level. Interestingly, during the Texas winter event of 2021, PJM exported more than 14 GW to MISO, emphasizing once again the importance of the interconnection and overall generation portfolio diversity.[8] As the power flow in the network changed, so did congestion patterns. Simulations showed an overall increase in congestion hours.[9]

- A significant amount of renewable curtailment was needed to manage transmission limitations and minimum generation events.[10]

### 2.1.4 RPS Impacts on Queue Activity

The impact of states' RPS policies can be seen in **Figure 2,** which shows interconnection request trends by queue – AB2 through AH1 – and fuel type over the past six years in terms of unit Maximum Facility Output (MFO). Trends show that requests for solar- and wind-powered interconnection, together with storage, continue to grow steadily, queue-over-queue, while requests for new natural gas plants have ebbed.

**Figure 3** provides another perspective by showing the queue status as of Dec. 31, 2021, in terms of requested Capacity Interconnection Rights (CIRs). This look at PJM's queue activity demonstrates that renewable developers see the market opportunities enabled by RPS policies, given that generators must have CIRs to participate in PJM's capacity market.

**Figure 4** shows a time-based view of forecast growth of onshore and offshore wind generation alone, indicating that future grid expansion planning must ensure that over 46,000 MW of wind power can interconnect reliably.

As PJM's generation mix shifts more toward renewables, PJM must evaluate how to maintain or even increase the level of NERC-defined essential reliability services to ensure system reliability. This is particularly critical in the face of the extreme weather events recently experienced across the United States against the backdrop of increasing renewables penetration, retirements of dispatchable generation, and growing reliance on interregional transfer capability.

[8] Ibid. page 3.

[9] Ibid. page 3.

[10] Ibid. page 12.

**Figure 2.** PJM Queued Generator Interconnection Requests[11] (Megawatts, MFO[12])

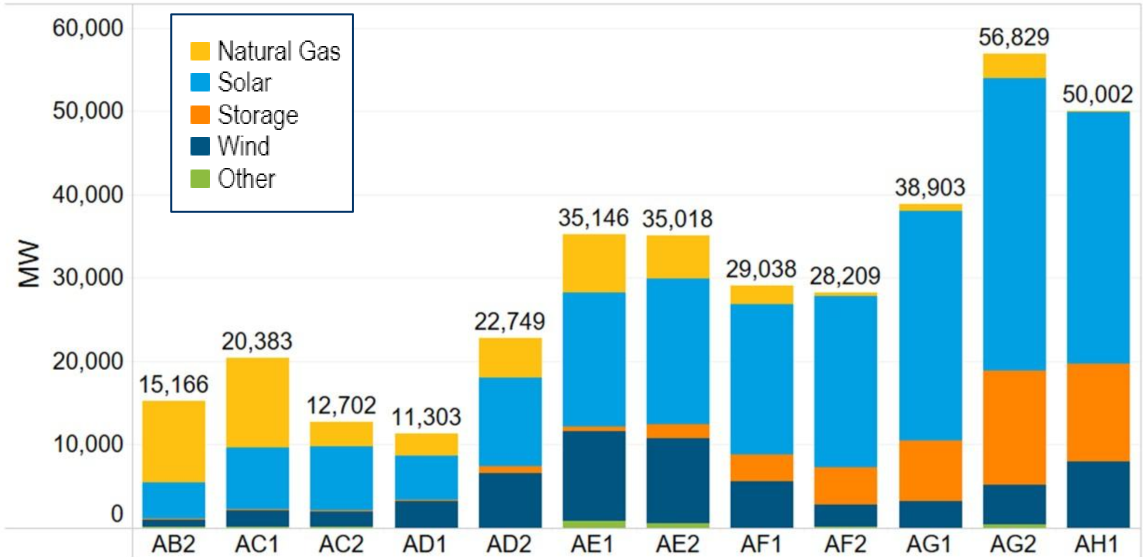
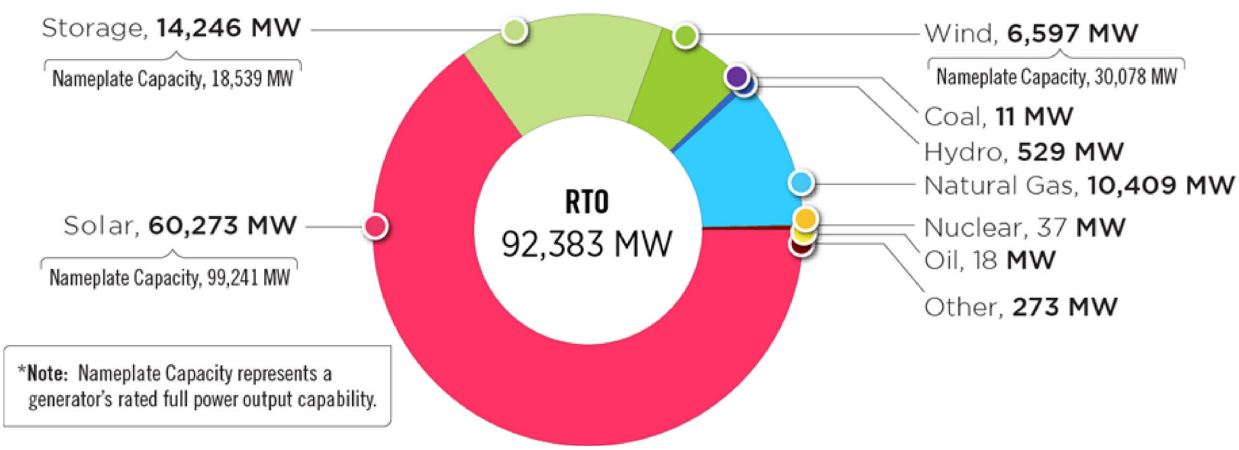



**Figure 3.** PJM Generator Interconnection Request Queue by Fuel Type (Requested Capacity Interconnection Rights, Close of Queue AH1, Sept. 30. 2021)

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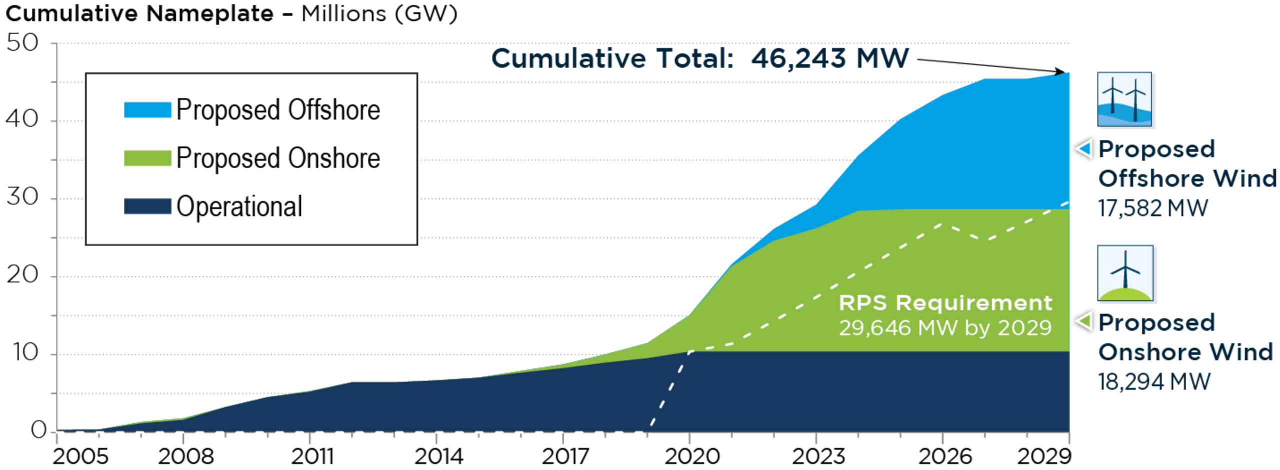
[11] Data for Queue AH1 is preliminary.

[12] MFO stands for Maximum Facility Output, which can also be called nameplate capacity, and is defined in PJM's Open Access Transmission Tariff: "…the maximum (not nominal) net electrical power output in megawatts, specified in the Interconnection Service Agreement, after supply of any parasitic or host facility loads, that a Generation Interconnection Customer's Customer Facility is expected to produce, provided that the specified Maximum Facility Output shall not exceed the output of the proposed Customer Facility that Transmission Provider utilized in the System Impact Study."

**Figure 4.** Wind Installed Capacity in PJM – Operational and Proposed




### 2.1.5 Onshore Wind Trends

Federal and state legislative and regulatory RPS and public policy initiatives continue to drive the development of onshore wind-powered generators across the RTO, bringing into clear focus the critical role of transmission in delivering power reliably. Wind-powered generating resources have played a growing role in meeting PJM customer load requirements since April 2002 when the first wind generator, located in Fayette County, Pennsylvania, was interconnected to the PJM transmission grid with total nameplate capacity of 15 MW. Since then, total wind nameplate[13] capacity has grown to 11,000 MW within PJM.

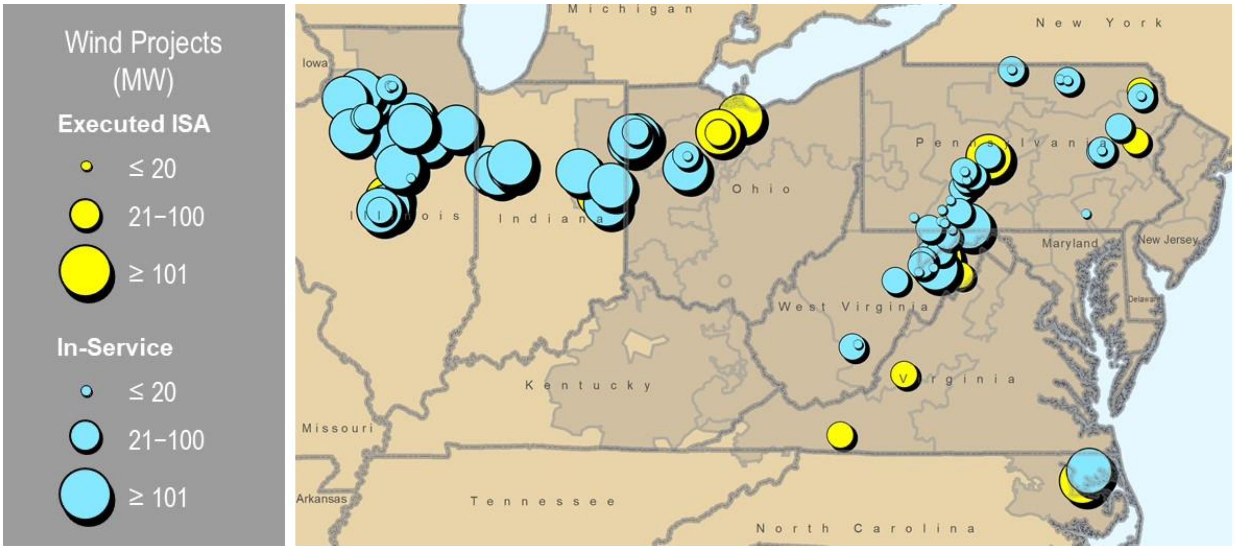
#### 2.1.5.1 Queue Activity

Renewables growth is not emerging uniformly across PJM's footprint. Growth is occurring fastest in areas with favorable wind speed and sustained duration in order to achieve energy production levels that generate profit-making revenue streams. PJM continues to see developer interest in constructing wind-powered generating facilities throughout its footprint with clusters emerging in PJM's western subregion (including Illinois, Indiana and Ohio) and along the Allegheny Mountains in Pennsylvania and West Virginia. **Map 4** shows generator interconnection requests received by PJM through the close of Queue AG2 that are currently at the Interconnection Service Agreement execution phase or later.[14] These requests total 14,976 MW. **Map 4** shows interconnection requests for 15,338 MW of wind-powered generation (also through the close of Queue AG2) that are currently under active study (i.e., they have reached the feasibility, impact or facility study stage). The trend that **Map 4** shows earlier in the interconnection process demonstrates ongoing developer interest in PJM's western subregion.

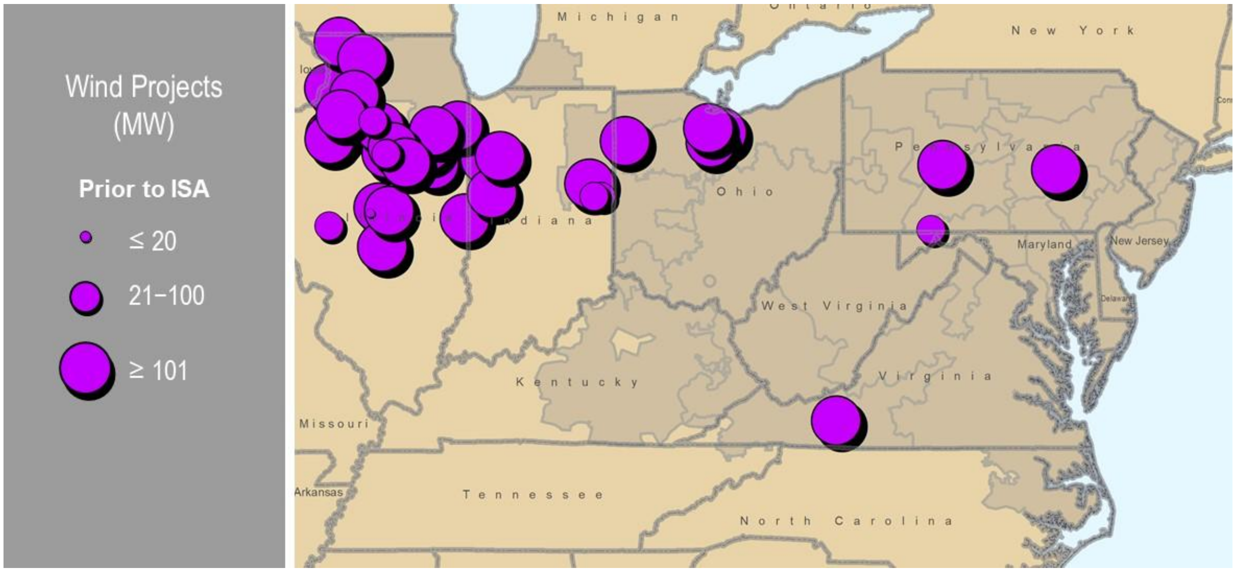
[13] Nameplate capacity represents a generator's rated full power output capability and is typically much greater than CIRs for wind- and solar-powered generators. This is because, while some resources can operate continuously like conventional fossil-fueled power plants, power output from renewable resources like wind and solar can be variable.

[14] PJM's generation interconnection process has three study phases: feasibility, system impact and facilities studies, to ensure that new resources interconnect without violating established NERC, PJM, transmission owner and regional reliability criteria. This culminates in the execution of an Interconnection Service Agreement. Each generator that completes the necessary transmission system enhancements becomes eligible to interconnect to the grid and to participate in PJM capacity and energy markets.

**Map 4.** Onshore Wind Generation Project Locations Through Queue AG2 Currently at ISA Phase or Later




**Map 5.** Onshore Wind Generation Project Locations, Through Queue AG2, Prior to ISA




### 2.1.6 Offshore Wind Trends

The area off the U.S. Atlantic coast encompasses a major wind-energy resource that could potentially yield thousands of megawatts of power. Efficiently harnessing that energy through the construction of offshore wind farms will require extending the existing transmission grid to deliver power ashore to users, particularly to load centers along the East Coast.

Offshore wind has been a source of power for decades in Europe and other parts of the world. In the United States, and in PJM more specifically, it remains a nascent technology. Through September 2021, only two operational offshore wind farms in the United States have reached commercial operation: the 30 MW Block Island Wind Farm off the coast of Rhode Island and the 12 MW Coastal Virginia Offshore Wind Pilot Project near Virginia Beach. Although current operational capacity totals are low, offshore wind is expected to be a major contributor to U.S. clean energy and decarbonization initiatives over the coming decades.

To date, the primary location for offshore wind development in the United States has been the Atlantic coast, primarily in New England and the mid-Atlantic states. However, the Pacific coast, Hawaii, the Gulf of Mexico and the Great Lakes are also being considered for offshore wind potential. **Table 4** provides an overview of every state's current offshore wind procurement targets.

**Table 4.** Current Offshore Wind Policy Targets

| State | Offshore Wind Target (MW) | Target Date |
|---|---|---|
| Connecticut | 2,300 | 2030 |
| Maryland | 2,022.5 | 2030 |
| Massachusetts | 5,600 | 2035 |
| New Jersey | 7,500 | 2035 |
| New York | 9,000 | 2035 |
| North Carolina[15] | 8,000 | 2040 |
| Rhode Island | 430 | - |
| Virginia | 5,200 | 2035 |
| **Total** | **40,053** | |

Within the PJM service area, Maryland, New Jersey and Virginia have all established offshore wind targets totaling 14,722.5 MW (36% of the Atlantic coast targets noted in **Table 4** with planned in-service dates by 2035). Also, North Carolina recently announced an 8,000 MW target by 2040 via a June 2021 executive order. Legislation is driving offshore wind objectives in Maryland and Virginia. New Jersey's goal is supported by a combination of legislation and an executive order.

Several projects that will be used to achieve the PJM states' offshore wind targets have already been selected. New Jersey has conducted two solicitations to date to award Offshore Wind Renewable Energy Certificates (ORECs) to three projects totaling 3,758 MW.[16] Maryland has awarded ORECs to four projects totaling 2,022.5 MW, with their most recent award coming in 2021.[17] Within Virginia, Dominion Energy has already proposed 2,640 MW of offshore wind capacity to be constructed by 2026 via three phases of 880 MW each. In addition to these announced projects, Avangrid Renewables is advancing a 2,500 MW merchant offshore wind project off the coast of North Carolina.

While offshore wind development in the United States has largely been led by individual state initiatives, the Biden administration introduced a federal offshore wind policy target in March 2021. Through a shared goal between the Department of the Interior, Department of Energy and Department of Commerce, the United States is now pursuing 30 GW of operational offshore wind by 2030. As part of its plan to reach this milestone, the Biden administration

[15] Target in North Carolina, per executive order

[16] New Jersey's first solicitation was awarded to Ørsted's 1,100 MW Ocean Wind I project. The second solicitation was awarded to Ørsted's 1,148 MW Ocean Wind II project and 1,509.6 MW Atlantic Shores project, which is a joint venture between EDF Renewables North America and Shell New Energies.

[17] Maryland's first two offshore wind solicitations were awarded to Ørsted's 120 MW Skipjack project and US Wind's 248 MW MarWin project. Maryland's third offshore wind solicitation awarded ORECs to Ørsted's 846 MW Skipjack 2.1 project and US Wind's 808.5 MW MarWin II project.

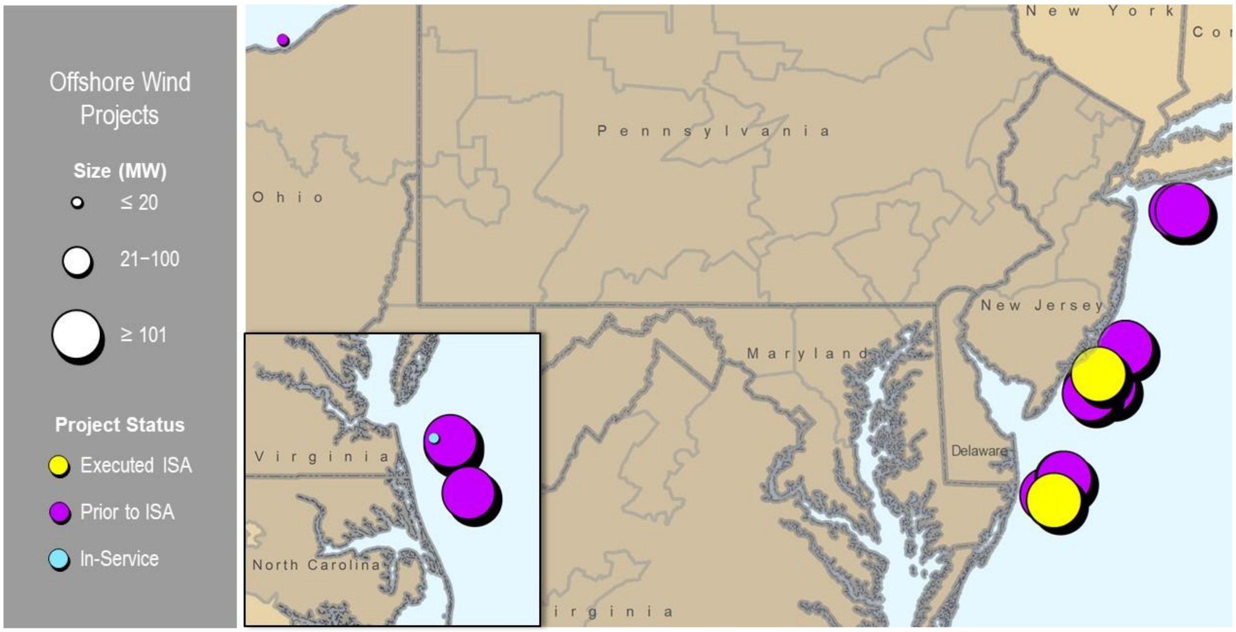
plans to support the Bureau of Ocean Energy Management (BOEM) in issuing new lease sales[18,19] and reviewing at least 16 construction and operations plans by 2025.[20] The national 30 GW target is also believed to be a starting point for an eventual offshore wind goal of 110 GW by 2050.[21]

The injection of thousands of megawatts from offshore wind will fundamentally change how power flows over the transmission grid in the Northeast and mid-Atlantic. Generation will now be located closer to load centers along the I-95 corridor; this area of the grid was originally served mainly by west-to-east power flow from large mine-mouth coal generating stations in western Pennsylvania and beyond and, later, shale natural gas-fired plants in central Pennsylvania. This unfolding scenario will drive the need for new transmission assets and system configurations to maximize power delivery to onshore load.

#### 2.1.6.1 Queue Activity

The capital costs involved with building offshore wind facilities and the supporting transmission upgrades present a major barrier to offshore wind entering a competitive market without financial support at the state or federal levels. Given the costs of developing offshore wind resources, these facilities will not likely enter the PJM queue absent: (1) the expectation of contributing to a state's offshore wind target; and (2) receiving public funding. As a result, the queued offshore wind resource activity illustrated in **Map 6** is likely to continue to follow existing and anticipated offshore wind policies to the extent that financial support is available.

**Map 6.** PJM Offshore Wind Generation Locations (Through Queue AG2)




[18] On Feb. 25, 2022, the Department of the Interior announced results of its competitive offshore energy lease sale for the New York Bight: https://www.doi.gov/pressreleases/biden-harris-administration-sets-offshore-energy-records-437-billion-winning-bids-wind

[19] Additional information about the New York Bight can be found online: https://www.boem.gov/renewable-energy/state-activities/new-york-bight

[20] Fact Sheet: Biden Administration Jumpstarts Offshore Wind Energy Projects to Create Jobs (March 29, 2021) – https://www.whitehouse.gov/briefing-room/statements-releases/2021/03/29/fact-sheet-biden-administration-jumpstarts-offshore-wind-energy-projects-to-create-jobs/

[21] *Id.*

#### 2.1.6.2 State Agreement Approach

The State Agreement Approach (SAA) is a PJM Operating Agreement provision that allows one or more states to pursue public policy requirements as part of PJM RTEP process study planning parameters. States, in collaboration with PJM, voluntarily agree to develop identified transmission solutions identified in RTEP process studies. States are subsequently responsible for 100% of the cost allocation of each such SAA-derived RTEP projects for which they elect to move forward.

The New Jersey Board of Public Utilities (NJBPU) initiated PJM's SAA in November 2020 by soliciting transmission proposals to accommodate full integration of 7,500 MW of planned offshore wind-powered generation by 2035. The parties filed an SAA agreement[22] with FERC on Jan. 27, 2022, outlining how New Jersey will put PJM's competitive planning process to work in pursuit of its offshore wind goals. The agreement details the contractual commitments and responsibilities of the NJBPU and PJM regarding the competitive selection of transmission solutions.

New Jersey's initiation of the SAA is the first time a state in the PJM region has elected to pursue achieving public policy requirements through PJM's competitive RTEP process. In this instance, doing so will enable the construction of large-scale, offshore wind-powered generation. This joint New Jersey-PJM SAA experience provides an effective planning blueprint going forward for states to pursue their own respective RPS and other public policy goals as part of effective, coordinated planning within PJM for the grid of the future.

#### 2.1.6.3 PJM's Offshore Wind Transmission Study

Planning grid of the future road map efforts are already underway as part of PJM's Offshore Wind (OSW) Transmission Study,[23] mentioned earlier, and initiated in response to a request from the Organization of PJM States (OPSI)[24] to look at various future OSW scenarios. The study's first phase, completed in October 2021, examined onshore grid reinforcements needed by 2035 to deliver wind-powered generation located off the coasts of Maryland, New Jersey and Virginia, as part of achieving all RPS targets across all PJM states.

Multiple scenarios examined the integration of renewables at levels between 30,000 MW and 80,000 MW. The study identified the need for an estimated $3 billion of bulk electric system[25] transmission enhancements over the next 10 to 15 years to integrate PJM's coastal states' OSW targets and to meet RPS goals across the entire RTO footprint. The analysis provides a sense of the magnitude of grid expansion needed to integrate growing renewable resource penetration. As PJM continues to implement its road map to enable a decarbonized grid, additional OSW scenario study analysis will examine accelerated renewable penetration levels and will incorporate a more in-depth assessment of the impacts from higher levels of building heating and transportation electrification.

By synchronizing transmission planning across all its coastal states' offshore wind deployment, PJM is able to identify transmission solutions that offer a more efficient and economic means for states collectively to achieve their offshore wind policy objectives than if each pursued respective objectives independently. The OSW study does not commit any PJM state to any transmission grid enhancement. Rather, it serves as an opportunity to identify the potential scope of coordinated transmission solutions to help inform state policymakers as they advance their offshore wind policy objectives. States can incorporate study findings into future offshore wind solicitations and related SAA-derived

[22] FERC Docket No. ER22-902

[23] https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx

[24] https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20191217-opsi-letter-re-october-board-to-board-discussion-follow-up.ashx

[25] Essentially, the bulk electric system comprises transmission facilities at 100 KV and higher.

transmission solutions. States ultimately reserve the right and ability to work together on transmission solutions for offshore wind and other clean energy objectives, or can defer to the existing PJM generation interconnection queue process in which generators are assigned cost responsibility for associated network transmission upgrades.

### 2.1.7 Solar Power Trends

Solar-powered generation is typically considered on the same terms as wind-powered generation as a key dimension in achieving RPS standards, as discussed earlier in **Section 2.1.2**. A key dimension of achieving those goals must necessarily account for industry experience, which has shown that as solar resources meet a larger share of the mid-day generation needs, non-solar resources are needed to ramp down in the morning and ramp up again in the evening to balance daily and seasonal solar unit output patterns. This system behavior will drive studies to examine the impact on power-flow patterns and potential for reliability criteria violations.

#### 2.1.7.1 Queue Activity

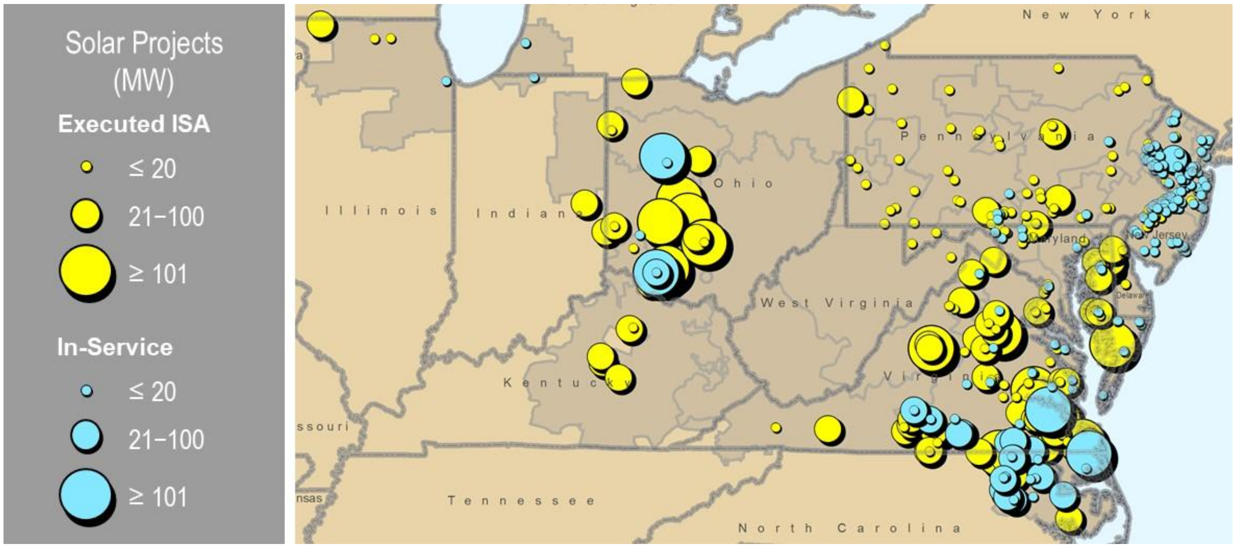
With approximately 175,000 MW of interconnection requests[26] in PJM's queue, nearly 100,000 MW, or 57%, of all submitted queue requests for CIRs have been for solar generation. In 2020, solar generation exceeded natural gas as the largest percentage of units, by fuel type, seeking CIRs. Solar interconnection requests more than doubled in 2020 over 2019, driven by federal and state public policy and broader fuel economics of other types of units.

The location of early utility-scale solar installations within PJM was driven by the financial incentives offered by specific states. To date, existing and planned solar generation with executed Impact Study Agreements (ISAs), totaling 13,453 MW, have been concentrated in these states, as shown on **Map 7**. However, queued solar projects seeking interconnection that have not yet reached ISA status – currently totaling approximately 140,000 MW – are shown on **Map 8** and indicate that the trend has shifted. These more recent additions to the interconnection queue demonstrate increasing geographic diversity across the PJM footprint, with growing numbers of new solar projects now in every state and transmission owner zone.

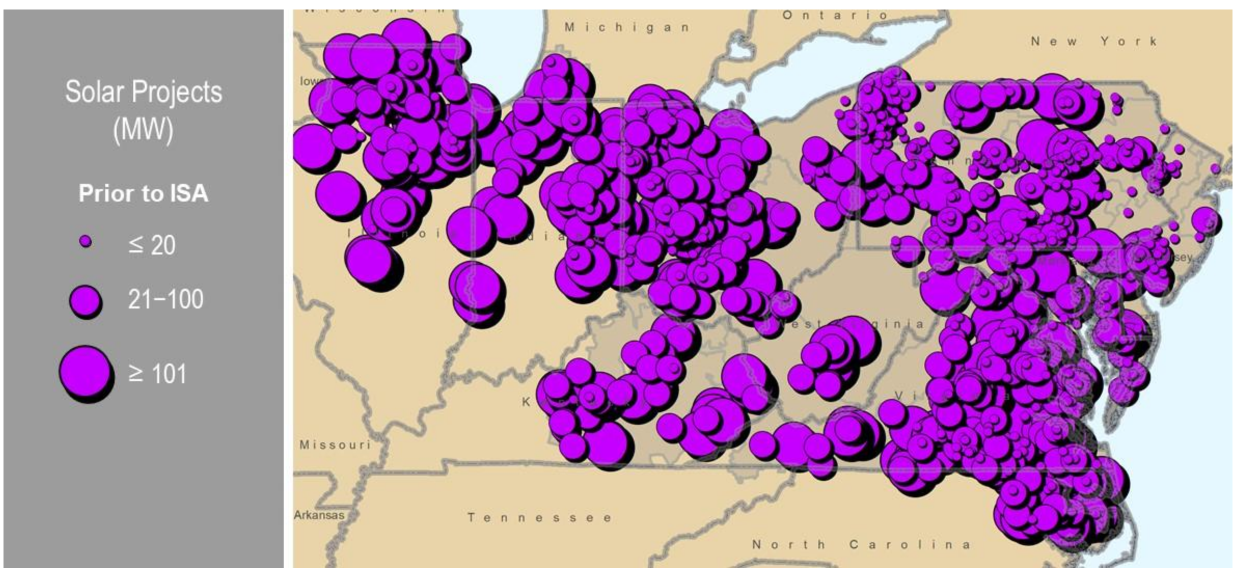
PJM recognizes that solar presents its own challenges, such as when low availability of solar power coincides with high power demand. To address this future grid risk, PJM studies must examine time-of-day and seasonal impact of solar on grid power-flow patterns. And, as with wind-powered generation, the inverter-based resource (IBR) power electronics associated with solar-powered generation also introduces concern with maintaining – or even increasing – the availability of sufficient levels of NERC-defined reliability attributes, an issue that PJM continues to examine.

[26] Through the close of Queue AG2 on March 31, 2021

**Map 7.** Utility-Scale Solar Installations in PJM: Currently In-Service Projects and Queued Projects Through Queue AG2, at Executed ISA Phase or Later




**Map 8.** Utility-Scale Solar Installation Interconnection Requests in PJM Through Queue AG2, Prior to ISA




### 2.1.7.2 State Solar Public Policy Drivers

States rely on solar power as one of the main resources to meet their RPS requirements. Eight of the 10 PJM states with mandatory RPS targets include solar-specific requirements, the details of which vary by state. Some include in-state solar carve-outs as a percentage of total state energy demand. Others permit their solar carve-outs to be met by solar resources located anywhere within the PJM footprint. Still others, particularly those located along PJM's seams, allow solar commitments from resources located outside the PJM footprint to meet RPS targets and goals.

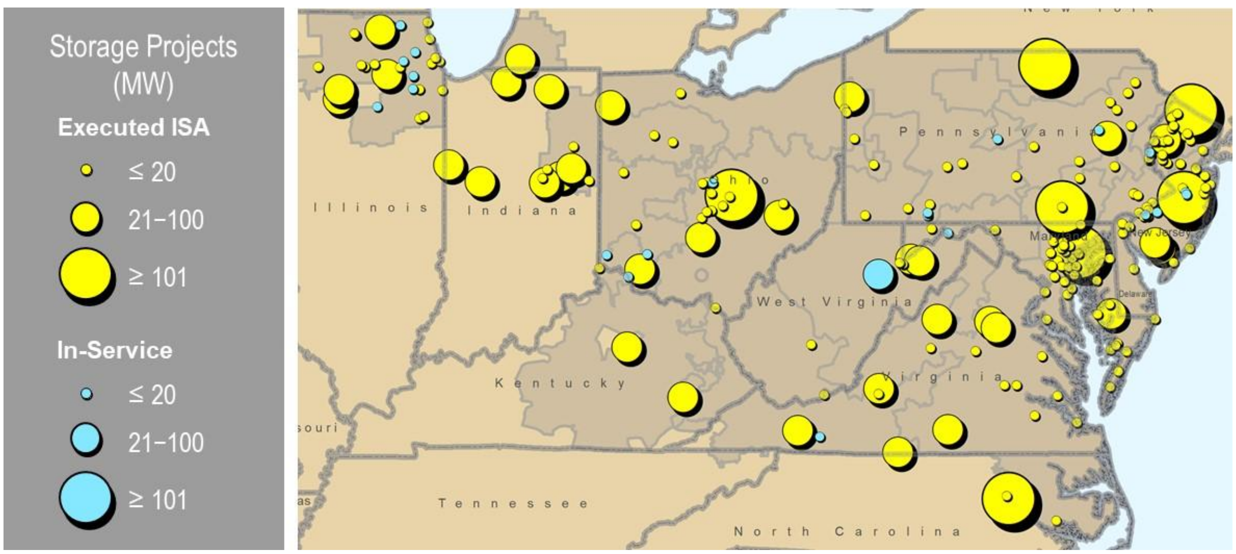
### 2.1.8 Storage and Renewable Plant Hybrids

Energy storage development continues to grow in PJM as in other RTOs. As solar generation increases across the PJM footprint, storage growth is expected to follow, particularly as part of co-located projects. Efficient grid operations in an era of rapid renewable energy resource growth will require increased electric system flexibility. Energy storage can help grid operators maintain stable power supply under varying wind and solar power output, driven by weather conditions and unit outages, and improve utilization levels of existing transmission facilities. PJM has worked with various companies and national laboratories to study storage use and to ensure that the PJM wholesale market can permit all forms of energy storage to participate. Storage as a transmission asset is discussed further in **Section 5.4.**

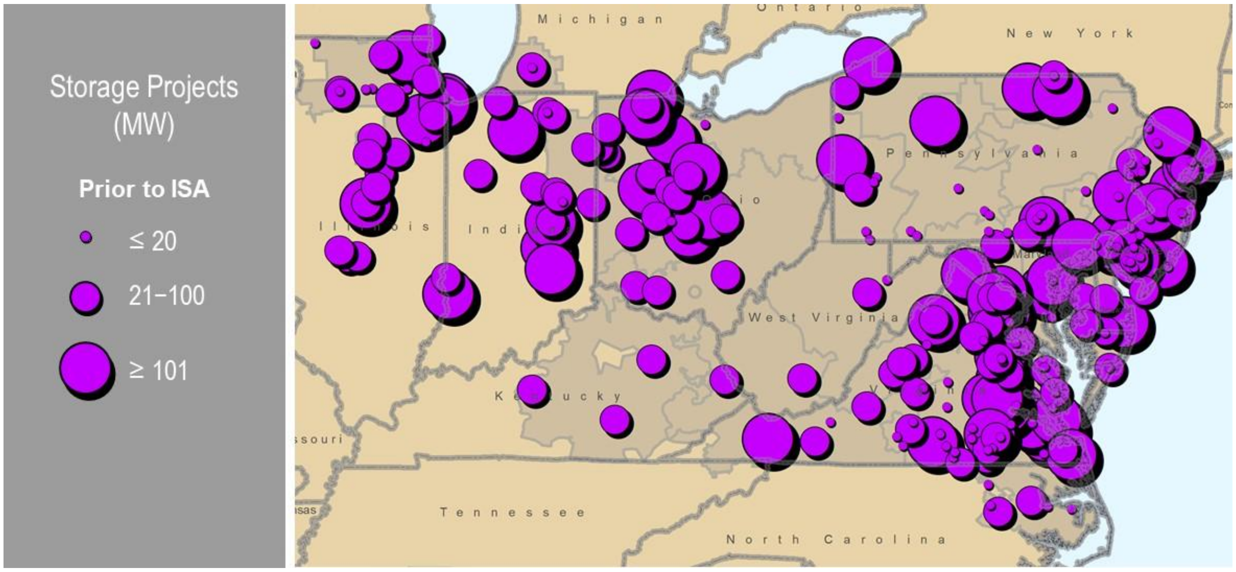
#### 2.1.8.1 Queue Activity

Queued storage resources total over 11,800 MW of interconnection requests for CIRs (over 15,800 MW on a nameplate capacity basis), as shown in **Figure 3** in **Section 2.1.4** and on **Map 9** and **Map 10.** This is in addition to the storage resources today comprising pumped-storage hydro totaling 5,000 MW and battery and flywheel energy storage totaling 300 MW. Pumped storage can participate in the PJM capacity, Energy, Regulation and Reserve markets.

**Map 9.** Storage Installations in PJM: Currently In-Service Projects and Queued Projects, Through Queue AG2, at Executed ISA Phase or Later



**Map 10.** Storage Installation Interconnection Requests in PJM through Queue AG2, Prior to ISA




### 2.1.8.2 State Public Policy Drivers

Storage development is also being driven by both explicit and implicit state policy objectives. Explicit state targets include Virginia's 3,100 MW of storage by 2035 and New Jersey's 2,000 MW target by 2030, as outlined in its 2019 Energy Master Plan.[27] Maryland also has an energy storage pilot program that was implemented in 2019 to develop storage capacity within the state.[28] Implicitly, storage is being developed to complement the influx of renewable resources driven by state RPS targets.

### 2.1.8.3 Impacts of Storage on Future Grid

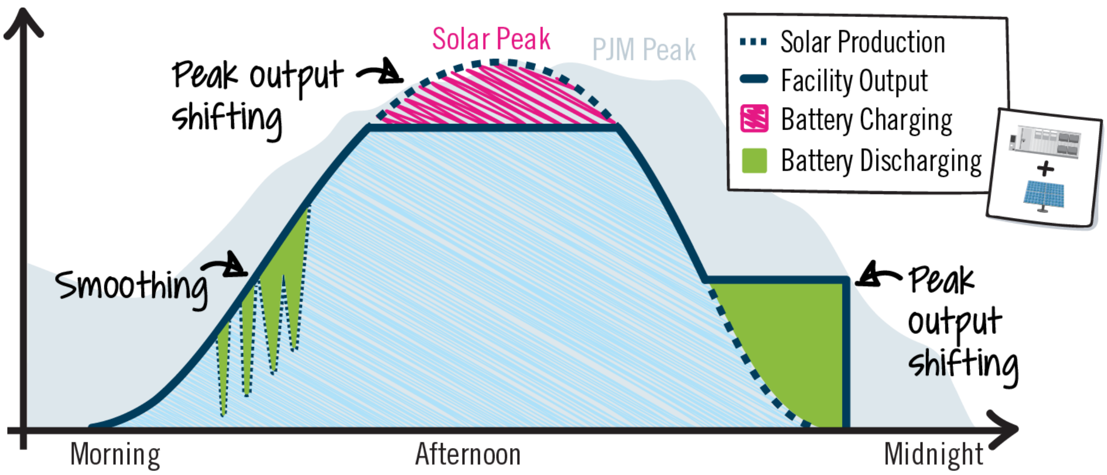
PJM recognizes that storage paired with renewables and transmission can optimize the delivery of power. To address the limited-duration issue, some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land, but each has its own connection to the grid) or is hybrid (in which the storage facility and generator share a common connection to the grid).

Whether co-located or hybrid, the net result with respect to solar power, for example, smooths minute-by-minute load fluctuations, flattens peak load while storage devices are charging, and discharges power back into the grid at later hours, as shown in **Figure 5.** PJM and the industry continue to research such impacts on the future grid's load shape and reliability. Likewise, PJM and the industry are also exploring how storage can mitigate IBR reliability attribute risks like frequency and other aspects of system stability.

[27] 2019 New Jersey Master Plan: Pathway to 2050 – https://nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf

[28] "Maryland passes energy storage pilot program to determine future regulatory framework" *Utility Dive* (2019) – https://www.utilitydive.com/news/maryland-passes-energy-storage-pilot-program-to-determine-future-regulatory/551769/

**Figure 5.** Impact of Storage on Peak Solar Production




## *2.2 Trends in Conventional Generation*

From 2012 through 2021, 41,211 MW of generation have retired in PJM (as discussed later in this paper), including more than 31,833 MW from 154 coal-fired units, 135 of which were more than 40 years old. Retiring units are being replaced by new generation, which previously consisted of new natural gas plants, but increasingly are renewable energy resources, as shown in **Figure 3** in **Section 2.1.4**. This generation shift, expected to continue through at least 2035, will impact the magnitude of grid expansion through 2035 and beyond.

### 2.2.1 Natural Gas-Powered Plant Trends

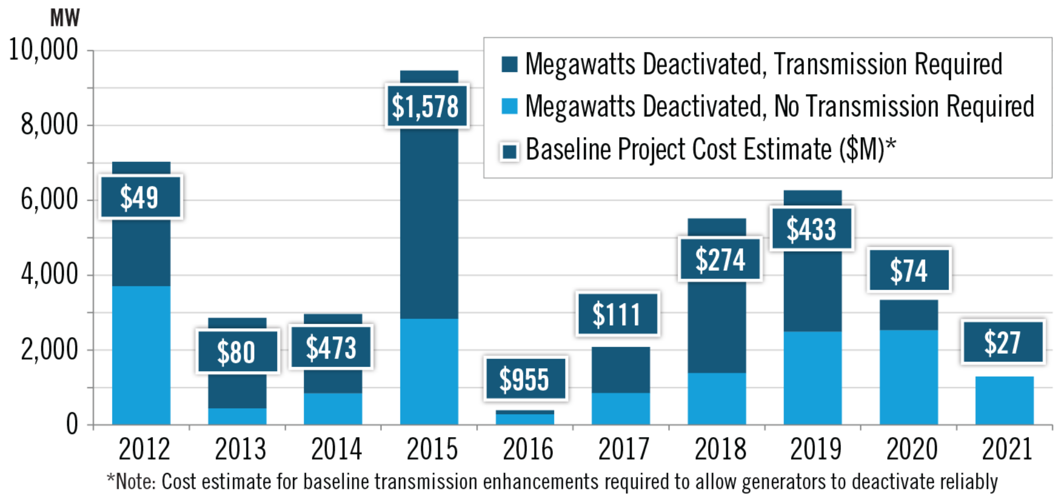
Currently, over 10,000 MW of new capacity powered by natural gas is seeking interconnection to the PJM grid, adding to more than 81,000 MW already in service. This capacity exceeded that powered by coal in 2016, marking an unprecedented shift in PJM's fuel mix and accounting for approximately 43% of PJM's installed capacity mix. Natural gas generation requests were a substantial percentage of the interconnection queue for several years, largely due to the availability of natural gas from the Marcellus and Utica shale gas deposits located in the middle of the PJM footprint. The shale gas development contributed significantly to the transition from coal between 2013 and 2018. Today, though, natural gas-powered units make up roughly 10% of interconnection queue requests on a CIR megawatt basis, as shown earlier in **Section 2.1.4**, **Figure 3.**

### 2.2.2 Generator Deactivations

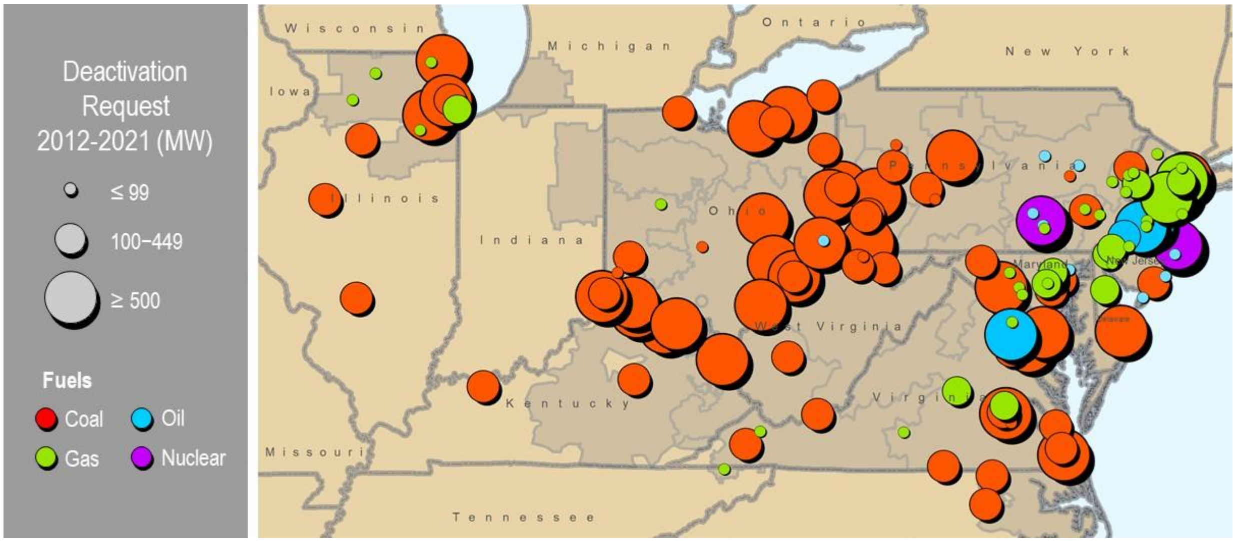
Generator deactivations alter power flows that can cause transmission line overloads and, given the loss of reactive power control capability from large-scale coal-fired and nuclear-powered generators, can undermine voltage control. When PJM receives a formal generator deactivation request, it conducts thermal and reactive studies to ensure that remaining generation continues to be deliverable to load. If criteria violations are identified, PJM develops a solution in coordination with affected transmission owners.

**Figure 6** summarizes, and **Map 11** shows, the 41,209 MW of deactivation request notifications[29] across all fuel types that PJM received from 2012 through 2021. Notifications totaling 24,507 MW have accounted for $4.1 billion of baseline grid enhancements to solve reliability criteria violations. The remaining 16,702 MW of deactivating generation did not cause reliability criteria violations, and thus did not require baseline transmission enhancements.

**Figure 6.** PJM Generator Deactivation-Driven Baseline Transmission Investment




**Map 11.** **PJ**M Deactivation Notification Requests, All Fuel Types, 2012–2021




Many factors can lead units to deactivate. Plant age and economic impacts of increasing operating costs are often key drivers. Other significant factors include environmental public policy, particularly with regard to carbon emissions.

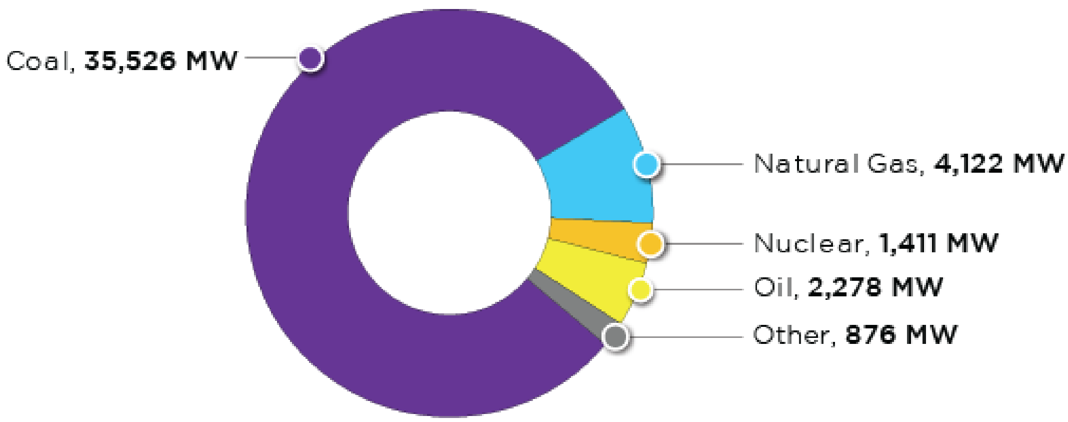
[29] The impact of generator deactivation requests that were subsequently withdrawn do not appear in **Map 11**, nor as part of megawatt values and baseline transmission dollar values.

Generator deactivations are both driven by and directly impact PJM capacity auction activity. For example, 10 coal-powered units did not clear the 2022/2023 Base Residual Auction conducted in May 2021. Nine of these units submitted notifications of deactivation in June 2021. The tenth unit that did not request deactivation exhibited strong energy and ancillary service revenue supported by expected strong operating periods. A major factor putting a generator at risk is its inability to clear a capacity auction given its costs compared to other resources offered into the auction:

- New entrants with more efficient performance, including those powered by Marcellus and Utica shale natural gas
- Wind- and solar-powered renewable energy resources with no marginal fuel cost
- Demand resources
- Energy efficiency programs

Such factors are driving the business decisions by owners to retire over 47,000 MW of generation between 2012 and 2021 as shown in **Figure 7.** Coal and nuclear deactivations account for 87% of the total.

**Figure 7.** Actual Generation Deactivation by Fuel Type, 2012–2021




#### 2.2.2.1 Coal-Powered Plant Deactivation

As **Figure 7** shows, coal-fired power plants account for 81% (over 35,500 MW) of total deactivations between 2012 and 2021 driven by one or more factors. Some larger coal units were located on or near now-depleted coal mines in order to reduce fuel transportation costs. To remain in operation, these plants sought more cost-effective sources for coal, increasing the fuel transportation component of their unit operating costs. For many other coal plants, environmental regulations, including those to reduce $NO_X$, $SO_2$ and $CO_2$ emissions under the Mercury and Air Toxics Standard (MATS) of 2011 and the Clean Power Plan of 2015, have increased unit costs driven by the need to install new emission control equipment.

#### 2.2.2.2 Nuclear-Powered Plant Deactivation

As **Figure 7** shows, nuclear power plants account for 3% (over 1,400 MW) of total generation retiring in PJM's footprint between 2012 and 2021. Original investment costs have put nuclear-powered units at risk in PJM's Reliability Pricing Model capacity auctions. Ongoing regulatory and engineering operating costs have put them at risk in energy markets compared to bids of units powered by other fuels. The potential for financial loss is amplified during operating conditions when they are directed to reduce their output below levels for which they were designed.

Unlike many older coal-fired generating plants, nuclear plants are carbon friendly. This aspect of their operation is drawing state-level attention with zero emission credits (ZECs). To that end, the financial benefit of ZECs have meant the withdrawal of deactivation notifications in 2019 and 2021 for seven nuclear plant deactivations totaling over 11,500 MW. ZECs are subject to periodic review and renewal and, like other public policy action, can have an impact on deactivation decisions.

Nuclear plants have rising operating costs but are kept in the market to ensure reliability and to satisfy decarbonization and other environmental public policy objectives. To the extent that nuclear plant operators can reap positive revenue streams, they will likely pursue relicensing. The Nuclear Regulatory Commission (NRC) staff has defined subsequent license renewal (SLR) to be an operating extension from 60 years to 80 years.[30] Nevertheless, PJM must face the reality that some or all of the nuclear plants within in its footprint could deactivate by 2050.

## *2.3 Impacts of Generation Shift*

### 2.3.1 Loss of Generator Reliability Attributes

PJM issued a white paper[31] in March 2017 to quantify the generator reliability attributes that contribute to grid reliability. As part of that paper, PJM examined information and data it compiled from: (1) various NERC forums that defined Interconnected Operations Services and Essential Reliability Services; (2) PJM renewable integration (energy transition) studies, ancillary service markets, the Capacity Performance Initiative, and the Advanced Technology Pilot program; and (3) PJM staff, stakeholders and other industry experts. The result was the generator reliability attributes summarized below in **Figure 8,** based on PJM operational experience with generating units powered by coal, natural gas (steam and combustion turbine), oil (steam and combustion turbine), nuclear, solar, wind and hydro, and with battery/storage and demand response.

[30] https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html

[31] PJM's Evolving Resource Mix and System Reliability. March 30, 2017. https://www.pjm.com/-/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx

**Figure 8.** Generator Reliability Attribute Matrix[32]

● = Exhibits Attribute
◒ = Partially Exhibits Attribute
○ = Does Not Exhibit Attribute

| | Essential Reliability Services (Frequency, Voltage, Ramp Capability) | | | | | Sustainability | | Flexibility | | | Other | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Frequency Response (Inertia & Primary) | Voltage Control | Ramp | | | | | | | | | | |
| Resource Type/ Rank | | | Regulation | Contingency Reserve | Load Following | Not Fuel Limited (> 72 hours at Eco. Max Output) | On-site Fuel Inventory | Cycle | Short Min. Run Time (< 2 hrs.)/Multiple Starts Per Day | Startup/Notification Time < 30 Minutes | Black Start Capable | No Environmental Restrictions (That Would Limit Run Hours) | Equivalent Availability Factor |
| **Hydro** | ● | ● | ● | ● | ● | ○ | ◒ | ● | ● | ● | ● | ◒ | ● |
| **Natural Gas – Combustion Turbine** | ● | ● | ◒ | ● | ◒ | ● | ○ | ● | ● | ● | ● | ◒ | ◒ |
| **Oil – Steam** | ● | ● | ● | ● | ● | ● | ● | ● | ○ | ○ | ○ | ○ | ◒ |
| **Coal – Steam** | ● | ● | ● | ● | ● | ● | ● | ◒ | ○ | ○ | ○ | ◒ | ◒ |
| **Natural Gas – Steam** | ● | ● | ● | ● | ● | ● | ○ | ● | ○ | ○ | ● | ◒ | ◒ |
| **Oil/Diesel – Combustion Turbine** | ● | ● | ○ | ● | ○ | ○ | ● | ● | ● | ● | ● | ○ | ◒ |
| **Nuclear** | ◒ | ● | ○ | ○ | ◒ | ● | ● | ○ | ○ | ○ | ○ | ◒ | ● |
| **Battery/Storage** | ◒ | ◒ | ● | ● | ○ | ○ | ○ | ● | ● | ● | ◒ | ● | ● |
| **Demand Response** | ○ | ○ | ◒ | ◒ | ◒ | ◒ | ◒ | ● | ● | ◒ | ○ | ● | ● |
| **Solar** | ◒ | ◒ | ○ | ○ | ◒ | ○ | ○ | ● | ● | ● | ○ | ● | ● |
| **Wind** | ◒ | ◒ | ○ | ○ | ◒ | ○ | ○ | ● | ● | ● | ○ | ◒ | ● |

The ability of generators to provide various reliability attributes will likely be driven by advances in technology and overall fuel mix. If PJM's actual future dispatch-stack fuel mix should evolve such that adequate levels of generator reliability attributes fall below the levels needed to maintain reliable grid operations, then additional operating procedures, market incentives and regulatory structures may be needed to maintain adequate levels. **Section 7** discusses PJM's future grid road map to address this challenge.

### 2.3.2 Addressing Inverter-Based Generator Characteristics

If current trends continue, PJM will continue to see more IBR wind and solar generation, which is expected to increase to 22% of PJM's fuel mix by 2035. By contrast, fewer conventional synchronous generators – primarily driven by coal and nuclear deactivations – will be available to provide essential NERC-defined reliability functions. Non-synchronous inverter-based generation is connected to the grid via inverters that utilize power-electronic devices to integrate the variable resources to the grid. A proliferation of IBRs can significantly impact reactive control, stability, short-circuit current, inertia and frequency control – all critical dimensions of future grid planning. **Section 7** discusses PJM's road map to address these future grid impacts.

[32] Ibid. page 16.

Additionally, as the Energy Transition in PJM white paper discussed earlier in **Section 2.1.3** indicated, IBRs may not be able to provide the same level of other essential, operationally focused reliability attributes as well: ramping, balancing control, flexibility and black start. That report speaks to their impacts and potential solutions; they are not addressed, per se, in this report.

# 3. Distributed Energy Resources

Distributed energy resources (DER)[33] are not new to PJM, nor to regional grid planning. Since its New Services Queue process began in the late 1990s, PJM has integrated DER that have included hydro, natural gas, landfill gas (methane), diesel, oil, waste, wood byproducts, storage, wind, solar and hybrid facilities. But, while PJM has integrated DER into its wholesale market, DER can also operate outside it and PJM's New Services Queue process. Accounting for approximately two-thirds of all DER interconnection requests, these non-wholesale facilities typically fall under state regulations (i.e., outside the jurisdiction of PJM's FERC-approved Tariff) and include the following:

1 | **Behind-the-meter generation (load reducer) –** This DER output offset load under owner's control; any excess power is not injected past the meter onto the distribution system.

2 | **Electric vehicles (EVs) –** Vehicles with battery storage capability can inject into or withdraw power from the distribution system in a controlled manner.

3 | **Backup generation –** Such generation can operate in islanded mode to serve owner's load during a distribution system outage.

4 | **Retail generation –** A distribution company, municipality or cooperative may develop such generation to serve their system load but does not inject power onto the transmission system.

5 | **Net metering –** Generation in excess of load is netted against that purchased off local distribution system over some defined period of time.

6 | **Storage as distribution system tool –** Installed by a distribution company, municipality or cooperative, this storage can absorb power and inject it onto local distribution systems when called upon.

While EV penetration levels will impact transmission and distribution systems as load, the focus in this section is on EVs as a potential distribution voltage level generation resource. **Section 4.1.1** of this report discusses anticipated future grid EV impacts on load shape and timing.

[33] As defined by FERC in 2016: DER is "A source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment."

## 3.1 DER Activity

DER interconnections have been growing steadily since 2009 and are expected to continue to grow over the next two decades. Currently, over 6,300 MW of distributed solar capacity is connected at the distribution level, as reported through PJM's Generation Attribute Tracking System (GATS). DER growth in PJM is due partly to state, local and federal policies but is also driven by environmental considerations, customer desire for self-supply, and declining costs for acquiring and implementing DER technologies.

PJM's Resource Adequacy Planning Department has published projections for further DER growth. By 2035, the current 2,300 MW of load reduction, due to non-wholesale DER, is projected to grow by more than three times to an estimated 8,000 MW. Some electric distribution companies have established public information vehicles that parties can use in developing DER on their systems.[34] Currently, FirstEnergy, Pepco and PSE&G have implemented web-based geographic information system map graphical displays of their respective DER development potential.[35]

#### 3.1.1.1 Public Policy Drivers

Federal and state policies are driving rapid growth of DER in PJM, as evidenced by the interconnection queue. PJM states have also adopted EV growth policies and battery storage pilots, which could drive additional future DER growth. Moreover, the Biden administration has set even more aggressive goals than PJM states to achieve a "carbon-free power sector" by 2035.[36] In addition to the clean electricity standard, the administration has also established goals to expand the EV market from 2.5% of cars in 2021[37] to 50% by 2030 – a penetration level that could impact transmission planning and operations, especially in densely populated areas like the eastern subregion of PJM.

Existing and newly proposed financial incentives could accelerate this target-driven growth. The federal government offers tax credits for renewables and some EVs, with more proposals (including possible clean energy program payments) making their way through Congress. When combined with possible state and local incentives for EVs and renewables (including tax abatement, grants, net metering, Renewable Energy Certificates and even state tax credits), the market could surpass target-driven growth projections in certain locations, especially where project capital and unused space are available.

Taken together, these policy drivers are yielding a number of potential future grid DER penetration scenarios, ranging from 10% to 50%, by 2030.[38] While quantitative analysis for predicting DER penetration by location may still be somewhat primitive, anecdotal data could contribute to qualitative analysis of a high-penetration DER future.

#### 3.1.1.2 Impact of FERC Order 2222

FERC Order 2222 enables DER, including non-wholesale DER, to participate in wholesale markets. Realizing the grid of the future will require PJM to implement changes in its planning process modeling and dispatch methods to consider future DER growth. Enhancements to the RTEP process will enable greater DER visibility and provide more

[34] California Public Utility Commission, R.21-06-017, June 24, 2021; p. 18.

[35] FirstEnergy: https://firstenergycorp.maps.arcgis.com/apps/webappviewer/index.html?id=d43cf2482a344e469eae6ca569403c24
Pepco: https://www.pepco.com/SmartEnergy/MyGreenPowerConnection/Pages/HostingCapacityMap.aspx
PSE&G: https://nj.pseg.com/saveenergyandmoney/solarandrenewableenergy/solarpowersustainability

[36] https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/

[37] https://insideevs.com/news/526699/us-electric-car-registrations-2021h1/

[38] https://www.pv-tech.org/renewable-energy-could-provide-33-50-of-us-electricity-by-2030-but-unlikely-to-hit-biden-80-target/

accurate alignment with operations and markets grid studies. The order allows aggregated non-wholesale DER to participate in wholesale markets. Overall, PJM will need to track three types: (1) wholesale DER; (2) non-wholesale DER still being netted; and (3) non-wholesale DER participating in wholesale aggregation. The need to explicitly model loads and DER generation will require careful tracking to avoid double counting.

PJM currently relies heavily on economic modeling of rooftop solar development and nets it out as part of the PJM load forecast. In reality, this essentially masks the actual total PJM load being served. While netting such solar DER against gross load may be adequate for now, this modeling approach may be inadequate to reliably plan the system under certain solar conditions as penetration levels grow. This issue is illustrated by a 2017 operational event in the North Carolina area of the Dominion Transmission Zone. A combination of facility switching and maintenance outages caused power on local 115 kV lines to exceed ratings when the setting sun reduced local DER solar output.

### *3.2 DER – Future Grid Impacts*

PJM's grid of the future road map must determine and examine the point at which DER growth actually causes reliability criteria violations. Doing so must consider the reality that DER fall into three categories: controllable, non-controllable and semi-controllable. Renewable resource output is variable and cannot be assumed to operate continuously. Such output is inherently non-controllable. Resources like storage and EVs are semi-controllable because once fully charged, they can no longer draw power from the grid. Likewise, once depleted, such devices can no longer inject power back onto the system. With growing DER deployment, PJM must be increasingly able to account for these characteristics as part of grid planning and operations.

With that in mind, PJM's analysis will evaluate the impacts of DER (including that from EV charging and discharging) on line-loading conditions as part of time-of-day studies in addition to peak load periods. Fundamentally, energy costs will influence human power consumption behavior, altering transmission flow patterns from historical norms.

## 4. Electrification Impacts on Load

### *4.1 Electrification Trends*

Electrification is the process of converting an end-use load that uses fossil fuels (or other non-electric energy sources) to electricity. This most commonly refers to vehicles, but can also refer to home and business uses for ambient heating, water heating, cooking and other activities. Transportation and heating could have the greatest impact on load forecast and load shape.

#### 4.1.1 Transportation Electrification

Transportation electrification will be a significant contributor to future demand. Electric vehicle purchases have been growing at an exponential rate yet still amount to less than 1% of light-duty vehicles in the PJM service area. As with any emerging technology, a significant degree of adoption-rate uncertainty always exists. Forecasts for EV sales range widely from 4% of total vehicle sales by 2030 and 8% by 2040,[39] to the recent White House EV target to reach 50% by 2030.[40] Ultimately, the pace of EV sales will fundamentally be driven by battery prices and government incentives.

[39] Outlook of the Energy Information Administration 2020 Annual Energy Outlook is the basis for the projections in the PJM 2021 Load Forecast.

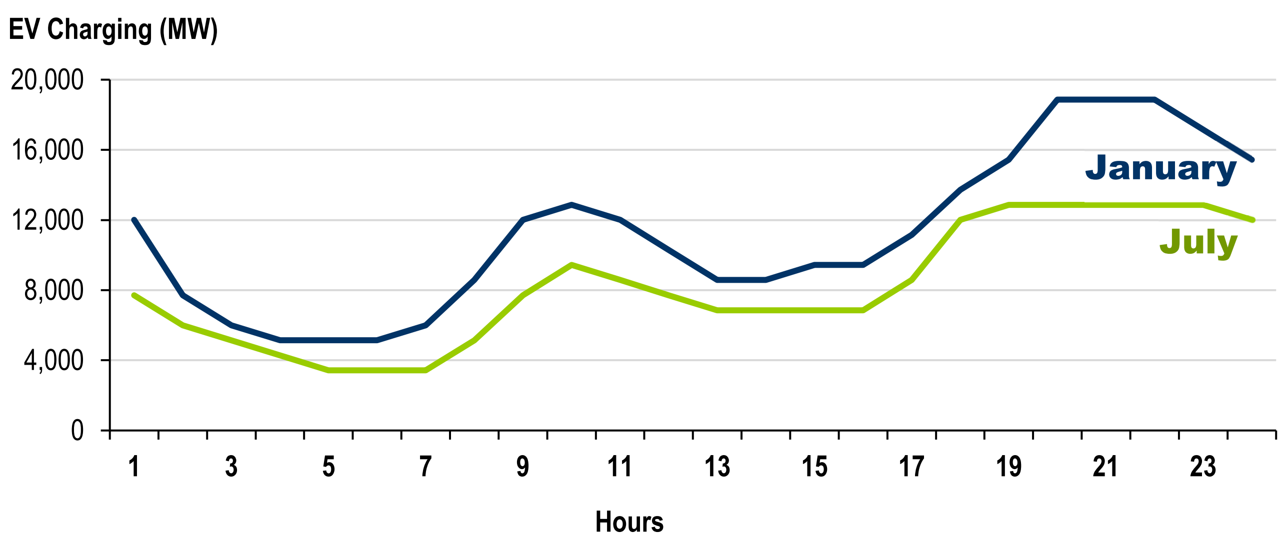
[40] https://www.whitehouse.gov/briefing-room/statements-releases/2021/08/05/fact-sheet-president-biden-announces-steps-to-drive-american-leadership-forward-on-clean-cars-and-trucks/

Industry research[41] currently shows a tendency for EV owners to charge the most at home during evening hours. An ISO New England (ISO-NE) study revealed weekday patterns feature two charging behavior ramps: first in the morning when drivers get to work, and then in the evening when drivers get home. The ISO-NE study also showed that charging needs are higher in winter months, which they attributed to the dual effects of automobile cabin heating and reduced battery performance at low temperatures.[42]

At current EV penetration levels in the PJM region, this is inconsequential, amounting to an estimated peak contribution of several hundred megawatts. However, if EVs represented one-third of light-duty vehicles, as they likely would if the White House target is met, then impacts to peak loads could be considerable. Winter peak impacts could amount to 19 GW, and summer peak impacts could amount to 13 GW, as shown in **Figure 9**. As EV penetration grows even further – to one-half or more of total vehicles – then the potential impacts would be magnified.

Research has shown that EV demand can be flexible if properly incentivized. Some utilities within the PJM region have already begun to implement time-of-use rates or peak/off-peak pricing. As EVs become more prevalent, these strategies and perhaps others, such as demand charges or load response programs, are very likely to become more commonplace. A successful strategy would shift charging into overnight and midday hours, significantly blunting peak load and, consequently, the resource adequacy impact of additional EV penetration.

**Figure 9.** Example Weekday Charging Under Vehicle Electrification Scenario Based on Current Behavior[43]




[41] NREL study on "Electric Vehicle Charging Implications for Utility Ratemaking in Colorado" (https://www.nrel.gov/docs/fy19osti/73303.pdf) and EV profiles in the "2021 Final Transportation Electrification Forecast" from ISO New England (https://www.iso-ne.com/static-assets/documents/2021/04/final_2021_transp_elec_forecast.pdf)

[42] https://www.iso-ne.com/static-assets/documents/2019/11/p2_transp_elect_fx_update.pdf

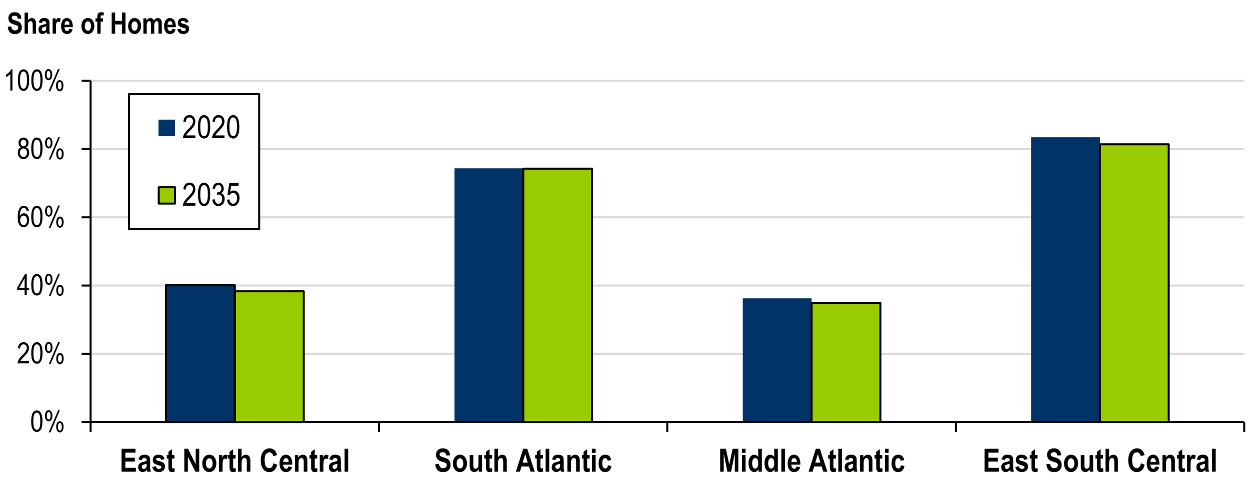
[43] State incentives would be expected to alter these curves to drive desired off-peak charging behavior.

### 4.1.2 Building Heating Electrification

The outlook for building heating is more uncertain than that for EVs. General consensus holds that future EV penetration levels will be significantly higher than today, but the uncertainty centers on quantifying the magnitude of that growth. This is not the case with electric heating.

In PJM's 2021 Load Forecast, which used input from the 2020 Energy Information Administration Annual Energy Outlook, electric heating does not gain traction. **Figure 10** shows the percent level of homes forecast to have electric heating in each PJM sub-region by 2035. Given current policy and costs, the direction tends to be more toward natural gas heating in much of the PJM service area. Some areas in PJM's southern subregion already rely on electricity to some degree for heating (e.g., Virginia). However, northern Midwest and mid-Atlantic areas of PJM predominately use non-electric fuels (mostly natural gas and some propane and fuel oil).

**Figure 10.** Residential Electric Heating* Share of Homes[44]




**Electric heating here is defined as electric furnaces, heat pumps (air-source and geothermal), and secondary heating elements.*

In New England, states are incentivizing greater adoption of electric air-source heat pumps to help meet decarbonization goals[45] by offering significant rebates to replace gas equipment with electric heat pumps.[46] This is in contrast to some states in the PJM service area, which still have incentives for purchasing new natural gas furnaces. A sea change on the public policy front would be needed to bring about large-scale increases in electric heating in the PJM footprint.

If such a policy change was to be implemented, the impacts to the load would be considerable. From a geographical perspective, the largest impacts would be to those regions that are not already pursuing electrification: primarily the mid-Atlantic and northern Midwest areas of PJM's service area.

[44] Data comes from Itron through analysis of data from the EIA Annual Energy Outlook. Geographic definitions correspond to U.S. Census Bureau defined divisions, which are East North Central (IN, IL, MI, OH, WI), South Atlantic (DE, DC, FL, GA, MD, NC, SC, VA, WV), Middle Atlantic (NJ, NY, PA), and East South Central (AL, KY, MS, TN).

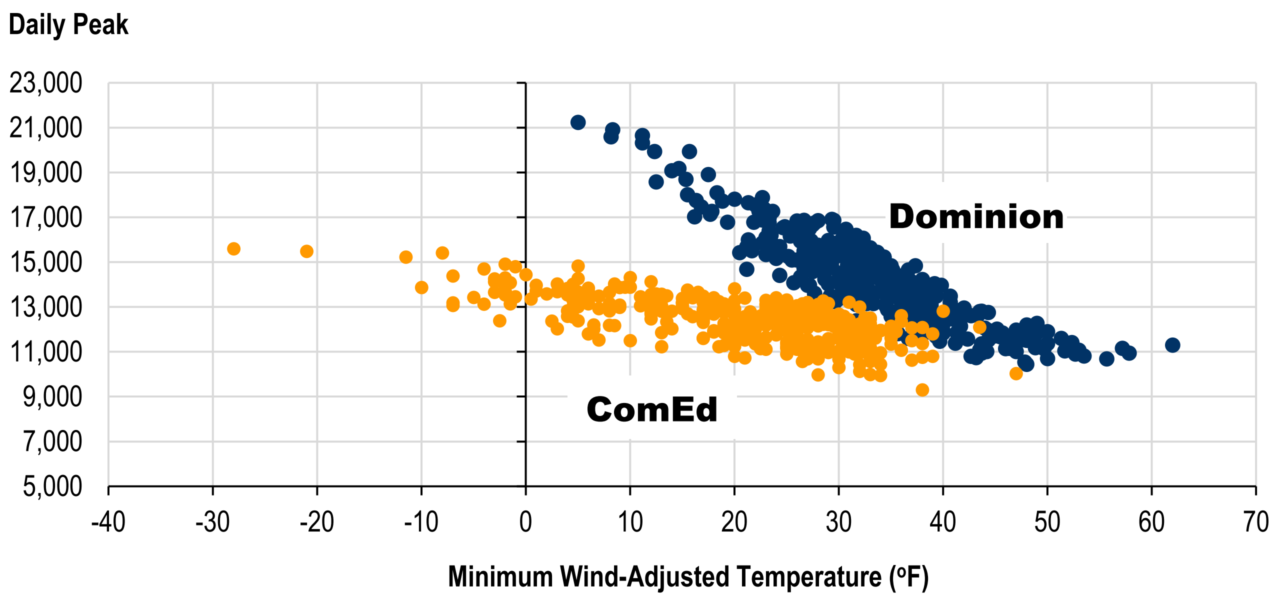
[45] ISO-NE "Final 2021 Heating Electrification Forecast" (https://www.iso-ne.com/static-assets/documents/2021/02/lfc2021_final_heating_elec.pdf).

[46] Massachusetts heat pump rebate program: https://www.masssave.com/en/saving/residential-rebates/heat-pump

For example, consider two similarly sized transmission zones: Commonwealth Edison (ComEd) and Dominion. The ComEd Transmission Zone is summer-peaking while the Dominion Transmission Zone is winter-peaking by a small margin (but in any given year could be summer- or winter-peaking), as shown in **Figure 11**. Customers in the ComEd Zone primarily use natural gas for heating, with little reliance on electricity; roughly 2% of homes use heat pumps. Customers in the Dominion Zone primarily use electricity for heating, with more than 50% of homes using heat pumps. The ComEd Zone sees minimum daily wind-adjusted temperatures that commonly dip below zero degrees, while the Dominion Zone only experiences temperatures below 20 degrees on a couple of days.

Based on this information, if the Dominion Zone was to experience typical ComEd weather, load levels at 25,000 MW or more could be experienced. This may be mitigated to some degree if homes have backup heating like gas furnaces, which is more likely in colder climates, adding another layer of uncertainty.

**Figure 11.** Dominion and ComEd Winter Daily Peak Loads Since December 2017




## 4.2 Electrification – Future Grid Impacts

In the event that the White House EV target of 50% of light-duty vehicle sales by 2030 is met, accelerated sales could lead to EV charging that would account for approximately 10% of total RTO energy in the next 15 years and then grow further. Demand impacts could be similar given current charging behavior, if public policy remains unaltered. However, given the growing availability of time-of-use rates, the impact could likely be mitigated to some extent. Reaching that target is also likely to have a higher impact on winter peaks than on summer peaks for two reasons: (1) additional EV charging needs in winter vs. summer; and (2) a flatter winter load shape.

If EV charging is done optimally, it can fill in daily load-shape valleys. During the summer, this primarily means overnight and some midday hours to take advantage of both behind-the-meter and front-of-the-meter solar installations. In the winter, load valleys are shallower, but EV charging also impacts peak load levels.

As described earlier, heating electrification is not considered in PJM's current baseline load forecast. To consider the potential impacts, a plausible scenario must be developed using baseline projections from the EIA that are modified to represent a move of new heating equipment purchasing toward electric heat pumps rather than natural gas furnaces.[47] As a result, because of the current combination of high proportions of natural gas furnaces and low proportions of heat pumps in the Middle Atlantic and East North Central census areas within PJM, this scenario will have a higher impact there than in the South Atlantic and East South Central census areas within PJM where the reverse is true.

For perspective, **Figure 12** shows current PJM summer- and winter-peak load profiles. **Figure 13** shows examples of net-load peak shapes for summer and winter, respectively, under a heating electrification scenario before taking into account EVs. Depending on the degree to which the level of electric heating increases, the gap between winter and summer peaks would narrow with PJM potentially becoming a winter-peaking system. Winter peaks are made even more likely in this scenario once EV charging needs are layered on top.

**Figure 12.** PJM Current Summer and Winter Peak Profiles, Per-Unit Basis (Peak = 1.0)

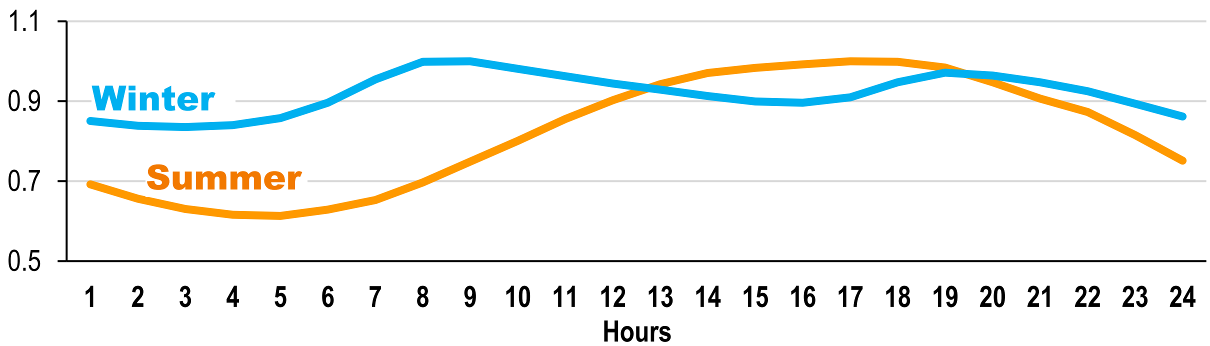
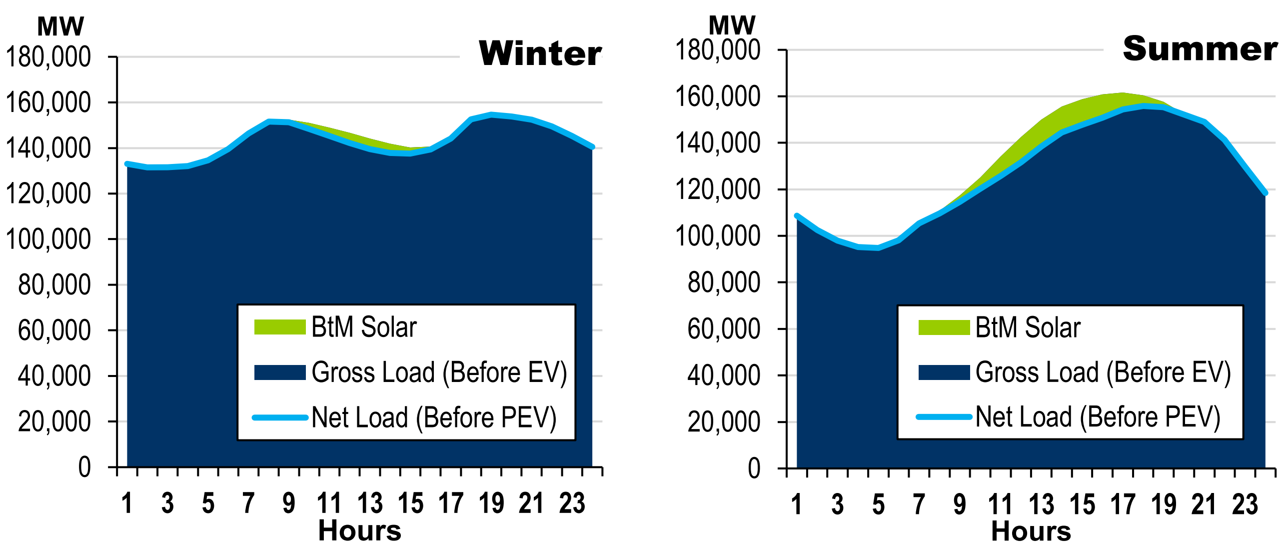



**Figure 13.** Potential Future Winter/Summer Peak Day Under Scenario Before EV Charging




In **Figure 14**, EV charging is added to the net load shapes for summer and winter peaks. Two EV charging scenarios are shown:

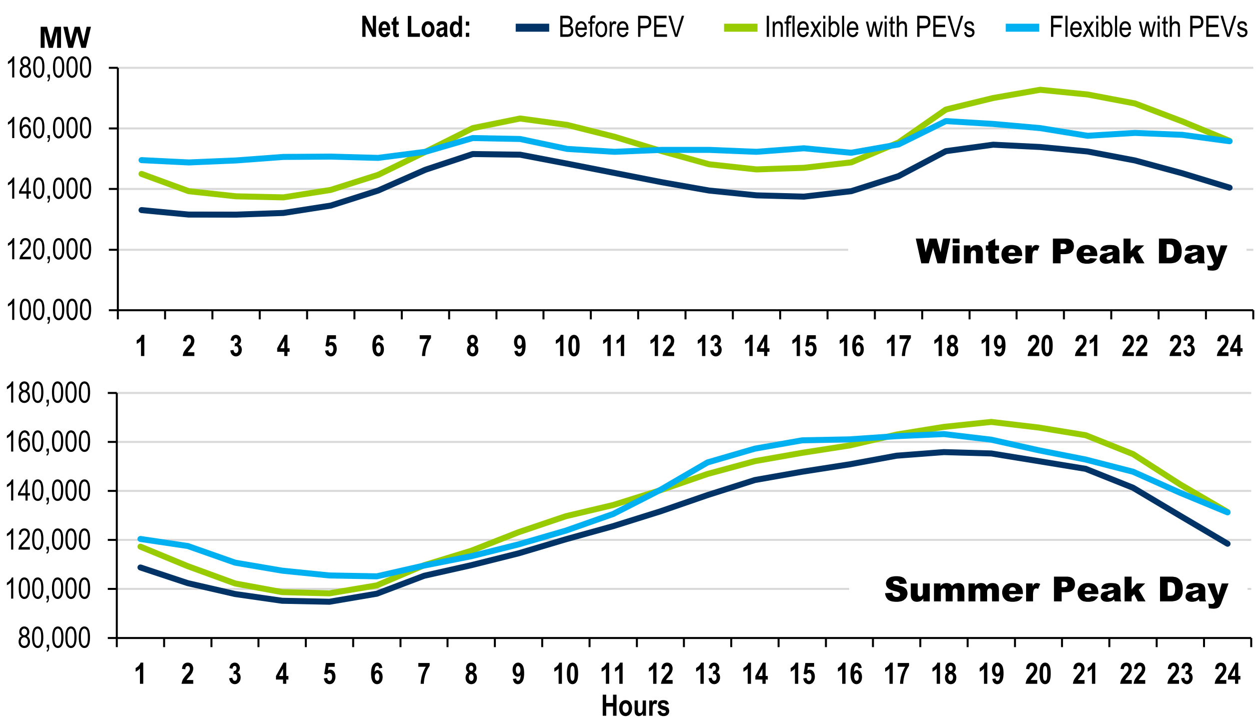
[47] New heating units are a function of: (1) aggregate increases in total heating; and (2) replacement of obsolescent heating. Assuming an average lifetime of 17.5 years for a natural gas furnace, these two factors amount to approximately 4% of households obtaining new furnaces per year in the mid-Atlantic and east-north-central areas of PJM and a little less than 2% of households in the south Atlantic and east-south-central areas of PJM. PJM assumes that 10% of these new units will be electric heat pumps rather than natural gas furnaces.

**Inflexible –** charging behavior observed today that is also expected in the future

**Flexible –** charging behavior modified such that it shifts somewhat to off-peak load

This would mean that under a scenario that incorporates winter EV charging flexibility, peak-saving benefits do reach a limit. Once a certain amount of EV load on the system is reached, additional EV load has fewer places along a daily load curve on which to move, becoming increasingly difficult to avoid adding to a daily peak. In the summer, given the relatively deeper overnight valley, considerable room still exists to add EVs without necessarily impacting peak load significantly.

**Figure 14.** Potential Future PJM Winter and Summer Peak Day Under PEV[48] Scenario




# 5. Emerging Transmission Grid Technologies

## *5.1 Increasing Transmission Capability*

Applying emerging technologies in new ways will play a growing role in realizing PJM's grid of the future. The generation shift discussed in **Section 2** will alter how power flows across the region PJM serves as the interconnection of substantial levels of renewables at many locations will replace the deactivation of large-scale, centralized coal-fired and nuclear-powered generation at different, existing locations. This will drive future grid expansion to ensure reliable power delivery to load centers. Indeed, within the PJM footprint, as noted earlier in **Section 2.1.3**, an estimated 105,000 MW of new renewable resources will interconnect to the PJM grid by 2035, much of which will be less than 100 miles from the load centers being served, as discussed in **Section 2.1.1.**

The grid expansion technology needed to deliver power will not be limited to conventional greenfield (and often multi-state) transmission lines, which are increasingly more difficult to site and permit. Emerging technologies that will

[48] PEV is an acronym for plug-in electric vehicle and is used synonymously with "EV."

continue to play a growing role include dynamic line ratings, special conductors, tower configurations and other technologies, and are summarized below and described in more detail in PJM's 2021 Regional Transmission Expansion Plan, Section 1.3.5., and in the white paper Reliability in PJM: Today and Tomorrow.

**1 |** **Dynamic line rating (DLR) technology** can identify additional capacity on transmission lines, potentially relieving congestion and creating economic efficiencies. Such technology can also enhance system resilience by providing enhanced real-time monitoring of transmission assets.

**2 |** **Advanced conductor designs** can provide a means of achieving a higher ampacity transmission line capability on existing corridors, mitigating the need for new lines or significant rebuild. Developers that build new transmission lines, or rebuild existing ones, often encounter siting and permitting challenges that can cause lengthy delays or even prevent project construction altogether. Other advanced conductor design incorporates the use of special conductor coatings that have a higher emissivity and lower absorptivity, which leads to cooler conductors and, thus, higher ampacity ratings.

**3 |** **Advanced transmission tower configuration technology** can provide a means to enhance the utilization of existing and new transmission line corridors as part of future grid expansion. Such designs, coupled with low-impedance bundled conductors, reduce line losses and significantly increase power delivery capability while avoiding the complexities and costs of series compensation.

**4 |** **Flexible alternating current transmission systems** (FACTS) are power system devices that take more conventional power system components – capacitors and reactors – and integrate them in various configurations with intelligent power electronics, high-speed thyristor valve technology and voltage-sourced converter (VSC) technology. FACTS devices can directly support additional transmission line power flow with reactive power injections at their point of interconnection and can indirectly control power flow by modulating transmission line impedances. The most common FACTS devices include static VAR compensators (SVCs) and static synchronous compensators (STATCOMs).

**5 |** **SVC hybrids** are a new type of FACTS device that combines the reactive support of a traditional STATCOM with the real power support of energy storage. The purpose of an SVC hybrid is to level-out power fluctuations from variable generating resources, such as wind and solar, by employing the SVC hybrid's grid-forming inverter enabled by the active power control of its energy storage. A grid-forming inverter functions to "go first, not follow" existing grid conditions to try to establish desired power levels and quality.

PJM remains neutral with respect to grid-enhancing technologies that are part of proposals submitted in RTEP windows or as part of transmission owner supplemental projects. To the extent submitted as part of a competitive RTEP window, PJM evaluates qualifying grid-enhancing technology proposals in a manner that is not materially different than the way it evaluates other project proposals. PJM examines the impact of a technology's characteristics on solving identified reliability and market efficiency needs efficiently or cost-effectively. Further, PJM evaluates whether a proposal that includes the deployment of a grid-enhancing technology requires any changes to telemetry, modeling and other operating tools or protocols to support and accommodate integration from a PJM markets and operations standpoint.

## 5.2 Electric Vehicles

PJM continues to pay close attention to U.S. transportation sector electrification and, in particular, the impact of EVs on transmission system needs. The Edison Electric Institute estimates that EVs will grow from 1 million today to 7 million across the country by 2025.[49] The report goes on to cite the Northeast as one of the regions of the country "with higher concentrations of first adopters of electric vehicles and more immediate, more ambitious policy targets."[50]

From a future grid perspective, PJM load forecasting processes must ensure that EVs are accounted for in charging mode, and transmission planning studies must account for the bus loads associated with charging stations. EVs may also be in a position to provide grid reliability services like regulation vis-à-vis their on-board battery storage capability if public policy economic incentives can drive desired customer behaviors.

## 5.3 Microgrids

Microgrid control technology, coupled with distributed energy assets, has the real potential to improve grid resilience, security, reliability and efficiency. Microgrids are small clusters of energy assets and loads that are controlled to achieve a variety of benefits for the owner/operator. One of the primary benefits of building a microgrid is the ability to provide reliable electric power during significant electric grid disturbances, such as storm outages. PJM continues to work with industry partners, universities and states to better understand how microgrids can impact the grid in a positive way and how they can derive value from the PJM wholesale markets.

## 5.4 Storage as a Transmission Asset

Energy storage development continues to grow in PJM and other RTOs. As solar generation increases in PJM, growth of storage is expected to follow. Storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. To that end, PJM continues to pursue process improvements to permit storage as a transmission asset (SATA).

### 5.4.1 SATA Applications

Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, DOE national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

Queued storage resources currently total over 34,000 MW of interconnection requests for CIRs. These resources are anticipated to provide significant grid benefits given their ability to "firm-up" otherwise variable resources by charging and discharging to serve load at any given point in time. In addition to storage projects that interconnect as a resource seeking participation in PJM markets, storage may also serve as a transmission solution to address identified planning needs. Nonetheless, PJM's planning process must account for limited duration of each SATA installation, which could deplete itself and become unable to mitigate the violation, for which it was designed, when called upon to do so. To that end, and given that PJM is the regional transmission planner as designated by FERC,

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[49] "The Coming Electrification of the North American Economy: Why We Need a Robust Transmission Grid": https://wiresgroup.com/new/wp-content/uploads/2019/03/Electrification_BrattleReport_WIRES_FINAL_03062019.pdf.

[50] Ibid.

PJM will not deploy SATA to mitigate violations identified for baseline reliability and market efficiency unless compliance with standards, manuals and governing documents are strictly met.

### 5.4.2 State Public Policy Drivers

Storage development is also being driven both explicitly and implicitly by state policy objectives. Explicit state targets include Virginia's 3,100 MW of storage by 2035 and New Jersey's 2,000 MW target by 2030, as outlined in its 2019 Energy Master Plan. Maryland also has an energy storage pilot program that was implemented in 2019 to develop storage capacity within the state. Implicitly, storage is being developed as a complement to the influx of renewable resources driven by state RPS targets.

# 6. Resilience

## *6.1 Enhanced Reliability for Tomorrow's Grid*

A resilient grid must be able to withstand large-scale system disturbances, to which it is difficult to attach probabilities and that can exceed conventional NERC planning N-1-1 and N-1 planning criteria. High-impact, low-frequency contingencies – encompassing generation, transmission or both – can significantly impact PJM's ability to serve load reliably and maintain overall system integrity. Growing reliance on greater levels of variable resources raises resilience concerns, as the winter weather impacts of February 2021 on ERCOT, SPP and MISO demonstrated.

A number of emerging system conditions already present challenges to reliable system operations:

**1 |** Extreme weather

**2 |** Cyber and physical attacks

**3 |** Generation fleet shift driven by natural gas and increased deployment of renewable resources

Such challenges will continue to stress future grid resilience, which enhanced reliability criteria must address. For decades, planning criteria have been developed and applied to power systems across the country (and around the world) to ascertain the need for grid enhancement, so that system operators can meet the operating conditions they encounter on any given day. Planners test the system under simulated stressed conditions, such as extreme weather, to understand where reinforcements may be warranted to make the grid reliable.

## *6.2 Reliability and Resilience*

While resilience and reliability both define what it means for PJM to keep the lights on under a broad range of conditions, the concepts are not identical. PJM already complies with established NERC, regional and transmission owner reliability standards. To that end, PJM conducts its planning studies under critical, stressed conditions, so that system dispatchers can manage the actual system conditions on any given day in real time. Resilience takes this to another level, addressing challenges and emerging risks that existing reliability standards do not fully capture, such as:

1. Maintaining reliability in the face of significant events beyond typical planning criteria
2. Evaluating threats as part of the transmission planning process
3. Slowing disruptive events, mitigating their impacts and quickly recovering essential functions
4. Protecting essential systems based on assessed risks and hazards
5. Improving grid flexibility and control to adapt efficiently and quickly to post-event conditions
6. Addressing heavy reliance on one resource type

Planning for the grid of the future must consider all of these dimensions of resilience.

## 6.3 Beyond NERC Transmission Standards

Existing NERC planning criteria are structured around likely events, requiring that the bulk power system be tested for such contingencies as the loss of a transmission line (a high-probability, low-impact event) under the assumption that all other transmission facilities are in service. Yet in reality, dozens of facilities are out of service on any given day. PJM also simulates more severe, lower-probability "N-1-1" events like the loss of two circuits on a common tower line or a fault on a circuit followed by a breaker failure.

NERC standards address resilience to a degree. Existing planning standards require examination of the impact of extreme events such as the loss of an entire substation or the loss of an entire right-of-way – caused by a landslide, tornado, hurricane or fire, for example – that would take out multiple transmission lines at one time. Although an assessment of the impact of these events is required, reinforcement for these high-impact, low frequency events is not required under current NERC criteria. Planners must now also assess whether the transmission system is sufficiently reinforced to address extreme events like these as well those caused by physical and cyberattacks.

## 6.4 Reliability Criteria for Extreme Events

PJM's ongoing efforts are taking a forward-looking, holistic and proactive approach to plan for future transmission needs with respect to extreme events, which may become a more significant grid expansion driver under higher levels of renewable penetration. The scope of planning studies will support efforts to assess how extreme events can be analytically evaluated and how consequential impacts to system reliability are identified. This may lead to new reliability criteria and planning tests. To that end, PJM continues to work with stakeholders to consider planning process policy changes that may be needed to enable it to identify and plan needed transmission to address extreme events. PJM, in its ANOPR comments (noted earlier in the Executive Summary), has urged FERC to adopt a common definition of resilience and a specific resilience planning driver for grid enhancements, applicable to all planning entities.

## 6.5 Fuel Assurance

Resilience also encompasses fuel assurance – the ability of PJM to withstand disruptions to power output caused by the availability of fuel, ranging from natural gas pipeline delivery to weather-based restrictions on renewable resources. The 2014 Polar Vortex event demonstrated the exposure of gas-fired generation to pipeline delivery constraints as did the impacts of the February 2021 arctic event on ERCOT, SPP and MISO.

Solar and wind generator availability is characterized as variable insofar as output is impacted by both weather and time of day. Wind generation may be forced to shut down during periods of high winds to protect equipment. Such generators are designed with cut-out speeds of approximately 55 mph. The opposite conditions also present fuel-assurance concerns, including loss of wind-powered generation under severe, windless heat spells.

## 6.6 Loss of Transmission

Extreme weather, such as hurricanes and derechos, can force out significant portions of the transmission system, and the generation connected to it, for days. This could also happen under a geomagnetic disturbance, which is a space-weather phenomenon during which the grid can be exposed to quasi-DC-induced currents. These currents cause grid elements like transformers to overheat, necessitating their preemptive removal from service.

Additionally, NERC's CIP-014 standard requires transmission owner assessments to identify critical facilities that, if rendered inoperable, would cause instability, uncontrolled separation or cascading outages. Concerns across the industry about grid security and resilience under the outage of such facilities continues to grow. PJM's future planning must include efforts to eliminate current vulnerabilities for CIP-014 critical infrastructure, while also working to develop RTEP process criteria to avoid and mitigate the same risk for future critical infrastructure.

# 7. PJM Grid of the Future Road Map

## *7.1 Four Areas of Focus*

Each of the preceding sections for this report discussed grid of the future impacts for PJM RTEP process drivers. Those impacts are the impetus behind the road map presented here, comprising four focus areas:

| | | | |
|---|---|---|---|
| **1.** Transmission build-out scenario studies | **2.** Targeted reliability studies | **3.** RTEP process enhancements | **4.** Regulatory policy outcomes |

PJM discusses each focus area below in terms of current status and road map to meet future grid challenges.

## *7.2 Transmission Build-Out Scenario Studies*

Transmission build-out scenario studies will be conducted in 2022 based on power-flow case alignment with PJM's Energy Transition in PJM white paper and additional renewable integration studies, and leveraging analysis work of the OSW Scenario Study Phase 1. This OSW study phase considered multiple offshore wind injection scenarios as well as the renewable resources needed to meet state RPS onshore wind objectives. As PJM continues its initiatives to enable a decarbonized grid, additional analysis beyond the OSW scenario studies will examine an accelerated renewable penetration case, including a more in-depth assessment of the impacts from higher levels of building and transportation electrification.

The heart of RTEP grid of the future scenario studies to be conducted in 2022 will focus on identifying reliability impacts in terms of both transmission planning and resource adequacy. These scenario studies are not starting from scratch. To the contrary, as discussed above, they are building on foundational studies that have preceded them, including the energy transition analysis and OSW study efforts discussed earlier.

Scenario studies will examine the need for additional grid expansion driven by the location of retiring capacity (primarily coal and nuclear) relative to capacity replacement (natural gas and renewables), and the load centers they serve. These studies will employ generator deliverability methodologies to identify NERC and regional reliability criteria violations under test conditions that include summer peak, winter peak and light-load system conditions, as well as time-of-day conditions given the intermittency of renewables. The studies will focus on impacts to the bulk electric system where the impacts might lead to the rebuild of existing, or construction of new, grid infrastructure.

### 7.2.1 Renewables Penetration – Case Alignment With Ongoing Studies

PJM is adopting the approach used by the ongoing energy transition analysis and OSW study, discussed earlier in **Section 2.1.3** and **Section 2.1.6,** respectively. The energy transition studies are modeling installed capacity by resource type for each case based on RPS, state and corporate policy goal assumptions. Policy and Accelerated cases are employing a profitability assessment to identify candidate units for retirement, primarily coal-fired plants.

### 7.2.2 Modeling Generator Deactivations

As discussed in **Section 2.2.2**, conventional generation retirements are expected to continue, driven by the economics of unit age and environmental public policy. Deactivation studies typically examine how generator deactivations alter power flows that can cause transmission line thermal overloads and, given reductions in system reactive support from those generators, can undermine voltage control. In order to ensure alignment with renewable integration studies, grid of the future planning studies will employ the same methods to determine the generation to be modeled out-of-service in power-flow simulations. In summary, PJM planners will adopt the three deactivation categories developed as part of PJM's energy transition analysis:

**1 |** Formal deactivation notices – these retirements were included in all markets scenarios.

**2 |** State or utility policies or agreements that include shutdown of coal and oil generation, in addition to units that have formally submitted deactivation notices to PJM – these retirements were also included in all scenarios.

**3 |** Unit-specific retirements for capacity replacement – these retirements were included only in the Policy and Accelerated cases in order to offset the additional capacity being added by the renewable build-out.

To generate the list of candidate units to retire, each was ranked from most to least likely to retire based on an algorithm that looked at: (1) simulated profit and loss using production cost simulation; and (2) fixed-cost assumptions for coal- and nuclear-powered units. Resources were retired from this profit-loss list based on an amount equivalent to the renewables added. For the incremental amount of renewable resources added in each scenario, the value of these resources was determined through ELCC in unforced capacity (UCAP) terms. This capacity value was used as a target for total megawatt value of retirements in the power-flow case of each scenario.

### 7.2.3 Identifying Need for Grid Expansion

The heart of RTEP future grid scenario studies to be conducted in 2022 will focus on identifying reliability impacts in terms of both transmission planning and resource adequacy. These scenario studies are not starting from scratch. To the contrary, as discussed above, they are building on foundational studies that have preceded them, including Energy Transition analysis and OSW study efforts.

Scenario studies will examine the need for additional grid expansion driven by the location of retiring capacity (primarily coal and nuclear) relative to capacity replacement (natural gas and renewables), and the load centers they serve. These studies will employ generator deliverability methodologies to identify NERC and regional reliability criteria violations under test conditions that include summer peak, winter peak and light-load system conditions, as well as time-of-day conditions given the intermittency of renewables. The studies will focus on impacts to the bulk electric system where the impacts might lead to the rebuild of existing, or construction of new, grid infrastructure.

## *7.3 Targeted Reliability Studies*

Targeted reliability studies will build on 2022 scenario study results in order to evaluate generation and transmission reliability attributes, such as reactive control, stability, system inertia and frequency control, and short-circuit impacts, to ensure grid reliability.

The scenario studies described above make up just one area of future grid reliability evaluation. PJM's generation shift from large coal and nuclear plants to utility-scale renewables at new locations, more numerous than those of the generators they replace, will necessarily drive grid development. The ability of new, natural gas-fired generating units to replace reliability attributes (inertia, voltage support, frequency response, short-circuit current, etc.) lost by coal and nuclear unit deactivations will depend significantly on their location. Operability issues can arise in areas where sufficient levels of those attributes are not readily accessible. As a result, targeted reliability studies that examine them are also a necessary component of PJM's grid of the future road map.

Operability issues can arise in areas where sufficient levels of those attributes are not readily accessible. As a result, targeted reliability studies that examine them are also a necessary component of PJM's grid of the future road map, as discussed below. Detailed planning will be required to reduce the risk of operability issues and ensure resilience under extreme events:

1 | **Reactive Control** – As discussed earlier, voltage that is too low or too high can become a serious reliability issue and is dependent on the availability of resources – both generation and transmission – to produce or absorb reactive power. To the extent that PJM's generation resource mix does not provide the necessary minimum and maximum reactive capability to maintain adequate steady-state system bus voltages, then reliance on other reactive control devices will be required.

2 | **Voltage Instability** – This type of post-disturbance system response is defined as the point in power system operation beyond which no amount of reactive power injection will raise system voltages to pre-disturbance steady-state levels. Such voltage instability can cause power system voltage collapse if the post-disturbance equilibrium voltage is below acceptable limits. Under such conditions, system voltage can only be adjusted by reactive power injections until sustainable system voltage levels are restored. Voltage stability studies will guide the determination of system conditions and locations where such injections will be critical to maintaining grid reliability.

3 | **Dynamic Stability and Subsynchronous Resonance** (SSR) – System stability risk severity can increase as conventional generation deactivates (e.g., coal- and nuclear-powered units) in one area and is replaced with renewable IBR generation clustered in another area, particularly if those units are not near load centers. Such circumstances are aggravated by the fact that IBRs are non-synchronously connected to the grid via inverters and associated power electronics, often in geographical areas characterized by less tightly networked system topologies. PJM's grid of the future road map must encompass sophisticated and more granular studies and study techniques to identify potential unstable system conditions so that grid enhancements are developed to: (1) dampen potential instability that could otherwise cause cascading blackouts; and (2) mitigate SSR conditions that could cause turbine torsional stress and damage to conventional synchronous machines.

4 | **Inertia and Frequency Control** – This can be a concern in a grid with a high penetration of renewables, as it may result in a faster and larger frequency decline following a system disturbance because of a reduced level of reliance on generators with large rotating masses. Because non-synchronous generators like wind and solar are connected to the grid via inverters, they do not inherently provide natural inertial response for grid frequency control. NERC requires PJM, as a planning coordinator, to conduct an under-frequency load-shedding study. In the future, PJM will need to consider how to incentivize inertial frequency response that may become necessary to ensure an adequate supply on the system at all times and appropriately compensate those resources.

5 | **Leverage EIPC Frequency Response Task Force (FRTF) Results –** The Eastern Interconnection Planning Collaborative (EIPC) FRTF conducts a frequency response study every two years to evaluate the five-year-out future Eastern Interconnection. PJM must continue its participation in EIPC's frequency study project that is focusing on developing sound, near-term frequency study cases and developing a detailed plan for a long-term frequency study.

6 | **Short-Circuit Current Studies** – Specific studies will be required that evaluate reliability issues when insufficient short-circuit current exists under the proliferation of IBRs. These units produce less short-circuit current to trigger protective device response. Conventional protection systems are designed for large fault currents from synchronous and induction machines. Reduced short-circuit current could mean that circuit breakers may not clear faults in sufficient time, if at all, to prevent equipment loss and system instability.

7 | **Interregional Coordination** – Future planning must also address the need for greater interregional transmission expansion to address extreme events under a high penetration of renewables, the loss of which could impose the need for greater transfer capability to import power to serve load.

8 | **CIP-014 Analysis** – Planning must include efforts to eliminate existing CIP-014 vulnerabilities and incorporate criteria to mitigate CIP-014 risk in future infrastructure, as described in **Section 6.6**.

9 | **Natural Gas Availability** – PJM must continue to ensure the ability of the grid to withstand the loss of natural gas-fired generation output caused by natural gas pipeline delivery disruption. Previous cold weather events have amplified the importance of addressing exposure of gas-fired generation to pipeline delivery constraints. As PJM continues to rely on natural gas generation, pipeline contingency analysis will continue to play an important role in planning for resilience.

10 | **Renewable Resource Availability** – Planning will use the Effective Load Carrying Capability (ELCC) methodology to account for the typical variability of weather-dependent wind and solar resources and continue to explore enhancements to increase confidence in study findings.

11 | **Loss of Transmission** – Planning and Operations must consider extreme events, such as hurricanes, derechos and geomagnetic disturbances in planning studies and assess potential measures to mitigate impacts and respond to such events, as outlined in **Section 6.6.**

## 7.4 RTEP Process Enhancements

PJM's RTEP process continues to evolve as the scope of system enhancement drivers continues to shift. These efforts, including the ones enumerated below, will continue to bring the grid of the future into clearer focus:

| | | | |
|---|---|---|---|
| **1.** Interconnection Process Reform | **2.** Generator Deliverability Methodology | **3.** Effective Load Carrying Capability | **4.** Probabilistic Planning Techniques |

These are summarized below.

### 7.4.1 Interconnection Process Reform

PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of generator fuel type. The process has been key to helping states achieve renewable targets. PJM recognizes, though, that changes are warranted, driven by sustained, record-setting levels of interconnection requests received each year, directly impacting PJM's study process volume and timing. In 2021, for example, PJM received 1,351 new service requests, more than triple the 470 new service requests received just three years prior and the highest number since implementation of the interconnection queue 25 years ago in 1997.

PJM's interconnection process is a critical step in integrating renewable generation into the grid as part of federal and state policy goals. To that end, PJM and stakeholders continue to improve process efficiency and reduce study backlogs.

### 7.4.2 Generator Deliverability Process

In 2021, PJM initiated discussions with stakeholders to improve variable resource modeling. PJM is pursuing modifications to the RTEP process generator deliverability methodology to more accurately reflect emerging resource mix under light load and winter operating conditions. The existing generator deliverability procedure is overly complex and has remained relatively unchanged for many years. PJM's discussions with the Planning Committee will continue in 2022.

### 7.4.3 Effective Load Carrying Capability

PJM continues to witness extraordinary growth in energy storage and intermittent generating resources, such as wind, solar and other renewables. As a result, the manner in which PJM evaluates the contribution of such resources toward resource capacity value has also evolved. Prior to 2021, PJM calculated the resource capacity value of an intermittent resource, and that which historically has been labeled as "limited duration," by a methodology independent of changes to the overall resource mix. This meant that a resource's capacity capability and its contribution toward meeting PJM's resource adequacy requirements would not have been impacted by the amount of renewables and energy storage within the RTO as a whole.

This began to draw PJM attention and concern in 2018, given that increasing amounts of intermittent and limited-duration resources impact hourly loss-of-load probability (LOLP) risk profile. Without recognizing this dynamic, PJM could otherwise be overvaluing or undervaluing intermittent and limited-duration resource contribution to resource adequacy over time. The PJM Capacity Capability Senior Task Force (CCSTF) – created by the Markets and Reliability Committee in March 2020 – developed an ELCC methodology suitable to PJM to determine the capacity capability of renewables and storage. The results of the studies that were the outcome of that effort became effective in the second half of 2021. PJM's 2021 Region Transmission Expansion Plan report Section 2.3.2 discusses this in more detail. In addition, the PJM Planning Committee also initiated a separate stakeholder process in 2021 to review and modify existing CIR request and retention policies, with an emphasis on ELCC resources, including the application of CIRs to the ELCC methodology and UCAP valuation.

### 7.4.4 Probabilistic Transmission Planning

Since the implementation of the RTEP process in 1999, PJM has continued to add reliability planning criteria. These now include winter peak conditions, low-load system conditions, and natural gas pipeline contingencies in addition to summer peak load planning conditions. While existing transmission planning relies on a set of models, assumptions and scenarios using deterministic analytical tools, more powerful techniques can be used for longer-range scenario development to better understand the full range of grid of the future system conditions. This is particularly true given the added complexity associated with renewable generation variable output profiles.

#### 7.4.4.1 Evaluating Resilience

As indicated in **Section 1,** PJM currently incorporates probabilistic methods into its planning process to analyze high-impact, low-frequency events and to identify areas of risk and potential resilience enhancements to the grid. Since the attacks of 9/11, the power industry has taken a closer look at system contingencies not only driven by naturally occurring events but additional man-made threats as well, including: (1) cyberattacks, (2) loss of interdependent systems, (3) earthquakes, (4) physical attacks, (5) severe terrestrial weather, (6) geomagnetic disturbances, and (7) electromagnetic pulses.

PJM uses cascading tree analysis to assess the probability and consequence of cascading outages in electric systems. PJM is currently developing a metric of resilience to complement and enhance a planning process that traditionally has been focused on reliability and market efficiency. The cascading trees methodology could be used in decision-making and as a driver for new projects. For example, transmission corridors that appear frequently across multiple cascading paths are good candidates for system reinforcements significantly lowering the probability of a severe cascading outage.

#### 7.4.4.2 Grid of the Future Scenario Analysis

A larger shift to stochastic models could become an effective transmission planning tool. One application could involve renewable generation output profiles. These techniques may require a shift away from a deterministic elimination of violations to the identification of an optimal hedge against probable scenarios. These models, however, raise a number of complex issues that will require further thought and resolution:

**1 |** How to assign a proper probability to a scenario

**2 |** Resolving disagreement over assigned probabilities

**3 |** What constitutes an optimal hedge in all scenarios (e.g., eliminate or minimize violations for 99% of cases)

**4 |** Compatibility with other analytical tools (e.g., AC power flow, transient stability, electromagnetic transient, etc.)

PJM believes that probabilistic methods can be a valuable planning tool and will continue to study the application and effectiveness of probabilistic approaches.

## *7.5 Regulatory Action*

PJM engagement with federal and state policymakers is critical to successful grid planning initiatives focused on renewable integration coupled with impacts of current trends in generation, transmission and load. Indeed, grid of the future trends associated with decarbonization are significantly driven by public policy, including FERC's July 15, 2021, Advance Notice of Proposed Rulemaking (ANOPR), entitled, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection. Discussion of PJM's Initial Comments and Reply Comments can be found in PJM's 2021 Regional Transmission Expansion Plan report, Section 1.4.10.

### 7.5.1 Reliability Criteria for Extreme Events

As stated in its ANOPR response, PJM's ongoing efforts are taking a forward-looking, holistic and proactive approach to plan grid of the future transmission needs with respect to extreme events, which may become a more significant grid expansion driver under higher levels of renewable penetration. The scope of planning studies will support efforts to assess how extreme events can be analytically evaluated and how consequential impacts to system reliability are identified. This may lead to new reliability criteria and planning tests. To that end, Planning will continue to work with stakeholders to consider planning process policy changes that may be needed to enable PJM to identify and plan needed transmission to address extreme events.

### 7.5.2 Interconnection Pricing Policies and Cost Allocation

Recognizing ongoing grid evolution, and in parallel with the Interconnection Process Reform Task Force discussed above, PJM undertook a series of Interconnection Policy Workshops beginning in May 2021 to encourage stakeholder discussions regarding cost-allocation methodologies and whether any changes or enhancements to the current participant funding approach are warranted.

Through the workshops, PJM and its stakeholders have discussed six potential alternative interconnection cost responsibility options.[51] Implementing one of the six could replace the present "cost causer pays" rule out of FERC Order 2003 and provide a more efficient and fairer way to allocate interconnection-related costs. Each option offers an approach that can address more than a single queue project, in anticipation of greater penetration of renewables and attendant volume of grid interconnection requests.

### 7.5.3 State Electrification Policies

As discussed above, state policies on electrification can be an important factor in the behavior of end users when opting to convert to electric transportation – including the charging behavior of EVs – and building heating. PJM continues to monitor these policies as they evolve, provide education where appropriate and update planning studies to reflect current polices.

### 7.5.4 Potential DER Reliability Issues

Growing levels of DER can, if not addressed adequately, create reliability challenges. FERC must ensure that DER is held to reliability, performance and cybersecurity standards that ensure grid reliability. State policies also impact customer DER facility performance characteristics. Importantly, PJM must continue to encourage state policies that also ensure reliability, enable PJM to cost-effectively plan grid expansion and facilitate data sharing.

### 7.5.5 Continued Development of Grid-Forming Inverter Technology

The challenges created by a rapidly shifting generation fleet must be addressed by NERC in its standard-setting initiatives and enforcement activities, as well as by policymakers at state and federal levels. Defining essential reliability services is necessary in the face of the increasing frequency of extreme weather events and growing levels of IBR-based, variable renewables.

## 8. Summary

As discussed in this report, many drivers are influencing PJM's generation mix, including state and federal policies as well as economic factors. The overall impact is that during the next 15 years, PJM anticipates that it will integrate more than 100,000 MW of onshore wind, offshore wind, solar and storage resources in addition to the 15,000 MW already in service. In order to interconnect these resources, future grid enhancements alone are estimated to be on the order of more than $3 billion, based on the first phase of PJM's OSW Transmission Study for OPSI. In order to plan for this shift in the generation portfolio mix, the study was a first step in considering the transmission needs to move toward a decarbonized grid.

This report marks a major step forward in the multi-year effort to implement PJM's grid of the future corporate strategy, as reviewed and approved by the PJM Board. A collaborative internal team made up of subject matter experts from throughout PJM continues to implement the road map discussed above in **Section 7**. Planning has also

[51] Interconnection Policy Workshop: Session 3 Presentation of Six Options at https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20210722-workshop-3/20210722-item-03-interconnection-policyreforms-overview-presentation.ashx.

researched and reviewed external future grid initiatives by other ISOs/RTOs, states themselves, and industry studies and white papers. That collective research has informed the degree to which key drivers – generation shift to renewables, electrification-driven load impacts, emerging technologies and extreme event resilience – are governing the development of the grid of the future road map described in this report.

Over the past decade, increasing focus by federal and state governments on climate change, energy independence and other policy areas continues to make clear the critical role of the transmission system. And, while the existence of violations of NERC Reliability Standards is the basis for PJM's determination of need, construction of new transmission infrastructure will enable federal and state governments to promote public policy goals. An important element of these policies is greater use of renewable resources, primarily wind and solar, the integration of which presents a unique set of challenges to planning. PJM's future grid will encompass the operational flexibility to address key drivers that will be significantly different with increased penetration of variable, renewable resources.

The grid of the future is not some far-distant idea but is here now. PJM, like other RTOs across the U.S., has before it a robust, reliable transmission grid, but one upon which enhanced operational flexibility must continue to grow to ensure uninterrupted power delivery 24/7 year-round.

9 May, 2022

# Rail service 'meltdown' constraining US coal sector in hot market

Author Taylor Kuykendall
Theme Energy, Metals

**U.S. coal demand is on the rise and has lifted prices, but coal producers are struggling to get the rail service needed to further increase shipments.**
*Source: Alan J. Nash*

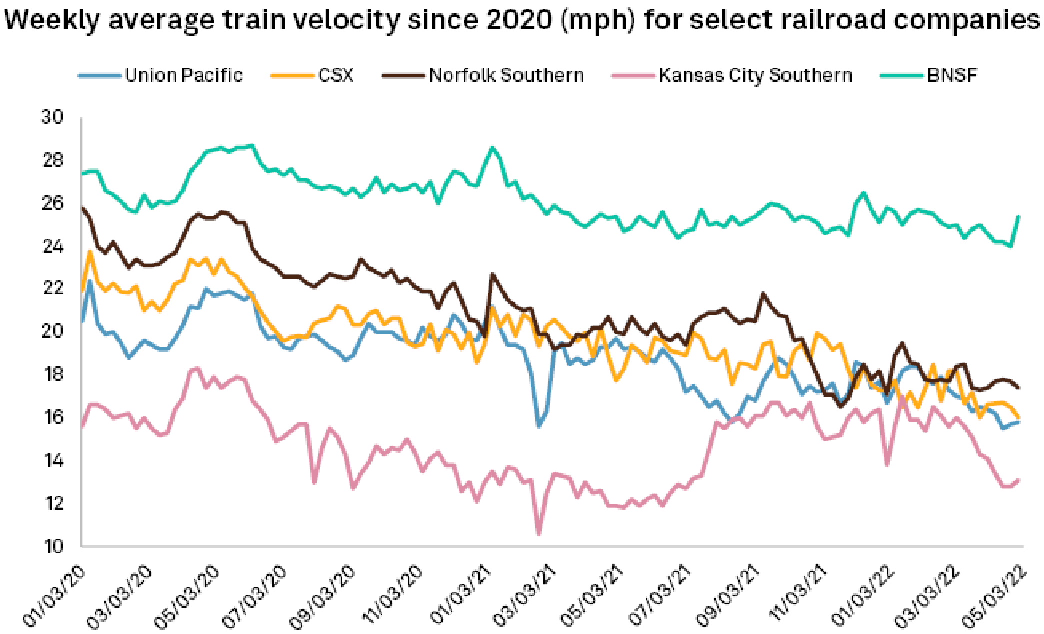
U.S. coal miners, eager to sell into a reinvigorated market, are struggling to move their product as train lines tangle with a severe labor shortage.

International prices for the thermal coal used by power plants and the metallurgical coal used to make steel have climbed dramatically over the last 12 months as domestic demand and international demand bounced off pandemic-driven lows and coal producers amped up production volumes. But coal is piling up at the mine as expected freight trains simply do not show up.

Overall, rail employment is down 20.4% since January 2019, according to the U.S. Bureau of Labor Statistics. Train operators are working to address the issue but acknowledge it could take several months to fix the shortfall in workers. The assessment of high-vol A metallurgical coal prices from the U.S. East Coast, for example, climbed as high as $525/tonne in March after spending most of 2020 just above $100/tonne, but the supply response has been limited due to the slower train service and other factors.

Coal companies are frustrated over the inability to move more coal into the soaring market.

"The situation is entirely attributable to a meltdown in rail service capability that is affecting shippers of every size and type," said John Ward, executive director for the National Coal Transportation Association, a trade association funded by coal producers and power utilities.




Data compiled May 3, 2022.
• Train velocity values can be adjusted due to settling, periodic enhancements and methodological updates.
• CSX defines train velocity as the speed of a train from origination to destination, including the amount of time a train dwells in a yard for a crew change, pickup or set-off of traffic, also known as "intermediate dwell".
• Union Pacific defines train velocity as measure of time from origin departure until final arrival, including time at intermediate terminals and calculated by dividing train miles by train hours for through freight trains.
• Norfolk Southern train speed measures the line-haul movement between terminals. The average speed is calculated by dividing train-miles by total hours operated, excluding yard and local trains, passenger trains, maintenance of way trains, and terminal time. System-wide average train speeds are given for several train types.
• Kansas City Southern Lines defines train velocity as a train level metric measuring the average velocity of a train between its origin and destination stations, calculated as the sum of the miles traveled divided by the sum of total transit hours. Transit hours are measured by calculating the difference between a train's origin departure and destination arrival date and times broken down by segment across the train route. This metric includes all time spent at intermediate locations between a train origin and destination (including all crew changes, terminal dwell, delays, and incidents). The weekly metric is calculated by taking the sum of all train miles divided by the sum of all transit hours for all trains in each respective category in a given week.
• BNSF measures train velocity according to the Surface Transportation Board's Rail Service Metrics rulemaking, where the train speed should be measured for line-haul movemnets between terminals. The average speed for each train type should be calculated by dividing total train miles by total hours operated.
Axis for mph begins at 10.
Sources: CSX Corp.; Union Pacific Corp.; Norfolk Southern Corp.; Kansas City Southern Lines; United States Department of Agriculture.

## Train service impeding coal sales

Many coal producers celebrated improved and even record financial results in recent quarterly reports, but also found that inadequate rail service was preventing a more robust rebound in sales. Coal production increased 8.0% year over year in 2021, according to S&P Global Market Intelligence data.

"Rail performance has been extremely disappointing as we worked through the quarter," Arch Resources Inc. Senior Vice President and COO John Drexler said on an April 26 earnings call. "It's been our biggest challenge and it's created a host of issues for us to be working through and dealing with."

Arch estimated that it received only 60% of the trains required by its Eastern U.S.-based metallurgical coal segment during the first quarter of 2022. While the company said rail services met nearly 70% of those requirements by March, less than half the trains required to match supply levels were arriving in January, the company said.

The coal producer estimates it is now receiving about 80% of the trains typically expected.

"That means we're still adding coking coal to already swollen stockpiles," Drexler said.

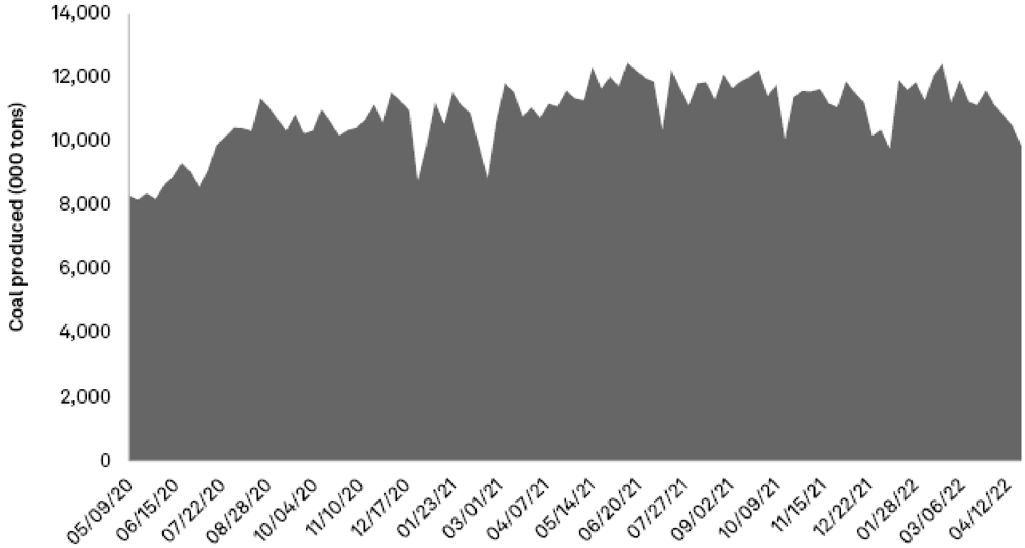
Rail issues are also impacting on shipments from the Western U.S., where companies primarily mine thermal coal used for power generation. Arch executives noted that, while the company has sold above its guidance range for Western U.S. coal this year, they expect about 5% to 10% of output to be pushed to later years due to rail issues.

During an April conference hosted by the National Coal Transportation Association, 92% of members participating in a survey said that rail service shortfalls had impacted their company's transportation of coal, with 64% reporting resulting modifications to operating plans in the second half of 2021.

Executives with Peabody Energy Corp., the nation's largest coal producer, have also flagged the impact of railroad service on its coal deliveries, while Warrior Met Coal Inc. estimated on a May 5 call that poor rail performance cost its business $32 million in net income in the first quarter. Other coal companies that have noted issues with rail service during first-quarter earnings calls include Consol Energy Inc., Alliance Resource Partners LP and Alpha Metallurgical Resources Inc.

A survey of utility members also conducted by the National Coal Transportation Association in April found that two-thirds reported poor rail service, and over half reported it was getting worse. Of its utility members, 78% reported missed coal shipments due to rail issues while even more said railroad service is negatively affecting the ability to maintain power plant coal stockpiles.

US weekly coal production




Data compiled May 3, 2022.
Production figures between May 9, 2020, and April 23, 2022.
Source: S&P Global Market Intelligence

## Good help, hard to find

The U.S. Bureau of Labor Statistics estimated there were 183,000 employees in the rail transportation sector as of January 2019. That figure dropped 20.7% to 145,100 by January 2021 and has since gained little to no ground.

BNSF Railway Co., which ships more coal by volume than any other rail service in the U.S., plans to hire approximately 1,000 additional train crew personnel in 2022 and already has 300 people in crew training, BNSF spokesperson Ben Wilemon wrote in an email. The company has also seen a "significant improvement in crew availability" since updating its attendance policy in February, the spokesperson said.

"BNSF teams have implemented an aggressive service recovery program to generate velocity and fluidity improvement across the network," Wilemon said. "We are making incremental progress in addressing elevated railcar inventory levels, reduced velocity and resource imbalances with freight volumes."

Norfolk Southern Corp. said it has ramped up hiring with 850 active conductor trainees and more on the way. The rail service has also rolled out a plan including capital expenditures to expand its network capacity.

"We are laser-focused on improving service; however, we continue to operate in a tight labor market, and demand on the national supply chain remains extraordinarily high," a Norfolk Southern spokesperson told Commodity Insights.

A Union Pacific Corp. representative told Commodity Insights that the rail service provider is working with customers to address the impacts of several "disruptive events." That includes training new employees, relocating crew members to high-demand areas and adding new locomotives to its fleet.

CSX Corp. is also addressing delays related to the explosion of a coal transfer tower at its Curtis Bay coal terminal in late 2021. A CSX representative said the company expects that facility to be fully repaired later this year and noted the company is also bringing on more employees.

**Coal producers demand action**

Rail service providers did not say when they would be able to restore service to acceptable levels while attending a two-day hearing on freight rail service issues held by the Surface Transportation Board starting April 26, Ward said.

Industry observers estimate rail service could return to acceptable levels as soon as the third quarter of 2022 or as late as mid-2023, Ward added.

The National Coal Transportation Association and other parties have called on the Surface Transportation Board to take action to improve rail service. That includes potentially requiring increased transparency about reducing or rationing service, requiring action plans to remedy railroad delay issues and imposing certain financial limitations on rail service providers.

Some coal companies are even hiring and training additional staff to load trains when — or perhaps if — they arrive. Katie Mills, counsel for the National Mining Association wrote in a testimony to the board that one coal company was considering third-party rail services for loading, while another was considering reopening a river terminal to move coal.

"Just because the mines are running full speed ahead, it does not necessarily mean that coal is moving across the country by rail," Mills wrote. "The issue is not the number of cars on trains, it is that the trains often do not show up at all."

*S&P Global Commodity Insights produces content for distribution on S&P Capital IQ Pro*.

# Railroad strike threatens power in coal-dependent states

Coal's dependence on railways could lead to electricity shortages and sky-high prices.

*Kathryn Scott Osler / The Denver Post via Getty Images*

Jake Bittle

**Published** Sep 14, 2022

**Topic** Climate + Energy

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Tens of thousands of U.S. railroad workers in several different unions are poised to strike at the end of this week after a prolonged labor dispute. The workers have been unable to reach an agreement with a group of six rail carriers despite months of back-and-forth on issues like stagnant pay, long shift lengths, and an inability to take time off.

Biden administration officials have been racing to mediate between the parties ahead of a Friday deadline, hoping to avoid a railroad strike and shutdown that the Department of Transportation has estimated would cost the economy about $2 billion a day. Biden himself convened a Presidential Emergency Board two months ago to help supervise the talks, but the board has been unable to help the two sides come to a final resolution. Marty Walsh, the administration's labor secretary, postponed a planned visit to Ireland this week to help with the negotiations.

The looming railroad workers' strike threatens to deliver a blow to the economy by disrupting critical supply chains for commodities like lumber and wheat. No sector stands to lose as much as the coal industry, which is almost entirely dependent on railways to move its product around. A work stoppage could reduce coal stockpiles that have already been thinned by poor rail service and global energy markets. This could lead to electricity shortages and sky-high prices in coal-dependent parts of the country.

Coal is by far the most rail-dependent fossil fuel. The lion's share of crude oil and natural gas moves around the country on pipelines, but you can't put coal in a pipeline, so it has to move on trains, trucks, and barges. Because the fuel is so heavy and takes up so much space, rail is the only economical way to transport it from mines to power plants: The average coal train consists of 140 cars that each hold about as much coal as could fit on ten trucks. Even if coal could be shifted onto trucks, the trucking industry itself has also been experiencing labor shortages, and there's not much excess truck capacity to absorb rail freight.



"We are captive shippers," said John Ward, the executive director of the National Coal Transportation Association, a trade group



alternatives.

The industry's reliance on rail has proven to be a constraint even before the recent union disputes. A railroad industry labor shortage has already led to thinner and less reliable rail service, hampering coal producers' ability to move their products around and reducing coal stockpiles at power plants around the country. A survey from the National Coal Transportation Association earlier this year found that around 80 percent of utilities said they'd missed coal shipments thanks to faulty rail service. A prolonged rail shutdown would supercharge that dynamic, forcing coal miners to hold on to more of their product.

"Coal stockpiles are already at historic lows in the United States," said Ward. "Any further interruptions could be disastrous for power generation. In the good old days, it wasn't uncommon for utilities to have a 60- or 90-day supply of fuel, but I don't know anybody who has that luxury now. If it became an extended strike, the consequences could be dire." Should utilities burn through their stockpiles, they'll have to slow down generation to save supply, which could lead to power shortages during times of peak demand. Prices would jump for as long as the supply backlog lasted.

The worst-affected places would be states like West Virginia and Missouri, which generate around 90 percent of their electricity from coal and don't have the opportunity to switch to natural gas on short notice. Even states with large gas supplies will struggle, though, since gas markets are also tight as producers export large quantities of gas to Europe.

The U.S. coal industry has been on the wane for decades thanks to and a newfound abundance of cheap natural gas. Domestic coal consumption has fallen by about half since 2005, contributing to an almost 30 percent decline in power-sector greenhouse gas emissions over the same period.

But the post-pandemic-lockdown rebound in energy consumption and the Russian invasion of Ukraine have shocked the industry back to life, causing prices to skyrocket amid an overall energy shortage. Still, analysts don't expect the jolt to lead to much new production, since the long-term economics of the coal industry are still so bad. An industry trade group expects around 86 gigawatts of coal generation to retire over the next decade — close to half of the current capacity.



**Next Article**

A headshot of Ian Solomon.

# ‘I just want my people out here’: Black-led groups in Detroit are cultivating access to nature

Rukiya Colvin, Planet Detroit · Equity

**Energy**

Gas stove painted on grass

A gas utility's astroturf campaign threatens Oregon's first electrification ordinance

**Joseph Winters**

The hazards of gas stoves were flagged by the industry — and hidden — 50 years ago

**Kate Yoder**

Construction begins on controversial lithium mine in Nevada

**Gabriela Aoun Angueira**

Newly revealed records show how the EPA sided with polluters in a small Montana mining town

**Wilson Criscione, InvestigateWest**

**Latest**

A photo of the Washington State Capitol in Olympia.

How Washington raised $300 million for climate action from polluters

**Kate Yoder**

An unexpected source of methane? Your local sewage plant.

**Siri Chilukuri**

How disaster relief leaves Kentucky's landslide victims behind

**Austyn Gaffney & Martha Park**

Biden administration pledges $25 million to bring bison back to tribal lands

**Joseph Winters**

Sustainability

As part of our commitment to sustainability, in 2021 Grist moved its office headquarters to the Bullitt Center in Seattle's vibrant Capitol Hill neighborhood. Known as one of the greenest commercial buildings in the world, since it opened its doors on Earth Day in 2013 the Bullitt Center has been setting a new standard for sustainable design.

NATIONAL WEATHER SERVICE
NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION

# Low River Stages along the Lower Ohio and Mississippi Rivers

**Paducah, KY**
Weather Forecast Office



## Overview

Driven by months of drought and periods of extreme heat during the summer and fall months in 2022, very low to record low river stages developed along the Lower Ohio and Mississippi Rivers in our area. In October 2022, river stages on the Mississippi River from the Ohio-Mississippi River confluence at Cairo, IL, to Baton Rouge, LA, were so low that commercial activities such as barge traffic and riverboats were experiencing difficulty navigating portions of the river.

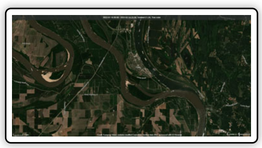
True color satellite imagery showing the change between July 14 and October 17, 2022, of the Lower Ohio and Mississippi Rivers from their confluence at Cairo, Ill., to the Kentucky Bend of the Mississippi River at New Madrid, Mo.
Source: Copernicus Sentinel 2.

**Satellite Imagery** | Photos | Drought | Historically Low River Stages

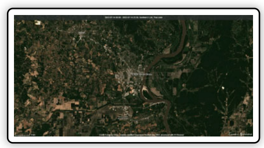
### Satellite Imagery

**These true color satellite images from Copernicus Sentinel 2 show the difference in river levels along the Lower Ohio and Mississippi Rivers between July 14 and October 17, 2022. Click each image to enlarge.**

Ohio River at Mound City Landing in Illinois and Kentucky.



Confluence of the Ohio and Mississippi Rivers at Cairo, Ill.



Mississippi River at Cape Girardeau, Mo.

Mississippi River at the Kentucky Bend and New Madrid, Mo.

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NEWS

# CenterPoint Energy request 3-month rate hike for 2023 following coal plant failure

Karl Schneider
Indianapolis Star

Published 5:03 a.m. ET Nov. 25, 2022 | **Updated 9:54 a.m. ET Nov. 25, 2022**

CenterPoint customers in seven southern Indiana counties could see a three-month rate hike next year as the utility company seeks approval for a fuel cost adjustment.

CenterPoint Energy Indiana South filed a petition with the Indiana Utility Regulatory Commission on Nov. 16 that, if approved, would allow an approximate $13.20 monthly increase in electricity bills for February, March and April for its roughly 150,000 customers in southern Indiana.

The amount is based off the average energy used for an Indiana household, which is 1,000 kWh per month. The utility provides electricity in seven counties: Pike, Gibson, Dubois, Posey, Vanderburgh, Warrick, and Spencer counties.

The rate increase request comes after the utility had to purchase power from the Midcontinent Independent System Operator (MISO) network due, mainly, to a coal-fired plant becoming inoperable after a turbine failed, according to partially redacted testimony of CenterPoint Vice President of Power Generation Operations Wayne Games.

The turbine failed June 24, leaving CenterPoint's Culley Unit 3 inoperable for the rest of 2022. Games also testified that volatile fuel costs for the coal-fired plant were also part of the reason CenterPoint filed the petition.

Kerwin Olson, executive director of consumer advocate group Citizens Action Coalition, said utility customers should not be expected to pick up the tab for replacement power when a plant goes offline.

“That always irks consumer advocates because rate payers continue to pay for the power plant,” Olson said. “So, they’re paying for a power plant that’s not producing energy and at the same time they’re forced to pay for replacement power because the power plant is not working.”

The most disappointing and frustrating aspect of the petition, Olson said, was that most of the information is confidential.

“It’s completely unacceptable,” Olson said.

**More:** Utility companies, Indiana offer billing assistance for winter home heating

Games testified that CenterPoint, working with General Electric, has found a replacement turbine in a decommissioned coal-fired plant in Montana. GE will purchase the turbine from the plant, disassemble and refurbish it before transporting and installing it at CenterPoint.

The projected in-service date for the replacement turbine in Culley Unit 3 has been redacted due to the CEI South filing, which requested that some information in the testimony be classified as confidential. Games said that GE estimated 6-12 months from the time the replacement was located and purchased. The cost of the work to return the Culley Unit 3 to service was also redacted.

Commissioners asked Games during testimony to explain the benefit of this approach to CEI South customers. Games’ entire answer is redacted.

CenterPoint’s motion for these redactions says Games’ testimony contains “competitively sensitive trade secrets and protected critical infrastructure information.”

The commission’s decision on CenterPoint’s petition is pending, but Olson said he expects one by January.

Recently a NIPSCO cost-recovery petition was denied a similar request after a fire at its Schahfer Unit.

“There have been occasions where the commission has denied cost recovery,” Olson said. “Sometimes it has been necessary for consumer advocates to get involved and make those requests. It’s hard to say what the commission would do absent of stakeholder involvement.”

*Karl Schneider is an IndyStar environment reporter. You can reach him at karl.schneider@indystar.com. Follow him on Twitter @karlstartswithk*

*IndyStar's environmental reporting project is made possible through the generous support of the nonprofit Nina Mason Pulliam Charitable Trust.*

FORBES > BUSINESS > ENERGY

# Inflation Reduction Act Benefits: Billions In Just Transition Funding For Coal Communities

**Energy Innovation: Policy and Technology** Contributor ⓘ
*We are a nonpartisan climate policy think tank helping policymakers make informed energy policy choices and accelerate clean energy by supporting the policies that...*

**Michelle Solomon** Contributor ⓘ
*I am a Policy Analyst at Energy Innovation, focus: clean electricity*

0 Aug 24, 2022, 07:30am EDT

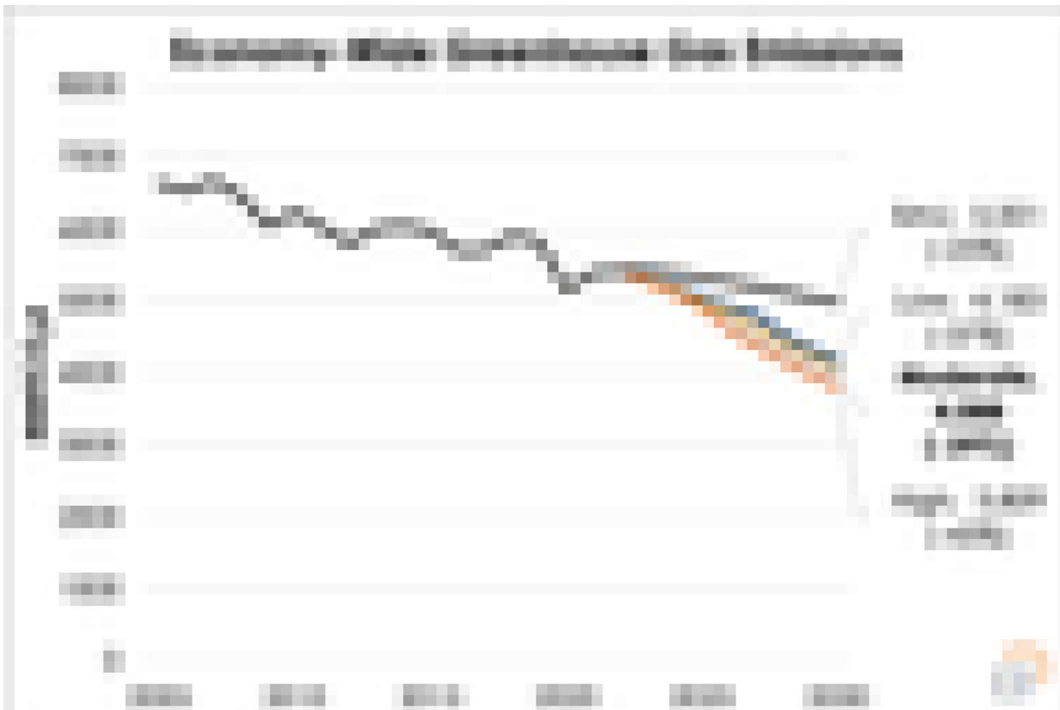
Listen to article 11 minutes

*Michelle Solomon is a co-author of this article.*

The Inflation Reduction Act (IRA) is the most significant climate legislation in United States history. Energy Innovation Policy and Technology LLC® modeling finds the IRA's $370 billion in climate and clean energy investments could cut U.S. greenhouse gas (GHG) emissions up to 43% below 2005 levels by 2030.

Combined with state action and forthcoming federal regulations, the IRA puts the United States within reach of its Paris Agreement commitment to cut emissions 50% to 52% by 2030. The IRA will strengthen the U.S. economy by creating up to 1.3 million new jobs and avoid nearly 4,500 premature deaths annually by reducing air pollution, both in 2030.

In this series, Energy Innovation® analysts showcase the IRA's benefits in the power, buildings, and transportation sectors of the U.S. economy. This article is one of two covering the power sector, detailing the IRA's provisions to transition the U.S. power sector from coal to clean.

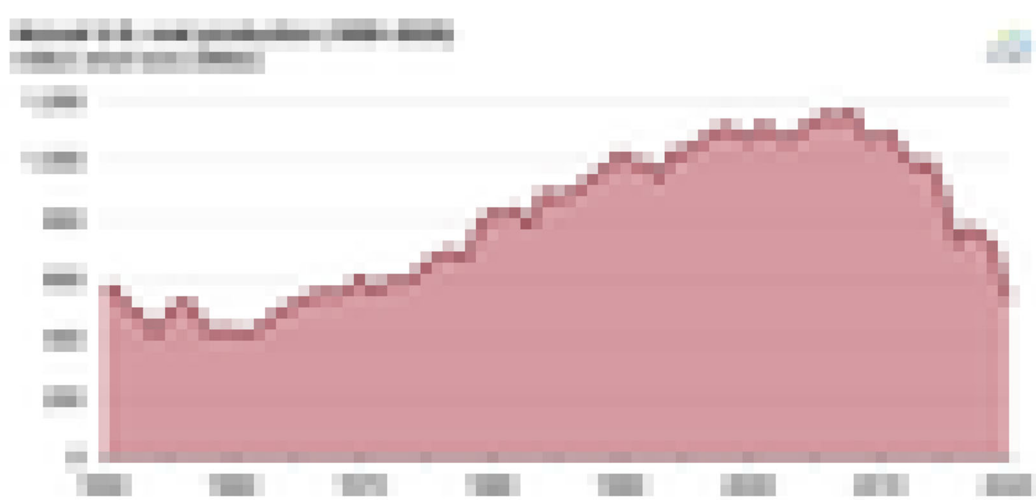


Emissions reductions under provisions in the Inflation Reduction Act. ENERGY INNOVATION

The IRA provides a full suite of tools to move us toward clean electricity, including critical clean energy technology tax credits. By coupling these tax credits with financial support to pay down uneconomic fossil plants, the IRA opens the door to new cheap and clean generation resources. And it does it all with an eye toward the energy-dependent and rural communities that need it most.

## Coal is declining – but a just and speedy transition is not guaranteed

The U.S. coal industry is in irreversible decline, with 2022 coal consumption expected to be lower than 2021 despite sky high gas prices for much of the year, as economics and clean air standards persistently drive coal's decline. Economic competition from gas took coal's market share first, and now renewables will most likely outcompete coal going forward. Eighty percent of existing U.S. coal plants either cost more to continue operating compared to replacement by local wind or solar, or are slated to retire by 2025. Impending Environmental Protection Agency pollution standards for both new and existing plants will likely worsen coal's financial outlook.



U.S. Energy Information Administration, Annual Coal Report ENERGY INFORMATION ADMINISTRATION



Though the clean energy transition is happening, coal retirements must be accelerated to reach our climate goals. The IRA will speed the shift from coal to clean and support a just transition by providing $5 billion to back $250 billion in low-cost loans for utilities to reduce coal debt and reinvest in clean technologies. Another provision provides $9.7 billion in financial assistance for rural electric cooperatives to move toward clean energy sources.

Between this financial assistance, expanded clean energy tax credits, and more, Energy Innovation finds the IRA's power sector provisions will drive about two thirds of its GHG emissions reductions, expanding 2030 wind and solar capacity by 2 to 2.5 times pre-IRA projections. By accelerating coal retirements and clean energy deployment, the IRA could also reduce retail electricity costs up to 6.7%, saving consumers up to $278 billion over the next decade.

## Undepreciated assets create a huge barrier to coal plant retirement

As of 2021, 93% of coal capacity was still owned and operated under long-term contracts or "cost of service" regulation. This financial incentive for utilities keeps coal plants running, despite the expense to their customer's wallets and lungs.

Under cost of service regulation, monopoly utilities can recover capital investment costs, plus a healthy return, via the rates they charge to their captive customers. Typically, the utilities recover those costs over the entire lifetime of a coal plant and will continue charging their customers and receiving investment returns until the plant is fully depreciated and retires.

Early plant retirement creates financial uncertainty, as regulators and consumer advocates can argue that cost recovery is no longer justified. On the other hand, if utilities are allowed to continue earning their expected profits, customers may pay for idle coal plants for years to come—needlessly increasing the cost of a coal-to-clean transition.

Refinancing may be the most equitable and palatable option regulators have to deal with retiring uneconomic coal plants, as it can reduce interest rates on the remaining value and pass fewer costs onto customers without major utility balance sheet disruptions.

The stacks from the Gavin coal burning power plant dwarf a small nearby home in Cheshire, Ohio. ... [+] GETTY IMAGES

Refinancing or "securitizing" stranded asset costs has been used since power sector deregulation in the 1990s when monopoly utilities were forced to divest from power plant assets, often at a loss, which left customers on the hook. Securitization leverages consistent cashflow from captive customer electricity bills to achieve AAA bond ratings. These bond ratings, on par with U.S. government bonds, unlock much lower refinancing interest rates.

This concept has been recently applied to accelerate coal plant retirement and save consumers money. In New Mexico, the San

Juan Generating Station was closed via refinancing, and will save customers nearly $80 million in 2023 alone. However, because this type of transaction requires new legislation in many states, it cannot easily be scaled up to encourage a nationwide economic transition from coal to clean energy.

## How will the IRA speed coal retirements?

Two IRA provisions are designed to unlock low-cost financing for utilities across the country, vastly reducing the cost of retiring all existing coal generation by 2030, lowering electricity costs for customers, and enabling a just transition for fossil fuel communities.

The first provision creates a $5 billion fund for the U.S. Department of Energy's Loan Programs Office to facilitate low-cost loans up to $250 billion in principal. The government backing provides security needed for utilities to access financing at the lowest possible interest rates, the role previously played by ratepayer-backed securitization. This means customers will no longer have to pay high premiums for coal plants after they've been shut down, and utilities will not need legislation to enable this transaction in each state.

With over $176 billion still on the books from fossil plants around the country, this could make a serious dent in zeroing out coal-powered emissions.



The IRA unlocks refinancing for two types of projects—either replacing energy infrastructure or reducing emissions from energy infrastructure that will remain operational. Because the refinancing program is not simply for retiring old fossil plants but instead requires *reinvestment,* it creates maximum benefits for communities and utilities. These projects may also include remediation of the old fossil fuel sites during refinancing, ensuring timely clean up while providing additional local jobs.

To truly provide long-term economic development we will have to think even beyond energy industry alone, but this is a good start.

Solar energy and wind power stations GETTY

To access funds under the first type of project, utilities will need to “retool, repower, repurpose, or replace” retiring energy infrastructure rather than simply shutting the plants down. This will provide a lifeline to workers in those communities who would otherwise risk losing their livelihoods, and ensure a new source of tax revenue for public services.

But this reinvestment requirement is also good for business—as utilities refinance, they can build new infrastructure to maintain a healthy balance sheet.

The second use of the funding, to “avoid, reduce, utilize, or sequester” emissions from fossil plants, is also central to a just transition. Some plants will not be able to retire immediately due to specific roles they may play in maintaining reliability. However, refinancing these plants will free up capital for utilities to build new, clean resources even as they reduce generation from old fossil plants before they ultimately retire.

While the newly created Loan Programs Office authorization can be used across the energy industry, a second IRA program specifically targets rural electric cooperatives through the U.S. Department of Agriculture. Rural electric coops provide electricity to more than 40 million people, with disproportionately coal-heavy generation – coal provided 28% of their generation in 2020 compared to 19% nationwide. Because of their small size, many rural cooperatives can be financially vulnerable, and a single coal plant may make up a sizeable portion of their overall debt burden, making federal financial assistance particularly crucial.

Surrounding rural communities also bear a disproportionate burden of coal-related pollution, though shutdowns could mean the loss of jobs. To address these challenges, the bill provides $9.7 billion in flexible financial assistance for rural electric coops to reduce power plant emissions. Energy Innovation modeling finds that this funding could result in up to 20 GW of incremental coal retirements, providing rural communities support to reduce coal generation while ensuring new income sources.

These two provisions can clearly cut emissions by 2030, but questions remain about how much they will actually speed coal plant retirements given decision making is still left up to utilities.

One of the most crucial uncertainties surrounds how much of the funding will go toward zero-emissions technology, particularly with expanded tax credits for carbon capture and storage (CCS). To date, the majority of commercial CCS projects have been focused on enhanced oil recovery, while CCS remains unproven and risky in the power sector.

Despite the lack of viable CCS projects in the power sector to date, IRA modeling from the REPEAT project finds that power generation with CCS could increase significantly. To guarantee emissions reductions while providing maximum benefits to customers and energy communities, utilities leveraging these two programs should focus on replacing existing coal with new clean energy projects.

## With barriers torn down, it's time for clean electricity to shine

Without mandating fossil fuel reductions or clean electricity targets, the IRA is largely an incentive bill. However, it goes beyond simply making wind, solar, and storage cheaper than gas and coal. By pairing clean energy tax credits with these refinancing programs to pay off remaining plant balances, we finally have a more level playing field for clean resources to compete, while also bringing new economic opportunities to fossil-dependent communities.

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# Harnessing Financial Tools to Transform the Electric Sector

November, 2018

SIERRA CLUB

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# CONTENTS

## EXECUTIVE SUMMARY

In cost-of-service states, regulated utilities are continuing to operate generation units even though market signals show that the units should be replaced with more cost-effective alternatives. The reason for this behavior is that traditional regulatory mechanisms for dealing with the "stranded capital" of uneconomic generators suffer from significant drawbacks that render them unattractive to regulators, as each could cause harm to the utility, ratepayers, or both.

In this paper, we explore the merits of innovative financial tools that could help address these challenges and enable the transition to a more economically efficient electricity system. As we show, financial tools such as re-purposing excess collections in rates (such as the over-collection associated with tax reform), securitization, and green tariffs can provide funds to help smooth the elector-electric sector transition from fossil fuels to clean energy. We give particular attention to securitization with capital recycling as a key opportunity to advance the beneficial transition while minimizing harm to ratepayers and utilities, and providing a funding stream to impacted communities. Securitization allows ratepayers to directly raise low-cost debt to address near-term financing needs, while capital recycling helps the utility achieve reasonable profits for shareholders.

Each of these methods can be used to raise funds that help eliminate rate shock from accelerated depreciation and assist communities harmed by the closure of uneconomic generation plants. By relying on these tools, utilities, regulators, and other stakeholders can achieve the proverbial 'win-win' by which utilities are able to receive a reasonable return on their investments, expensive generation is retired, impacted communities have resources to smooth the transition, and customers benefit from lower costs.

# 1. INTRODUCTION

The United States electric sector is experiencing unprecedented change and opportunity. In 2017, unsubsidized wind passed economic parity with fossil-fired generation; it became the least-expensive option for new generation, and utility-scale solar is not far behind.[1] Combined with the depressed price of gas and a decade of investments in efficiency and demand response, operators of existing fossil and nuclear plants are realizing that they can no longer offer cost-competitive generation.

From 2008 to mid-2018, 65 gigawatts (GW) of coal-fired facilities retired in the U.S.[2] as owners determined alternative options were cheaper than continued operation. There is increasing evidence, both from national studies as well as recent utility actions, that clean energy options are increasingly competitive with both new[3] and existing[4] fossil generation, as well as increasing urgency to accelerate the pace of change.[5] The energy transition is the expected rapid shift from legacy fossil fuels to clean energy options that could occur over the next decade.

In March 2018, Bloomberg New Energy Finance (BNEF) issued a report titled with the conclusion that "Half of U.S. Coal Capacity on Shaky Economic Footing," because the long-run margins for those plants are negative;[6] i.e., they lose money by operating. In a competitive environment, owners of plants that are not currently profitable and have limited profitability prospects move to retire to avoid substantial ongoing losses. In fact, this thesis bears out in recent history: plants that relied on market-based revenues usually retired once profit projections sank below cost projections. For example, BNEF found that only 7% of the remaining merchant[7] fleet netted negative margins in the last six years. However, the BNEF report shows that a large majority of regulated[8] coal plants—both in organized market structures and vertically integrated states—have failed to retire even though their continued operation is uneconomic. BNEF notes that "regulated assets are stubborn; they are shielded by cost-of-service returns, and tend to linger longer after their economics sour."

Why do merchant and regulated owners act differently? By and large, merchant (or unregulated) owners of uneconomic power plants move to retire units that do not have a medium- or long-term prospect of a profit. With few exceptions, those merchant owners absorb any remaining or unpaid capital debt in the retired units, a loss which is passed onto investors. And while investors may not be pleased to absorb those capital losses, the alternative—absorbing both operating and capital losses through continued operation—is worse.

In contrast, regulated utilities are able to pass on costs to ratepayers, and unless a regulator specifically seeks to understand if an existing generator is competitive, those costs simply continue to be passed through. While regulators ideally demand that investor-owned utilities act as competitive enterprises, retirement decisions involve competing consequences that can cause a departure from market-optimal outcomes. Once a generating plant becomes uneconomic and a detriment to ratepayers, regulators usually face two unattractive options: either demand that investors absorb unrecovered capital costs, or pass those costs through to ratepayers who are no longer benefiting from the plant. The former is unattractive to the utility, which was authorized by regulators to invest in and operate the plant, and may not be able to absorb a loss without a credit rating impact. The latter is unattractive to ratepayers, who may either face rate increases to pay down debt, or are compelled to pay for power plants that are no longer in service. Because neither the utility nor the ratepayers, nor the regulators for that matter, are satisfied with the slate of unattractive options, they may reach an uneconomic, yet rational, impasse: choose to continue the operation of deeply uneconomic units simply to avoid an inevitable conversation about any unrecovered capital.

This is the impasse that we seek to overcome. The financial community has developed numerous tools to overcome analogous problems. Here, we explore three financial tools that would ease the transition away from uneconomic generation for investors, ratepayers, and regulators: 1) the diversion of over-collected earnings to depreciation, 2) securitization, and 3) green bonds and tariffs.

### THE ROLE OF FINANCE: CATALYZING ELECTRIC GENERATION TRANSITION

The retirement of uneconomic generation plants, and their replacement with lower cost clean energy resources is a net benefit. Financing tools offer the opportunity to make sure that those benefits are realized by ratepayers and redound to the owners, reducing the barriers to retirement and resistance to the clean-energy transition.

The financial tools we explore here raise capital to cover near-term costs by compensating investors from a stream of well-characterized future benefits. Specifically, we seek to address the key barriers to transition—stranded assets,[9] an erosion of utility earnings, rate shock for consumers, and equity for communities and—using three future benefit streams: tax incentives, future electricity cost savings, and economic opportunities for reinvestment of utility capital.

How big is the problem? In 2017, the Carbon Tracker Initiative (CTI), an independent financial think tank, estimated that regulated utilities are carrying $185 billion of potentially stranded assets in non-economic coal units.[10] As the cost of alternatives, and thus the fair market value of those coal plants, continues to fall that number will only rise. As the discrepancy between the low market valuation and high remaining balance increases, the risks to utilities rise—the risk that regulators will simply demand a plant be taken out of rate base. This is the outcome we seek to circumvent, providing a pathway for both ratepayers and utility owners while leading to cleaner outcomes and just transitions for impacted communities.

## 2. COST-OF-SERVICE REGULATION IMPACTS ON RETIREMENT DECISIONS

To understand the core challenge of transitioning the remaining regulated utility generation fleet to clean energy, we first need to understand the key features of cost-of-service regulation. We begin by reviewing these key features and then turn to a more detailed discussion of the resulting financial incentives and barriers to transition faced by utilities, customers, and communities.

### COST-OF-SERVICE REGULATION

Investor-owned utilities in many parts of the U.S. are subject to traditional cost-of-service regulation. Under the cost-of-service model, a utility makes capital investments in assets such as generation and transmission, and those investments are approved by a regulatory agency, a public utility commission. Ratepayers pay for the electricity service delivered by those assets much as they would for a mortgage: by paying back the utility's original investment plus a rate of return over time, and reimbursing the utility for other expenses as they are incurred (e.g., fuel and labor). This model of regulation predominates in states that do not have retail competition—i.e., in the Southeast, Midwest and Plains (except Texas, Illinois and Ohio), and West (except California).[11]

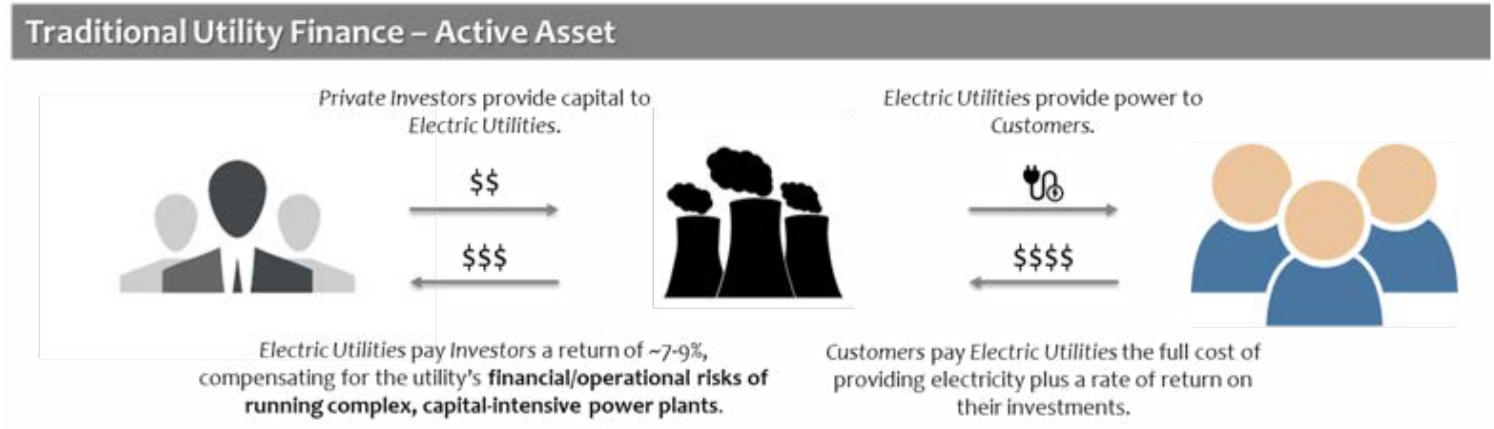
More formally, in cost-of-service regulation, the utility is authorized to charge customers rates sufficient to:

1. Recover the capital it invested in projects that are approved as used and useful for providing electricity service through steady depreciation charges (analogous to principal repayments made on a mortgage) spread over the project life;
2. Earn a rate of return (these are akin to interest payments on a mortgage) on the rate base—assets that continue to be "used and useful" but have not yet been fully paid for; and
3. Pay for the fuel and operations and maintenance (collectively termed "O&M") costs associated with running the system.

Collectively, these three elements constitute the revenue requirement—i.e., what the utility must recover from customers through rates. Utility monopolies are generally charged with providing reliable service at the least possible overall cost, and thus they should (at least in principle) prefer to minimize costs. The utility's expectation of full cost recovery—and a reasonable rate of return—for the assets it builds to serve customers is a core element of the "regulatory compact": the implicit agreement between the utility and the public utilities commission.

The rate of return is a set percentage applied to outstanding capital in the rate base—analogous to the interest charged on outstanding principal for a loan—and the primary way that the utility makes a profit. Because the utility "earns" this rate of return, it has a clear incentive to invest in capital assets. In contrast, utility owners are largely indifferent to O&M costs, which are passed through to customers without generating any profit.[12]

Capital investments made by utilities are typically recovered over a set period of time, called the "depreciable life" or "book life." At the outset, this period is typically set to coincide with an engineering-based estimate of how long the asset will be of use. Like a mortgage, the loan period is




typically decades. Unlike a home mortgage, the assumption is that as a plant's parts wear out, the plant becomes less useful. As a utility replaces worn-out parts of a large power plant, that asset life can be extended and the capital balance of the plant maintained. In the homeowner's analogy, the equivalent would be taking out additional loans to continue making home improvements. A conundrum arises when the theoretical engineering life of a power plant exceeds its expected economic life—i.e., when that plant has been priced out of the market—or in the home example, when that home's mortgage exceeds its sale value leaving the loan "stranded."

The graphic below shows the breakdown of the revenue requirements per megawatt -hour (MWh) of generation for a representative coal plant in 2016. The chart is divided into the three components: (a) the pass-through costs, including fuel and O&M expenses (Expenses), (b) capital depreciation and amortization (D&A), and (c) the capital rate of return (ROR). The ROR represents the earnings made by the utility owners on this asset.

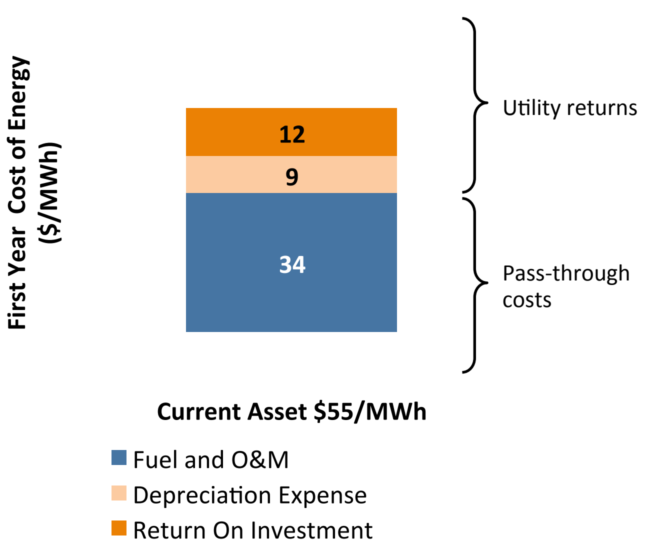



*FIGURE 1. FIRST YEAR REV REQ FOR EXAMPLE PLANT UNDER BAU*

In this case, our example plant's capital costs are based on a remaining plant balance (i.e., unpaid capital debt) in rate base of $433 million, with a remaining life of 20 years and an after-tax allowed rate of return of 7.35%. In this case, nearly two-thirds of every ratepayer dollar are just passed through to pay for fuel and operations. Only one-third of ratepayer revenues generate any returns—not a very attractive prospect from the utility's shareholders' perspective.

## THE REGULATORY CONUNDRUM OF EARLY RETIREMENT

The fundamentals of cost-of-service regulation continue to apply even when assets are retired early. The utility still expects to recover its capital outlay in full and to see a return on any capital that has not yet been recovered. Because the utility expected to recover capital over the full life of an asset, an early retirement leaves a reservoir of undepreciated capital. In the parlance of cost-of-service regulation, an asset approved for early retirement with an associated capital balance is deemed a "stranded asset."

Under cost-of-service regulation, regulators traditionally have three core mechanisms for handling stranded assets: disallowance, accelerated depreciation, or the creation of a "regulatory asset"—an asset that exists only on paper. Each has its disadvantages.

### Disallowance

In a disallowance, the regulator may determine that because a unit is retired and no longer provides service, it must be removed from rates. Under most circumstances, regulators are entitled to use this construct, but it is not without risk. While a disallowance can mean immediate rate relief for customers, it can have longer-term ramifications. A disallowance immediately reduces future cash flows and earnings without providing any funds for cost recovery that would allow the utility to pay off any outstanding debt. As a result, the company will have the same debt load but less cash to service that debt – potentially impacting its credit ratings and future behavior. A utility that receives a full or partial disallowance may be strongly inclined not to pursue additional retirements, even if they are cost effective. In addition, a lower credit score can impact the utility's cost of capital, making future projects more expensive. While there are certainly individual circumstances in which poor utility behavior may warrant disallowances, the prospect of a large disallowance incentivizes a utility to fight the retirement of an uneconomic asset, not support it.

**Accelerated Depreciation**

Under accelerated depreciation, a utility seeks to change its depreciation schedule to match the period until retirement, potentially shrinking the assumed remaining life from decades to years. From the utility perspective, accelerated depreciation ensures the rapid (and hence lower risk) recovery of capital. As a consequence, utilities can pay off their debt much faster—but ratepayers will see a much higher rate in those years as a result, even if the regulators decrease the utility's allowed return to reflect its lower risk. That is, ratepayers may be exposed to substantial rate shock under acceleration.

**Regulatory Asset**

Under the "regulatory asset" construct, the regulator authorizes a utility to retire a plant and remove it from service prior to achieving full cost recovery – but also authorizes the utility to continue collecting a return of and on investment after the plant itself no longer operates (hence a "regulatory asset", rather than a real asset). If the plant's pre-retirement depreciation schedule is used to set the amortization period of the regulatory asset, ratepayers are insulated from rate shock, but are left paying for an asset that no longer exists, which may be considered unfair by future ratepayers. In addition, a regulatory asset creates a risk exposure for the utility, as a future commission may choose to cease allowing such payments. As a result, utilities generally do not request—and regulators generally do not approve—amortization periods for regulatory assets that exceed five to seven years. If a plant is retired more than five to seven years early, utilities or regulators generally seek to combine acceleration and regulatory asset concepts, allowing a unit to be retired and recovered after-the-fact over a shorter period. However, this again results in ratepayers being exposed to a substantial rate shock.

**Accelerated Retirement and Earnings Potentials**

Retiring assets without replacing them lowers the future earnings potential of the utility. Because having generation units and other capital assets in its rate base is the key variable determining utility profits, accelerated depreciation of a regulatory asset decreases rate base more quickly than originally planned and eats into earnings. For our example coal plant, the utility would have expected to earn $3.30/MWh on a net present value basis of after-tax future earnings from continued operation of the plant. If the plant were now retired early and replaced in whole with a wind power purchase agreement ("PPA"), and the remaining plant balance recovered via an accelerated regulatory asset over five years, the earnings would drop by more than a half to $1.45/MWh.

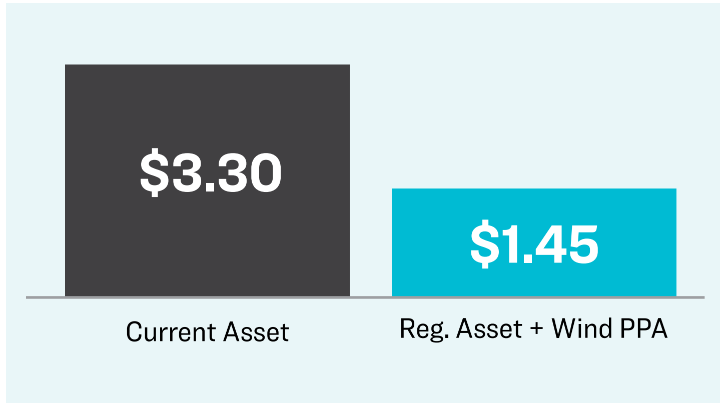
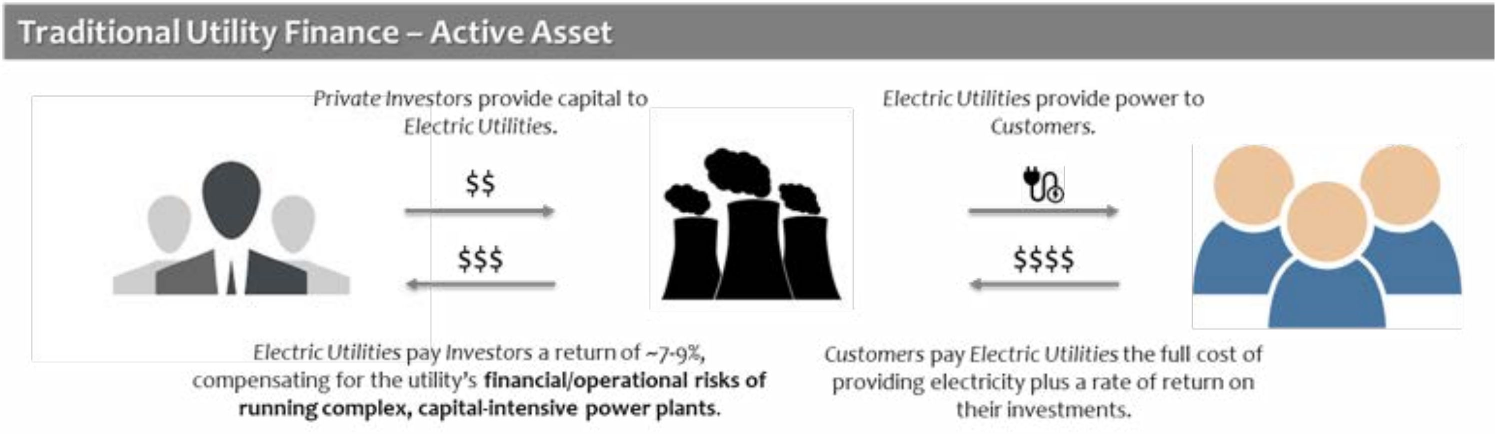


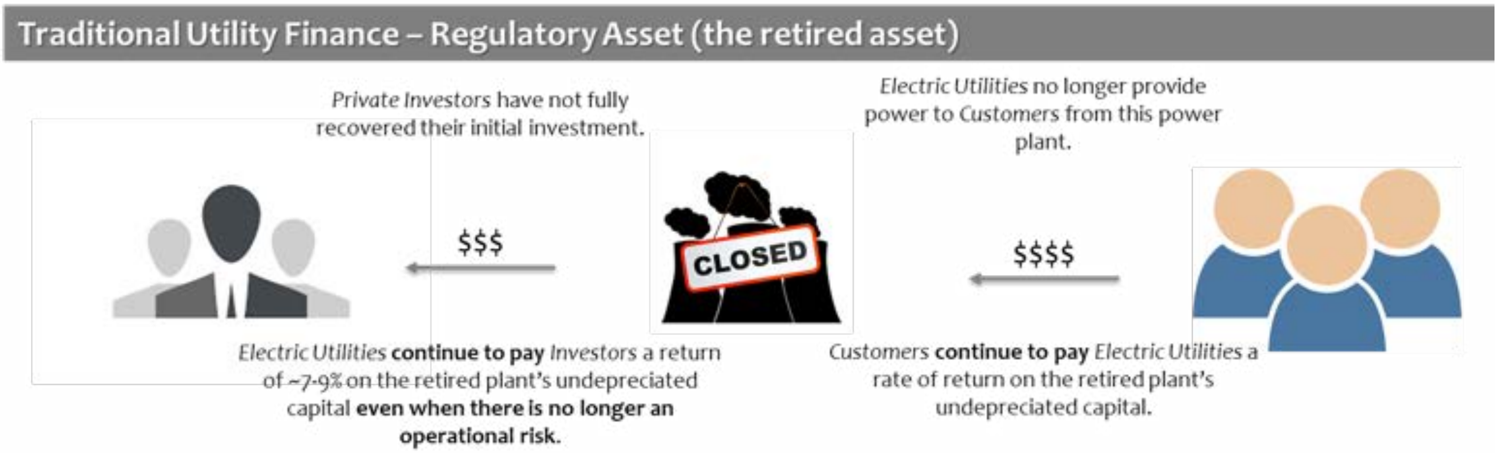

*FIGURE 2. UTILITY EARNINGS*

The company's future earnings depend on the ability to reinvest capital to continue accruing a regulated rate of return. Recalling that our example plant had an expected lifetime of 20 years, investors expected to earn a return on the remaining plant balance for the next two decades, not just for the next five years. Instead of a new capital investment however, the replacement power is a power purchase agreement, which operates as a pass-through cost (i.e. it offers no return to investors). If the utility cannot develop its rate base, its existing equity investors are likely to seek alternative opportunities. As such, the utility's shareholders are not incentivized to advocate for the retirement, even if it is cost effective, unless the utility has opportunities to replace (and preferably increase) the rate base.

## ACCELERATED RETIREMENT AND RATE IMPACTS

An unavoidable consequence of *accelerated* depreciation is the shortened payback period, which in turn requires a short-term rate hike to cover the capital costs of the regulatory asset. Depending on the magnitude of the required recovery relative to the overall rate base, accelerated




depreciation could harm ratepayers—a consequence for which all stakeholders have a limited appetite. Even if the replacement resource is substantially less expensive than the retiring asset, a near-term rate hike is still a barrier. For example, if our example coal plant were retired early, the unrecovered plant balance transferred to a regulatory asset with an accelerated depreciation period, and replaced with inexpensive new wind generation, the near-term cost for that package of assets (e.g., the power plant and its replacement wind) would actually increase from the ratepayer perspective.[13] This happens primarily because the annual cost of amortizing the otherwise 20-year unrecovered plant balance over just five years quadruples the depreciation expenses of asset. In this case, even the significant savings in generation expenses associated with replacing the high operating and fuel costs at $34/MWh (dark blue bar in the first column) with the much lower price of a power purchase agreement (PPA) at $20/MWh (the dark blue bar in the second column) cannot overcome the first-year rate shock from accelerated depreciation.

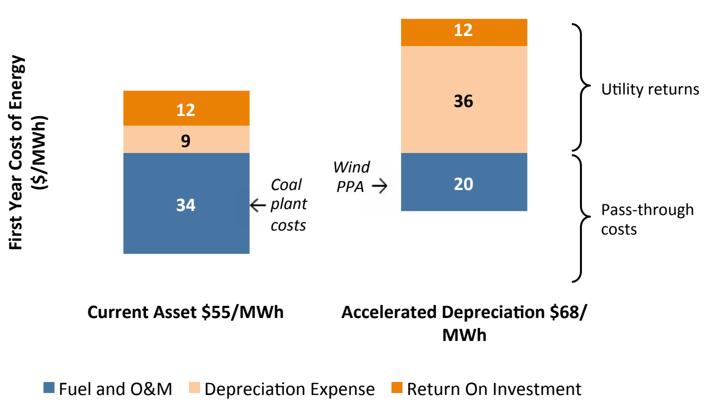



*FIGURE 3. FIRST YEAR REVENUE REQUIREMENT FOR EXAMPLE PLANT BAU AND ACCELERATED DEPRECIATION*

## EARLY RETIREMENT AND COMMUNITY IMPACTS

The early retirement of a large generating asset can result in substantial impact to the local workforce and surrounding communities. There are direct economic impacts on workers at the plant and vendors who supply equipment, services, and raw materials. In rural or economically disadvantaged communities, the property taxes paid by the plant owner, as well as income and sales taxes paid by employees, can be a substantial component of municipal and county budgets. Finally, local employees re-spend locally, and thus retirements may have local multiplier effects and impacts on property values.

In many plant communities, the local power plant is a major provider of jobs and tax revenue; in areas where the coal is also locally sourced, this problem is compounded.

For instance, in Moffat County, Colorado, six of the top ten taxpayers are mine operators and utilities with interests in the local coal plant. These six taxpayers account for 42% of the county's tax base, providing roughly $5.3 million annually to the local school district.[14] And while replacement energy options may have very positive employment, tax and local revenue impacts, those impacts may not be in the same location or occur at the same time as the retirement, causing community stress.

### EARLY RETIREMENT AND RELIABILITY

The physical constraints and reliability needs of the electricity grid itself may also act as a barrier to early retirement of specific plants, especially when variable renewable energy sources are foreseen as replacements for the retired generation. The retirement of some individual assets in specific grid topographies may significantly affect system operation, adding costs at a system level that were not captured in historical operating expenses of plants. The appropriate diagnosis of reliability challenges—as well as the potential range of solutions for addressing them—generally requires detailed system production cost and dispatch modeling. In general, at the levels of penetration of variable generation in balancing areas across the U.S. today, the cost of addressing any such challenges have has been estimated in renewable integration studies to be relatively small, less than $5/MWh.[15]

## 3. OVERVIEW OF UTILITY FINANCING

In traditional cost-of-service regulation, investor-owned utilities are allowed to charge customers a rate, set by regulators, to match the cost of providing service. The rate is typically set such that the utility has the opportunity to earn a reasonable rate of return on the capital it invests on behalf of ratepayers, or "rate base." Utilities typically finance their capital expenditures through a combination of corporate debt and equity, roughly in equal measure. Most vertically integrated electric utilities have an allowed rate of return on capital of between 7-9%, set by regulators.

What regulators actually adjust is the allowed return on equity, or the margin that can be earned by the equity investors. The return on equity, typically between 9-11% on an after-tax basis, is generally based on financial analysis of the historical cost of equity for comparable companies with similar risk profiles and engaged in activities that are similar in their complexity to generating and delivering power. In other words, a utility's return on equity is benchmarked to the historical returns demanded by equity investors as reflected in their share price, earnings, and dividend history. Regulators have the opportunity to adjust the equity return relative to the benchmark. The return rate on equity may be adjusted because the utility has equity costs and risks that differ from its peers, because current equity market conditions no longer match historical average conditions (i.e., regulatory lag), or because the regulators are seeking to signal the utility through a positive or negative adjustment.[16]

The remainder of utility financing is achieved through corporate bonds, or debt. Utilities always aim to achieve credit ratings for their debt issuance that are at or above the "investment grade" threshold (roughly, at or above a Moody's rating of Baa3 or S&P's BBB-).[17] Debt that is rated below investment grade generally faces a substantial increase in financing costs. Long-term, investment grade debt currently features interest rates between 3-6%. The interest rate depends crucially on the specific credit rating achieved (from Baa3 up to Aaa) as well as other characteristics of the debt such as its seniority (i.e., the specific priority of the claim of a given debt issuance on various streams of corporate cash flows) and its security (i.e., the type of lien on and value of any property pledged as collateral provided as security to debt-holders).

In addition, regulators have discretion over whether to allow utilities to recover various costs and can make decisions more generally that impact the timing, size, and certainty of the revenues the utility is allowed to collect from its customers. These decisions can significantly impact the cash flows available to the utility to service its debt, so regulatory risk is also a key determinant of the credit rating of utility debt.

The allowed rate of return—i.e. what the utility actually charges ratepayers for capital expenses—is a blend of the return on equity (9-11%) and debt rate (3-6%). The fraction of equity versus debt, or the capital structure of the utility, is also subject to oversight by regulators and is influenced by the choices they make. In general, utilities seek to balance the risks of debt and equity.

On a superficial level, regulators may desire that the utility borrow using lower-cost debt to drive down the cost of capital. However, as a company becomes more "leveraged," increasing its debt levels relative to equity, the risk to equity investors (i.e. shareholders) increases.[18] A utility might reasonably demand that its equity investors be compensated for this higher risk by increasing the return on equity, which may undo the desired lower cost of capital. Further, deeper leverage leaves less of a margin of error for debt repayment, leading to lower debt ratings and a higher cost of debt.[19] As a result, regulators seek to balance the reduced cost of capital from debt borrowing with the benefits of an equity buffer that mitigates the risk of unanticipated rate hikes.

Utility management may have a different view on the optimal capital structure. Investor-owned utilities have a fiduciary responsibility to achieve maximum value for shareholders while minimizing the risks they face. The value of a utility is most closely tied to the return on equity the utility can achieve (relative to the cost of equity it faces in capital markets) as well as to market perceptions regarding the level of growth in earnings per share that they can reliably expect. As discussed above, a utility's earnings are tied to the capital in rate base. As long as the allowed *return* on equity exceeds the utility's cost of equity (as is generally the case in low interest rate environments), utility management has the incentive to grow the rate base through incremental capital additions. Of course, they seek to do this while minimizing perceptions of risk that could raise their cost of debt. In general, the optimal capital structure that a utility would target will not necessarily be aligned with that desired by a regulator.

As a result, the actual capital structure that any given regulated utility employs will necessarily reflect a compromise that involves some give and take between utilities and regulators—and the customers that both serve. The possibility of electric generation transition—and the challenge of asset stranding in particular—can significantly shift this balance for both utilities and regulators. The possibility of future ratepayer savings from an energy transition *should* drive regulators to seek greater investments in clean energy—but only if current ratepayers' costs are not impacted. On the other hand, the specter of stranded assets affects investor expectations of debt risk and the potential of impaired earnings growth for equity investors. A critical question, then, is how this balance could be shifted to address the needs of all stakeholders—and whether new financial tools can help catalyze such a shift.

## 4. EXCESS COLLECTION IN RATES

Excess collection in rates can create opportunities to achieve rapid electric-sector transition. On occasion, utilities collect customer funds for some specific purpose authorized by their regulator but find later that those funds are no longer required for their originally intended purpose. Recent examples include collections for corporate tax that exceed actual tax due, or instances where forecasted incremental renewable costs exceed actual costs incurred. Regulated utilities typically have their rates adjusted to meet actual expenses incurred; in over-collecting, the utility incurs a regulatory liability and typically must return over-collected revenues to ratepayers. However, rather than simply returning excess revenues, over-collections can be repurposed to address asset retirement and community transition needs. For example, where a utility has collected excess revenues for a specific purpose there may be opportunity to re-purpose the excess monies towards mitigating customer rate shock from accelerated depreciation of an uneconomic plant. One such recent example is the excess collections realized from federal tax reform. While we describe the impact of this particular tax reform, the general principle is applicable to other excess collections.

### EXCESS TAX COLLECTIONS FROM FEDERAL TAX REFORM—DIRECT IMPACTS

Recent federal tax reform has made excess collections of taxes a pressing issue. The 2017 tax reform lowered the corporate federal tax rate from 35% to 21%. Regulated utilities are compensated for their tax expenses through customer rates, which are adjusted in periodic regulatory proceedings ("rate cases"). Utility rates that were set before the passage of tax reform would over-collect tax expenses unless the rates were adjusted subsequently to the passage of the tax reform bill.

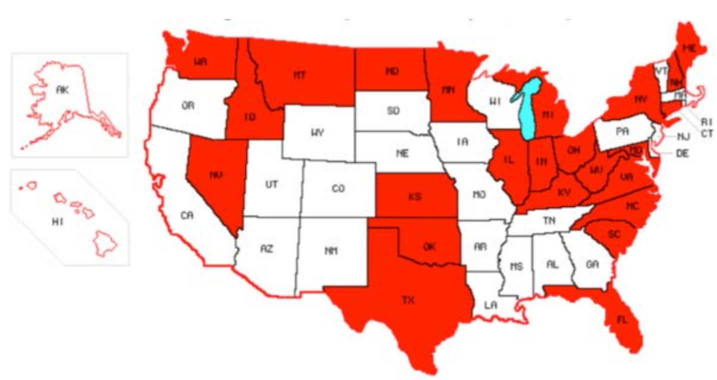


*FIGURE 4. STATES WITH ANNOUNCED TAX REFORM*

Within a month of the passage of tax reform in December 2017, more than half of the states had announced regulatory proceedings to address the consequences for utility customers.

Regulators have many options for how to address over-collection. If rates are not adjusted downwards, the utility's top-line revenues will remain as before tax change. If expenses do not increase correspondingly, the result will be higher utility net income and an inflated return on equity (see the second column in Table 1, below), a situation generally not acceptable to consumer advocates, large users, or regulators.

The simplest option a regulator may choose is to adjust ratepayer tariffs downward to reflect the reduced tax rate. This adjustment leaves the utility's after-tax net income unchanged (see the third column in Table 1, below). However, the loss of total revenues results in lower total pre-tax income, which can impact the perceived financial performance of the utility.

A utility can (correctly) argue that the downward adjustment to income from tax reform would negatively impact key cash-flow driven metrics (e.g., cash flow from operations, pre-working capital), and in turn harms its credit rating. In January 2018, Moody's credit rating agency, citing the tax reform as "credit negative for investor-owned utilities," changed the ratings outlook for twenty-four (24) utilities and holding companies from stable to negative.[21]

There are potential benefits to *both* the utility and customers to consider alternative uses of such over-collections. One option is to repurpose excess funds being collected to cover tax expenses to accelerate depreciation of uneconomic assets or pay for new clean generation or infrastructure. This could enable early retirement of those assets without an increase in ratepayer collections—but only if the savings are large enough, and as a one-time opportunity.

### EXCESS TAX COLLECTIONS FROM FEDERAL TAX REFORM—INDIRECT IMPACTS THROUGH EXCESS ADIT

When utilities collect cash from ratepayers to compensate the utility for its tax expenses, those collections generally do not correspond to the tax due to the government in that specific year. The primary reason for this mismatch is that federal and state tax law often allow for tax deductions for depreciation expenses in a front-loaded manner, called "Modified Accelerated Cost Recovery System" (MACRS).

For example, a 30-year investment in a new wind asset is depreciated in just five years under MACRS (i.e. for the purposes of calculating federal taxes payable), significantly reducing the tax due to the federal government in those early years. The utility, however, still collects tax on the basis of a straight-line (i.e. 30-year) depreciation basis, resulting in an over-collection of tax expenses in those first five years of the asset's life. The utility records this excess collection as "Accumulated Deferred Income Taxes" (ADIT), another regulatory liability. In effect, ADIT acts as a loan the utility receives from ratepayers.

| | **35% Tax Rate** *Original Customer Cost* | **21% Tax Rate** *No adjustment to rates* | **21% Tax Rate** *Adjusted rates* |
|---|---|---|---|
| **Total Annual Ratepayer Costs** | **$265.90** | **$265.90** | **$259.00** |
| Utility Revenues from Facility | $265.90 | $265.90 | $259.00 |
| O&M Expense | $191.50 | $191.50 | $191.50 |
| **Utility EBITDA[20]** | **$74.50** | **$74.50** | **$67.50** |
| Depreciation Expense | $25.70 | $25.70 | $25.70 |
| Interest Expense | $11.40 | $11.40 | $11.40 |
| **Utility Pre-Tax Earnings** | **$37.30** | **$37.30** | **$30.40** |
| Tax Expense | $14.50 | $7.60 | $7.60 |
| **Utility After-Tax Earnings** | **$22.80** | **$29.80** | **$22.80** |
| **Return on Equity** | **9.80%** | **11.40%** | **9.80%** |

*TABLE 1. ILLUSTRATIVE EXAMPLE OF THE IMPACTS OF TAX REFORM ON UTILITY FINANCIAL METRICS WITH AND WITHOUT ADJUSTMENT TO RATES.*

In most jurisdictions, ratepayers are compensated for this loan at the regulated rate of return—effectively the same way the utility would be compensated for incurring a capital expense on behalf of ratepayers. As a practical matter, the ADIT balance is deducted from the rate base when calculating the utility's allowed return. In later years, MACRS falls off and the actual federal taxes paid exceed the tax expense collected from ratepayers.[22] These under-collections are analogous to principal repayments, reducing the ADIT balance over time until that balance is fully exhausted.

If the tax rate is lowered after an ADIT balance has been created, then the accumulated ADIT will no longer be matched by cumulative future taxes due to government. This means that the ADIT balance will not be exhausted, and the utility will hold "excess" ADIT at the end of the asset's life unless corrective action is taken. In general, excess ADIT is returned in installments so that future ratepayers also benefit. However, there may be compelling reasons to allow utilities to repurpose excess ADIT rather than return it rapidly to ratepayers. ADIT effective acts as a cash balance that the utility can use as capital without the need to approach lenders or equity providers.

With a lower tax rate, future ADIT balances attained per dollar of utility capital investment will be smaller. As a consequence, utilities will need to raise additional capital from other sources, such as public debt or equity markets. That increased demand on debt/equity markets could potentially raise the utility's weighted average cost of capital. Repurposing excess ADIT from past investments, rather than simply returning it to ratepayers, can help provide a rapid and relatively low cost source of transition capital—i.e. capital to accelerate depreciation or build new renewable energy.

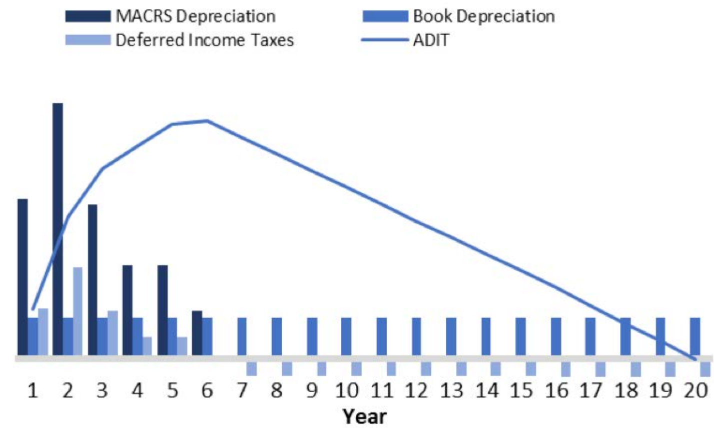



*FIGURE 5. ADIT PROFILE*

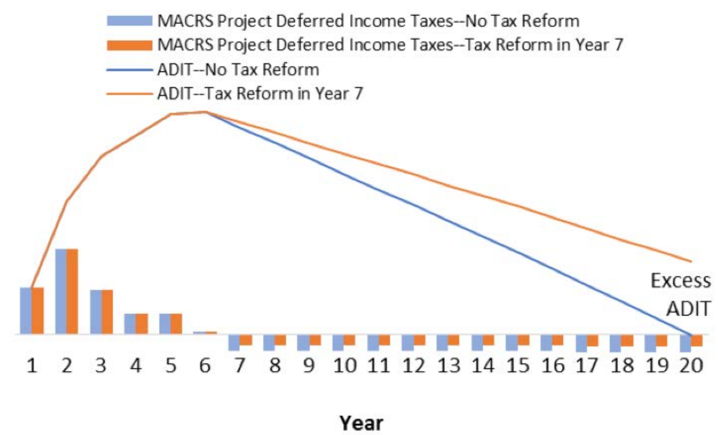



*FIGURE 6. IMPACT OF TAX REFORM ON ADIT*

While this is a promising near-term opportunity, **repurposing of excess collections is not a reliable long-term solution to refinancing uneconomic assets.** Opportunities associated with excess collections, such as federal tax reform, are unlikely to recur with any significant frequency.

## 5. RATEPAYER-BACKED BOND SECURITIZATION

Challenges associated with stranded assets due to electric generation transformation are not new—nor are the potential solutions. The falling cost of gas and advances in efficient combined-cycle gas generation technologies in the 1990s created an upswelling of support for breaking up electric generation monopolies to allow for rapid deployment of these cost-saving generators.

In states that opted for full competitive energy markets (in particular the states within PJM, New York, New England, Texas, and California), utilities were restructured—compelled to separate generation from transmission and distribution services. Investor-owned vertically-integrated utilities faced a similar challenge to today: the book value of generation facilities was often higher than the market cost, meaning that a utility could not recoup its historic investments when selling a generation asset. Utilities subsequently realized substantial stranded asset value. As a result, the regulatory and legislative process implementing restructuring in 21 states allowed for the use of a new financing mechanism—ratepayer-backed bond securitization—that provided utilities compensation for this stranded value.

## WHAT IS SECURITIZATION?

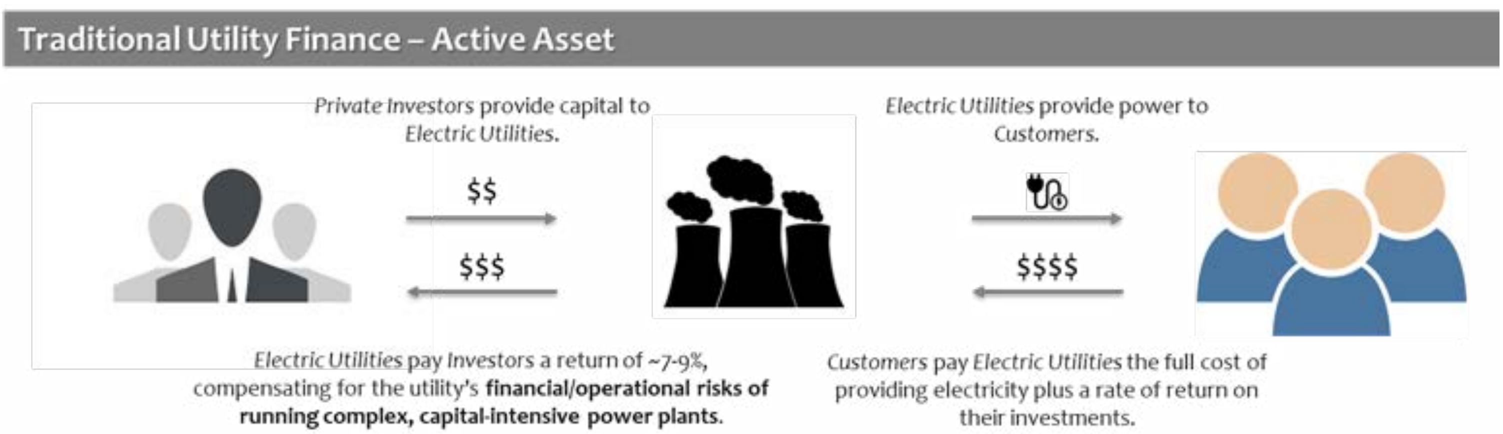
In a broader financial context, securitization is a financing mechanism that pools assets which are expected to generate future revenues and sells them as a private (i.e. not governmental) debt security. A financial institution can achieve very low interest rates on that debt when there is high confidence in future revenues—under four percent (4%) in the current yield environment. "Ratepayer-backed bond securitization" is the securitization of a stream of expected future ratepayer revenues. Securitization is an alternative way for ratepayers to directly raise low-cost debt to address near-term financing needs, cutting out utility's traditional financing role as the middleman between ratepayers and investors.

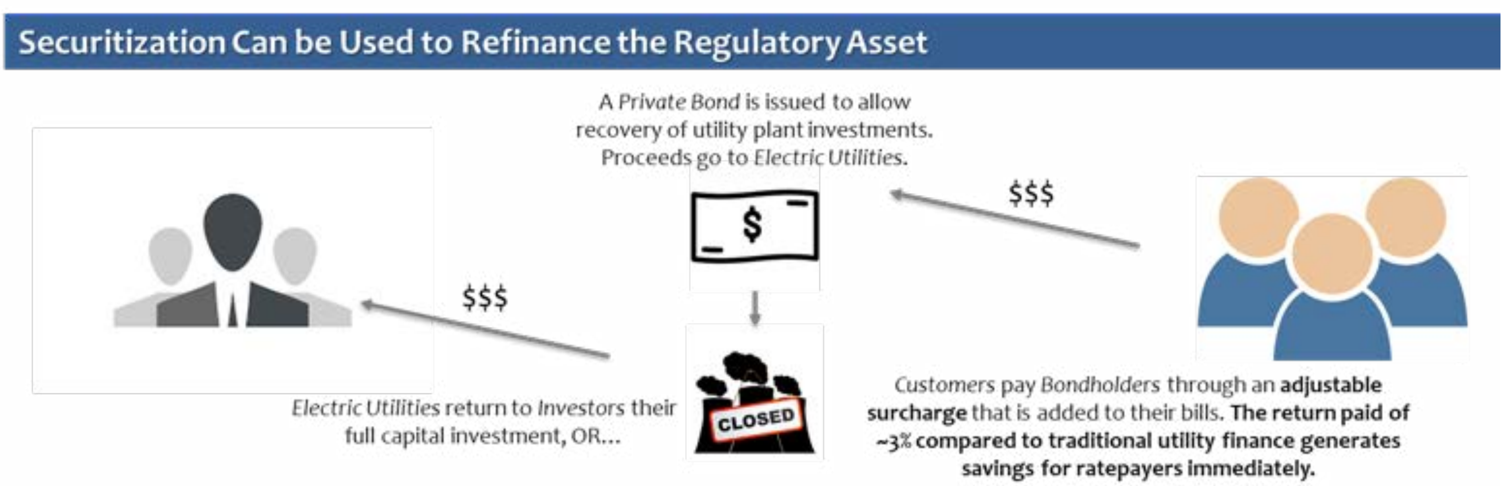
Securitization in the context of the energy transition is the opportunity to "make whole" (i.e. return the capital) the utility owners of non-economic generation, while also minimizing ratepayer impacts. In other words, the utility can ensure that it gets back the stranded asset value of non-economic fossil plants, without imposing higher rates on consumers. Used as part of a comprehensive transition package, securitization can free up funds for clean energy projects while keeping utilities financially viable and reducing ratepayer costs.

In this model, rather than ratepayers paying the utility the revenues required to raise capital from its investors to finance a given project, ratepayers raise the funds directly by issuing a bond to debt investors. Effectively, the ratepayers buy out the utility's debt on a non-economic asset. In normal circumstances, a utility would seek to raise its own funds to be able to build, service, and operate an asset. The utility's cost of capital, however, is relatively high. In ratepayer-backed securitization, the funds are raised through a bond issuance at a far lower rate. In addition, because the securitization mechanism operates through the ratepayers rather than the utility, the funds can also be directed towards assisting workers and communities negatively impacted by early plant retirement.

One critical component of ratepayer-backed bond securitization is that the payment on the bond must be collected from ratepayers, and must be non-bypassable—i.e. there must be zero risk that future ratepayers will not pay the bond. Such guarantees ensure a high bond rating, and low financing costs. This type of irrevocable charge typically requires enabling state legislation, as discussed below.

The graphic below provides an illustration of traditional utility finance and the securitization mechanism. Under



traditional finance, the customers pay electric utilities the full cost of providing service plus a rate of return on investments, which in turn are passed to private investors. In the ratepayer-backed securitization mechanism, the utility is authorized to issue a bond on behalf of ratepayers (through a special purpose vehicle), and the bond is used to cover the utility's stranded asset losses. In turn, the customers pay the bondholders through a bill surcharge, but at a lower overall cost than paying the utility directly.

## ENABLING LEGISLATION

For a securitization to yield the lowest-possible cost of debt, state legislation is usually required that empowers regulators to:

1. Create predictable revenue streams for securitization via dedicated and non-bypassable ratepayer charges that are automatically adjusted in a timely fashion to make principal and interest payments to bond investors;
2. Create a special purpose vehicle (SPV) we refer to as "the securitization company" that is "bankruptcy remote" from the utility,[23] owns the future ratepayer charges, issues the securitization bond, and repays the bond with the proceeds from those charges,
3. Ensure that the collections from the ratepayer charge are the property of the securitization company under a "true sale;" and
4. Pledge not to alter this arrangement for as long as the bonds are outstanding.

Once a securitization mechanism is enabled and approved, the utility continues to play a role by collecting the ratepayer charge on its bills and transferring the proceeds monthly to the securitization company. To be clear, investors of a ratepayer-backed security are purchasing a claim on dedicated future ratepayer charges—and *not* a claim on any past, current, or future physical assets. Therefore, the securitized debt is *not* subject to any risks associated with the prudency of any previous or future utility investments or decisions. Those risks instead remain with the utility and its shareholders. If a future disallowance imperiled the financial viability of the utility, the ratepayer charges dedicated to securitization would not be available to satisfy the utility's creditors.

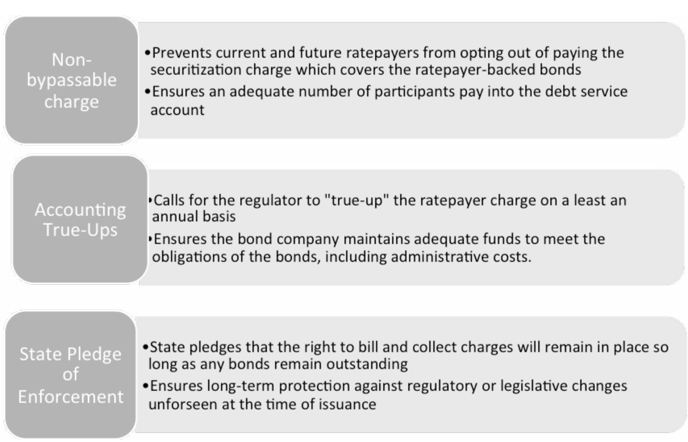



*FIGURE 7. LEGISLATIVE REQUIREMENTS FOR RATEPAYER BACKED SECURITIZATION*

Securitization is not a municipal or state-backed bond. It does not rely on the bonding authority of any government entity, nor does it rely on any government funding or assistance.

Twenty-one states have legislation in place permitting securitization of utility assets, but most are states where prior restructuring required vertically-integrated utilities to sell generation assets. There are relatively few states where vertically-integrated utilities have access to existing securitization legislation, although a number are actively considering such legislation.

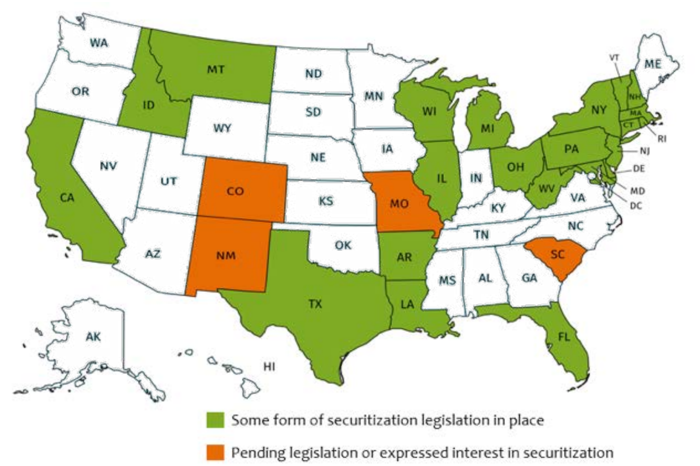



*FIGURE 8. STATES WITH SECURITIZATION*

## THE SECURITIZATION PROCESS

In the securitization process, the utility files an application with the utility regulator to use securitization, and a financing docket is opened. If the application is approved, a financing order is issued which approves the true sale of the asset to the securitization company, the issuance of the bond, and the ratepayer charge. Then, each month a charge is included on ratepayers' bills. These funds are sent to the securitization SPV to make required payments to bondholders. These charges are subject to a true-up to ensure that they are adequate to satisfy bondholders. Once obligations to the bondholders are met, the line item is removed from customer bills and obligations to the SPV end.

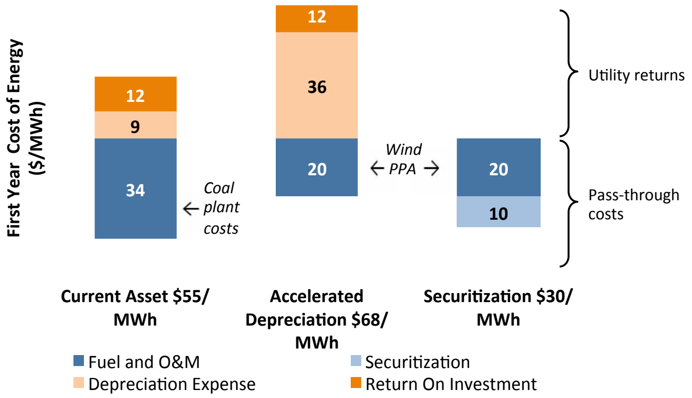



*FIGURE 9. COMPLETE SECURITZATION PROCESS*

## RECENT UTILITY SECURITIZATION EFFORTS

Securitizations, in principle, can be used to finance any number of activities deemed by regulators to be in the interest of ratepayers. However, the legislative vehicle used to authorize the use of securitization will generally constrain the possible uses of the proceeds from securitization.

In recent years, securitization has been employed by:

- Duke Energy (FL) to finance $1.3 billion in assets of a closed nuclear plant in Florida. The bond interest rate is 2.72%, much lower than Duke's cost of capital. Duke calculates the deal saves customers $700 million over 20 years.
- Allegheny Energy (WV) used ratepayer-backed bonds to finance $460 million of pollution control upgrades. The bond was rated Aaa by Moody's, the agency's highest rating.
- Consumers Energy (MI) received PSC approval to sell $389.6 million in securitization bonds to capture the unrecovered net book value of 950 MW of coal-fired capacity retired in 2016.

## MITIGATING RATEPAYER IMPACTS WITH SECURITIZATION

Securitization offers the opportunity to mitigate the rate shock of accelerated depreciation, harness lower cost clean energy projects, and reduce ratepayer costs.

Returning to our example early retirement plant: suppose that the utility files an application with its regulator to retire the plant now, and use securitization to address the $433 million in stranded investments. If the regulator approves the application, it would issue a financing order creating a ratepayer charge (in this case, over 20 years), and a bond would be issued to be repaid with those charges. In our example case, the plant also faces $58 million in near-term decommissioning costs, which are included in the bond. Because our example enabling legislation allows us to tap this low cost financing for other related costs, we also include a community transition fund. In this example, we assume that 15% of the savings from securitization, or $25 million, are channeled to addressing community and worker transition challenges. All told, the bond issuance is assumed to be sized at $515 million to cover all these needs.

So how does this hypothetical use of securitization address the rate shock for ratepayers? Figure 10 shows that securitization eliminates the immediate rate shock from accelerated amortization of a regulatory asset. In the accelerated depreciation case, ratepayers saw an overall first year rate increase, even though they replaced a high cost coal plant ($34/MWh) with a low cost wind PPA ($20/MWh). Annual depreciation expense increased to $36/MWh, increasing customer costs. In the securitization case, consumers still tap the lower cost wind PPA, but replace the depreciation and return on investment with a securitization charge ($10/MWh), drastically reducing the rate impact.

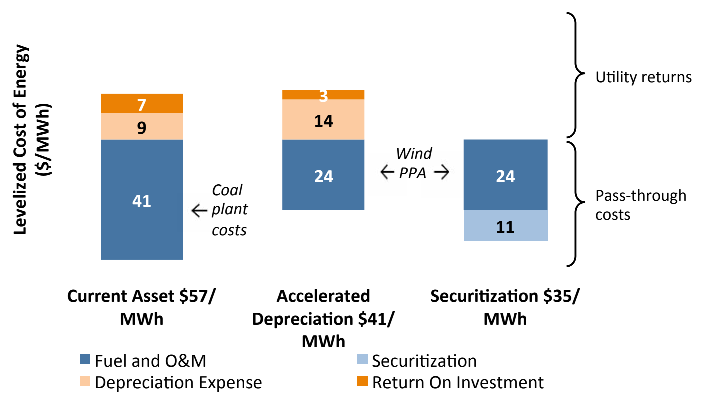



*FIGURE 10. REVE REQ FOR EXAMPLE PLANT, BAU, ACCEL. DEP. AND SECURITIZATION (FIRST YEAR)*

Over the long run, consumers remain better off in this example. Figure 11 shows the levelized[24] cost of energy for the asset and its replacement over a twenty-year period. Over the long run, accelerating depreciation and replacing a non-economic generating unit reduces ratepayer costs (from $57/MWh to $41/MWh). Securitization achieves the same end at a lower cost ($35/MWh). The levelized securitization charge in the third column ($11/MWh) replaces the existing unit's levelized depreciation ($9/MWh) and return ($7/MWh) expenses in the first column.

## UTILITY EARNINGS IMPACTS FROM SECURITIZATION

Savings from securitization are largely achieved by eliminating the capital charges that cover utility return of and return on capital (represented in Figure 10, above, in the bars above the dividing line). In securitization, the utility gets all its outstanding capital back immediately, so the return of its

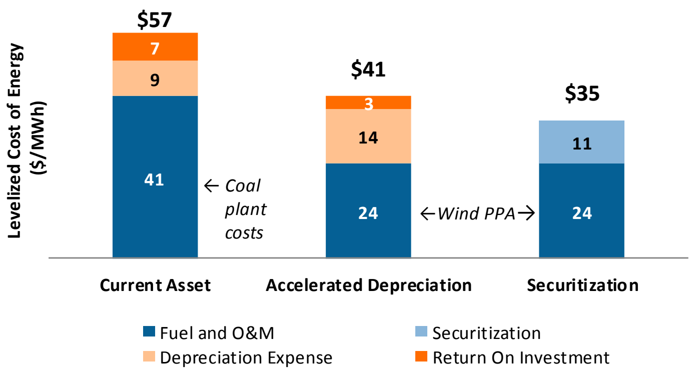



*FIGURE 11. REVE REQ FOR EXAMPLE PLANT, BAU, ACCEL. DEP. AND SECURITIZATION (LEVELIZED COST)*

capital is satisfied. However, the utility's earnings are largely dependent on its return on capital, which falls substantially.[25] Indeed, on a net present value basis (as shown in the utility earnings summary graph below), future utility earnings from securitization alone for the utility fall by over $4/MWh relative to earnings from continued operation of our example coal plant, and $2-3/MWh relative to the use of a regulatory asset via traditional utility financing.

This erosion in future earnings for the utility makes it highly unlikely that a utility would chose to securitize stranded asset balances on its own volition—unless there were other pressing issues or opportunities that could drive the utility to use this tool. One such pressing issue might be a challenge to the financial viability of the utility in the absence of mechanism for rapid recovery of stranded costs, or risk of disallowance for assets no longer considered economically viable. However, regulated utilities are buffered from this risk, in part, by regulators reluctant to risk the financial viability of utilities, or the resultant higher cost of capital. Few regulated utilities face near-term financial distress.

Therefore, securitization alone may not garner significant

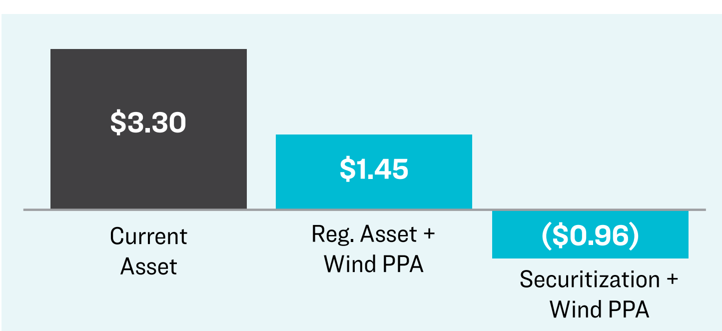



*FIGURE 12. EXAMPLE OF UTILITY EARNINGS (NET PRESENT VALUE) WITH SECURITIZATION FOR STRANDED ASSETS AND A POWER PURCHASE AGREEMENT FOR REPLACEMENT POWER*

interest from utilities. However, combining the release of capital funds through securitization with re-investment in low cost renewable energy, combined with attractive production tax credits offers an attractive, near term opportunity.

## FUNDING COMMUNITY TRANSITION THROUGH SECURITIZATION

Thanks to a lower cost of capital and an extended repayment period, securitization generates savings on a net present value for ratepayers. While the value of savings are transaction-specific, we estimate that, on average, every $100 million in coal plant retired through securitization can unlock around $60 million in avoided capital costs. These savings can either be returned to consumers, or can be used for transition assistance for workers and communities adversely affected by plant retirements, or both.

Securitization can be structured in such a way that savings can be shared with workers and communities impacted by the plants' closure. For example, if 15% of the savings from securitization were set aside for transition assistance, on average, for every $100 million in net plant balances, on average $6 million could go to impacted workers or communities. The amount of transition assistance made available from securitization increases with the net plant balance and remaining life of the asset, so this approach can provide transition resources that are automatically scaled to the size of the shock that a given community faces from early retirement. This type of transition assistance can be substantial: in our example plant, harnessing $25 million towards transition assistance could provide the equivalent of a two-thirds salary for five years for over ninety employees.[26]

## SECURITIZATION AND CREDIT RATINGS

For accounting purposes, utilities may consolidate the securitization bonds as long-term debt on balance sheet; under Internal Revenue Service Revenue Procedure 2002-4911 (Rev. Proc.02-49), this is necessary to avoid immediate recognition of income from the securitization of future ratepayer charges.[27] The increased debt load adversely impacts various metrics used by credit rating agencies to grade a utility's creditworthiness, including:

- Cash Flow from Operating Activities ("CFO") pre-Working Capital + Interest / Interest;
- CFO pre-Working Capital / Debt;
- CFO pre-Working Capital Minus Dividends / Debt; and
- Debt/Capitalization

On net, though, securitizations tend to be credit rating positive, because rating agencies treat the securitized debt as an obligation of the SPV,[28] and because securitization completely eliminates the risk of disallowance or incomplete recovery of a stranded asset.

## 6. FINANCIAL TOOL: SECURITIZATION + CAPITAL RECYCLING

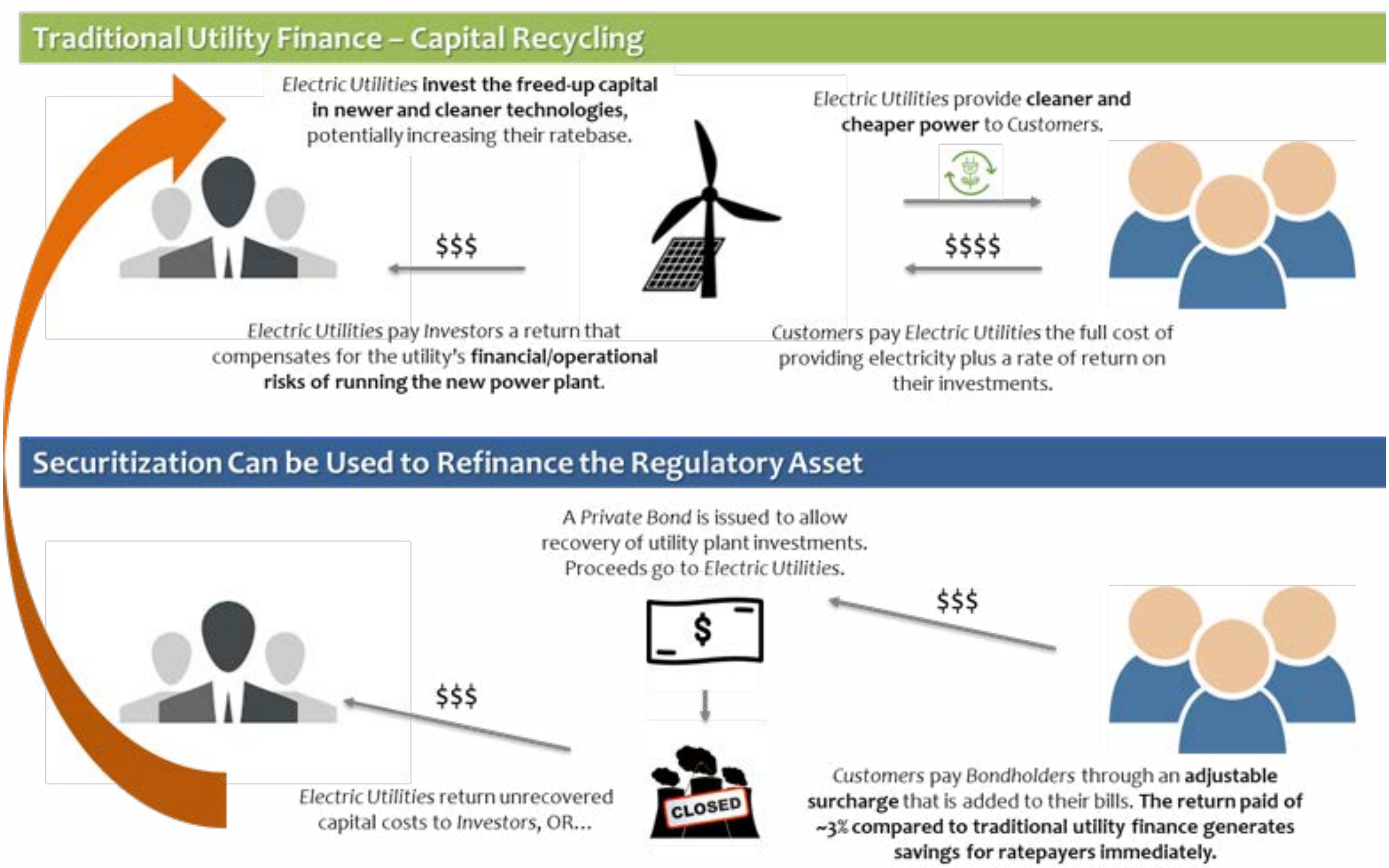
By definition, shuttering an uneconomic coal plant and replacing its marginal costs with a cheaper all-in PPA will provide benefits to ratepayers beyond the refinancing savings achieved through securitization. PPAs, however, are pass-through costs that do not provide profits to shareholders.

Better outcomes for shareholders—and ratepayers—are possible when a utility recycles bond proceeds into renewable assets on its balance sheet: a fuel-for-steel swap.

Renewable generation is far more capital intensive than fossil plants capable of equal output, but requires far less annual expense for fuel and operations. When we compare new renewable projects to substantially depreciated fossil plants, the potential to increase capital return is substantial. As discussed earlier, utility earnings are essentially the risk-adjusted return on the equity fraction of capital in rate base; therefore, deploying capital is generally a profit-enhancing strategy. A utility that is able to offer renewable energy and storage in place of existing fossil generation redirects dollars from pass-through fuel purchases towards capital projects. This swap aligns utility and ratepayer interests: ratepayers see lower energy costs, while utilities increase earnings potentials. In some cases, utilities may also be able to acquire lower cost financing than independent producers.

The expected phase-out of federal tax incentives for renewable energy justifies urgency in laying the foundations for securitization and subsequent capital recycling.

The graphic below provides a summary of how capital recycling can be paired with securitization. As before, the regulatory asset is refinanced through the ratepayer-backed securitization bond. However, in this case, the utility explicitly redeploys the recovered capital from the early retirement of uneconomic assets, and use the proceeds to finance the deployment of clean, cheap replacement power.



The replacement power is now placed in rate base, providing the opportunity for a return, while still meeting ratepayer needs.

Returning to our plant securitization example, we can demonstrate the impacts of capital recycling on utility earnings and ratepayers. Instead of procuring replacement generation through a 20-year PPA with a wind developer, this example allows the utility to own the wind asset as a cost-of-service regulated asset in rate base—a direct use of the dollars recovered through securitization.

In this example, we assume that a new $870 million wind asset is financed entirely through traditional utility financing mechanisms, and that it earns a return equal to the allowed rate of return for the utility. Due to early retirement and securitization, the utility lost $433 million in its rate base, and lost the associated future earnings. However, it recovered $433 million in cash from the proceeds of the securitization bond issuance.[29] The utility is able to turn around that capital to finance the new wind asset, effectively "recycling" its capital from the older fossil asset into a new, clean asset—and more. That is, the utility has been able to grow its rate base from $433 million to $870 million, an increase of $437 million using securitization and capital recycling. In this transaction, ratepayers realize substantial savings and the utility grows earnings, making a "fuel for steel" substitution (i.e. replacing high cost fuel-intensive resources with more capital intensive clean energy projects).

As shown in Figure 13, below, the pass-through costs associated with the wind PPA in the third column[30] is, in this case, replaced with the capital and operating costs for utility-owned wind in the fourth column. Relative to purchased power, this results in additional ratepayer savings both in the first year and over the long-term due to improved rate-of-return project financing.

This example assumes that the utility procures wind to own and operate at costs (i.e., capital and operating expenses) comparable to that of independent generators, but at a more attractive cost of capital. In this example, the securitization plus capital recycling option is also a least-cost option for ratepayers. In total, we transition from a first-year "business as usual" ratepayer cost of $55/MWh, largely driven by fuel and operational costs, to a securitization with capital recycling utility-owned wind at $24/MWh. In the later scenario, about half the revenue requirement is driven by the securitization bond, and the remainder is largely capital invested by the utility to meet customer needs.

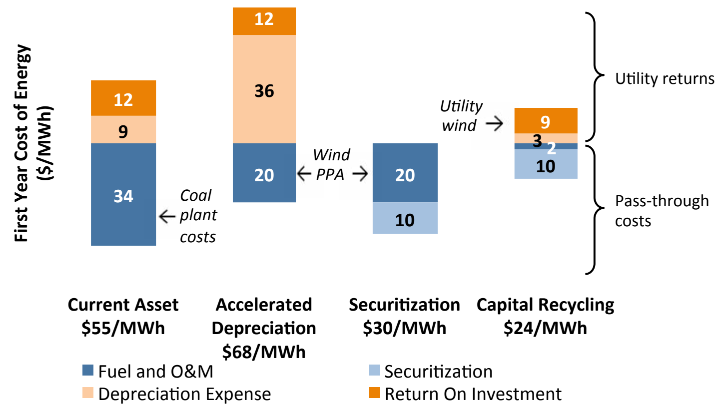



*FIGURE 13. REVENUE REQUIREMENT FOR EXAMPLE PLANT UNDER BAU, ACCELERATED DEPRECIATION, SECURITIZATION, AND SECURITIZATION PLUS CAPITAL RECYCLING (FIRST YEAR)*

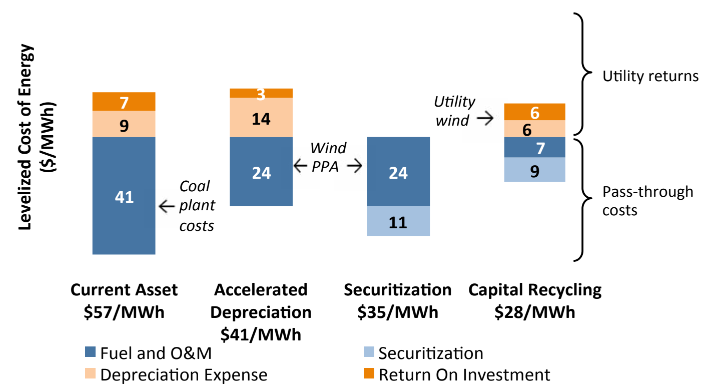
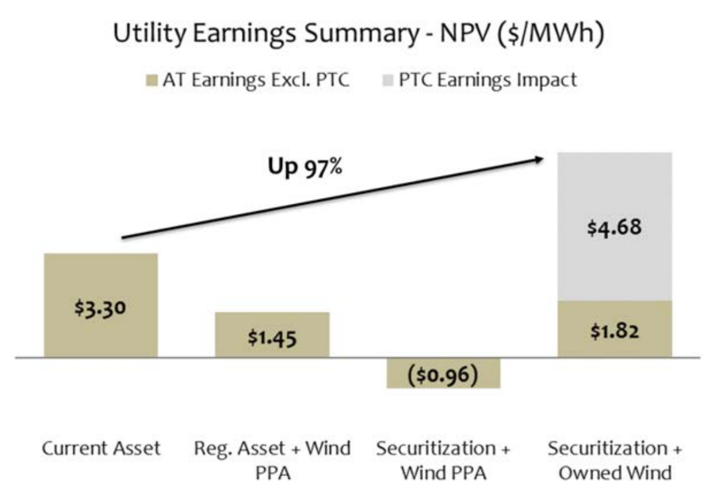



*FIGURE 14: REVENUE REQUIREMENT FOR EXAMPLE PLANT UNDER BAU, ACCELERATED DEPRECIATION, SECURITIZATION, AND SECURITIZATION PLUS CAPITAL RECYCLING (LEVELIZED COST)*




Source: EIA, FERC, company data, CPI analysis

*FIGURE 15. EXAMPLE OF UTILITY EARNINGS WITH SECURITIZATION FOR STRANDED ASSETS AND SELF-BUILT WIND FOR REPLACEMENT POWER. NET PRESENT VALUE ($/MWH) (AT = AFTER TAX)*

This alternative financing scenario is particularly attractive in early years, but its benefits extend through the life of the instrument. As shown in Figure 14, the long-run costs of this scenario are, on net, about half of the costs of the business-as-usual scenario.

Recalling that the wind project is nearly $900 million, while our undepreciated plant was only $400 million, how do we yield these substantially lower ratepayer costs? Several factors are at play. First, the near zero marginal cost of wind avoids the substantial fuel expense of the current asset. Second, securitization shrinks the impact of the remaining capital balance at the fossil plant. And finally, the federal production tax credit ("PTC") in effect subsidizes consumers by lowering the revenue requirement.

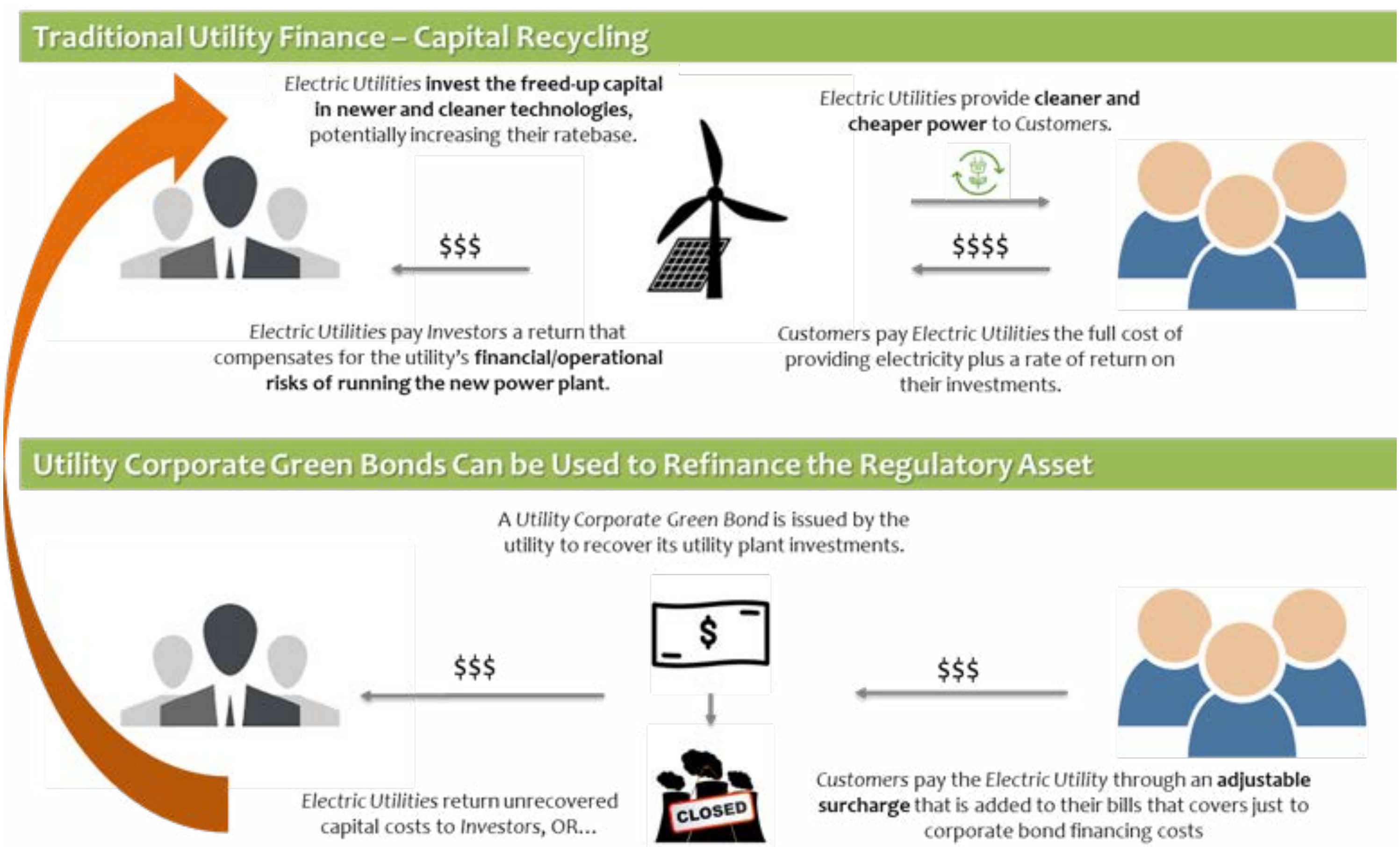
The PTC, when used by a utility to self-build wind, also provides utility earnings. Figure 15 reveals that, on an after-tax basis, Securitization + Owned Wind delivers the largest earning of all the scenarios, a total of $6.46/MWh on an NPV basis over 30 years, with more than 70% coming from ten years of monetization of the PTC.[31]

## 7. GREEN BONDS AND TARIFFS

One set of emerging financial tools available to utilities to lower the cost of retiring uneconomic coal plants is through green bonds and green tariffs. In both cases, the utility uses standard financial mechanisms linked to environmental attributes which may in turn attract lower cost financing. Neither of these mechanisms have a substantial history, but represent a new wave of harnessing finance to transform the energy sector.

### RETIREMENT-LINKED GREEN BONDS

A green bond is a standard bond imbued with a specific environmental characteristic, for example a commitment to reduce emissions or other toxic pollutants to a verifiable extent. For example, a green bond issued for a wind project may carry a specific expectation to displace a certain tonnage of carbon dioxide emissions.[32] These bonds are potentially attractive to investors or corporate buyers with sustainability commitments. A green bond issued to support the retirement of a coal plant could effectively guarantee avoided coal-based emissions on par with either recent historic emissions or reasonably expected going-forward emissions. Investors looking to quantify investments in sustainable bonds, or looking to offset specific emissions



could find verifiable emissions reductions in a coal retirement bond.

In execution, a green retirement bond is similar to securitization, without the sale of assets or legislative protection on the ratepayer charge. The utility issues a bond to refinance the remaining asset balance on an uneconomic plant, plus any funds needed for transition assistance or physical dismantling of the plant net of any salvage value. The utility would still have to request regulatory relief to allow the bond to be paid through a ratepayer surcharge. Unlike securitization, however, the utility issues the bond, rather than the special purpose vehicle. As a result, the bond is not bankruptcy remote and is not immutable: future commissions could hypothetically reverse course on such a bond (an outcome precluded by legislation in securitization).

Because the green bond represents a utility debt, the price of the green bond is fundamentally determined by the credit rating of the utility. While a securitization bond retains guaranteed ratepayer recovery through legislation, a green bond does not, and will likely incur a lower credit rating and higher debt costs than securitization.

The utility would replace the old capacity with a new utility-owned facility, assuming wind for accounting purposes in this case. The replacement capacity would then be financed, in part, with the proceeds from the green retirement bond, minus amounts allocated for transition assistance and physical dismantling. The utility would raise the additional capital needed for the wind asset with further green bonds and stock issuance in line with the regulator-approved capital structure (e.g., 50% debt, 50% equity).

From a ratepayer perspective, the outcome is a net reduction in rates relative to accelerated depreciation or a regulatory asset, as the cost of debt is likely lower than the utility's cost of capital. However, in terms of leverage, the company has swapped out the equity component of the retired asset for low-cost debt and also borrowed additional funds to cover dismantling costs net of salvage and transition assistance. Thus, the overall capital structure will now reflect a higher fraction of debt than the regulator-approved structure. Credit metrics are affected, while none of the obligations or the cash flows for their repayment are bankruptcy remote. Accordingly, rating agencies are likely to treat green bonds as credit negative for the utility.

## RETIREMENT-LINKED GREEN BONDS WITH CAPITAL RECYCLING

Pairing a green bond with capital recycling at our example coal plant results in a ratepayer cost approximately $1/ MWh higher than securitization, both in the first year and over the levelized cost of energy. . In exchange, the utility, and its ratepayers, need not await the passage of securitization legislation where it is currently unavailable. Unless the approved rate of return changes, utility profits should be essentially unchanged when compared with the securitization approach.

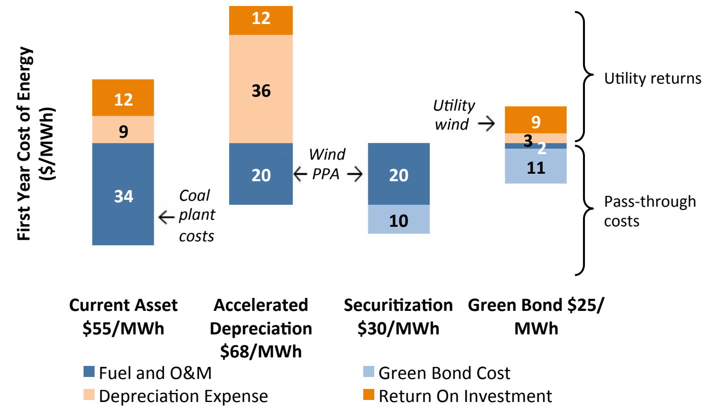



FIGURE 16: REVENUE REQUIREMENT FOR EXAMPLE PLANT UNDER BAU, ACCELERATED DEPRECIATION, SECURITIZATION, AND A GREEN BOND (FIRST YEAR)

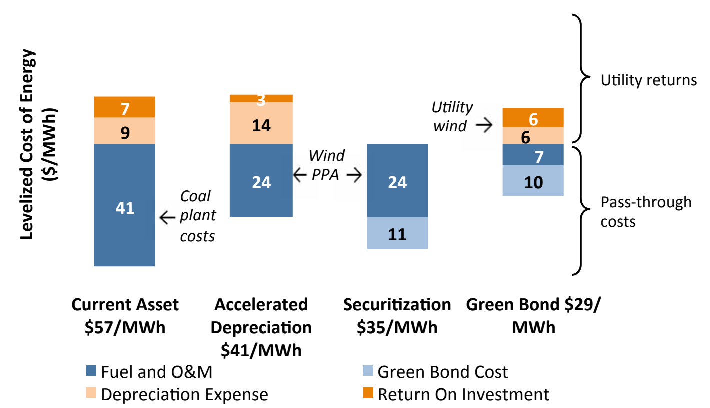



FIGURE 17: REVENUE REQUIREMENT FOR EXAMPLE PLANT UNDER BAU, ACCELERATED DEPRECIATION, SECURITIZATION, AND A GREEN BOND (LEVELIZED)

## RETIREMENT-LINKED GREEN TARIFFS

A green tariff is a mechanism of creating a specialized rate class or energy delivery option for certain large corporate buyers, where the energy procured for and sold to those buyers has specific green characteristics. For instance, large corporate procurers may have self-imposed renewable energy targets that they cannot meet solely with onsite production or through direct purchase. How, and even if, they can satisfy these targets depends heavily on the structure of the markets in which they operate. Certain of these buyers may employ green tariffs, or purchasing specified green energy options directly from their utility suppliers through separate rate structures, usually authorized by the utility regulators.

In states with full retail choice, corporate (and individual) buyers can usually contract directly with renewables developers to purchase energy. However, in some states, retail choice is limited or non-existent, in which case corporate buyers may have to work directly with their regulated utilities to create tailored energy programs.

Green tariffs can enable cost-of-service utilities to deliver renewable energy to customers who may not otherwise be able to access products which satisfy their sustainability goals and cost predictability. Green tariffs take a number of forms, from "green choice" programs to specific rate structures where utilities negotiate and procure renewable energy on behalf of certain customers, and act as the delivery mechanism for that energy.[33] In some cases, green tariff customers pay certain fees to the utility to ensure that other customers are not exposed to higher rates.

In a retirement-focused green tariff, a large corporate buyer could hypothetically acquire a right to energy that specifically replaces a retiring asset. In doing so, the green tariff buyer would support the refinancing of the retired asset (i.e. help pay down the stranded asset cost) and yield the benefits of the low cost and/or potentially tax-advantaged renewable energy which replaces it. While specific green tariffs focused on retirement have not yet been widely introduced, we might term these to have "subtractionality" benefits.[34] Like green bonds, holders of green tariffs can unequivocally demonstrate emissions benefits linked to their actions.

In its purest variant, a green tariff structure combined with the retirement of an uneconomic asset using green bonds would provide corporate buyers with direct access to all the costs, benefits, and risks of a capital recycling strategy:

The green tariff would include the obligation to satisfy the retirement bond as well as the financing, integration, and O&M costs of the replacement generation.

In terms of benefits, participating customers would receive clean energy—and in all likelihood, along with the associated Renewable Energy Certificates (RECs)—at a lower cost than they had previously paid for uneconomic coal generation. Exposure to the capital costs of the retired asset would decline thanks to the replacement of rate of return financing with lower-cost, all debt green bond financing.

Green tariff customers would bear construction and operational risk related to the new assets, and they would also be expected to cover integration costs.

Green tariffs have their own share of challenges, including questions of equity and impact on non-participants. Once a green tariff customer exits, the remaining traditional "brown tariff" customers continue to pay for existing assets, and may not realize the same benefits – or any of the benefits – of the green tariff. Tariffs must be carefully designed to ensure that non-participants are not harmed by the actions of the corporate buyers of the green tariff, including any potential impacts on remaining system costs.

Green tariffs may require an "exit fee" to help the utility offset the costs of generation or power purchase agreements incurred prior to the exit of the corporate buyers (i.e. other stranded assets). Alternatively, some green tariffs are structured such that there is no exit fee, but the choice to acquire energy through alternative means is irreversible.

In light of equity concerns, regulators might object to a green tariff that narrowly channels to participants the full suite of benefits. Instead, green tariff customers and utilities may want to create a solution set where green tariff customers receive environmental or emissions benefits (and the subsequent right to claim a clean energy portfolio or "subtractionality") while sharing the other system benefits—such as lower generation costs—with all ratepayers. Such a solution at worst causes no harm, and at best produces a lower cost of production.

As noted before, securitization and green bonds share a common feature in a separate ratepayer charge to pay back the bond. Because of the dedicated charge and/or the environmental attributes of the bond, respectively, the utility can command a lower rate than traditional regulated return leading to ratepayer savings. In contrast, a green tariff provides the utility the opportunity to solicit private financing from corporate buyers in helping the utility shed non-economic existing units.

| Tariff | Securitization / Green Bond – No Green Tariff | Green Tariff with Exit Fees | Permanent Green Tariff |
|---|---|---|---|
| Type | Mandatory Charge | Opt-in | Opt-in |
| Securitization / Green Bond Charge | Paid by all customers | Paid only by green tariff customers | Paid only by green tariff customers |
| Exit Fees | None | Yes | No |
| Lock-In Period | Securitization / Green Bond Tenor (15-20 yrs) | None | No option to revert to prior tariff |
| Generation Costs Included in Tariff | All generation costs | Replacement clean generation costs + integration costs | Replacement clean generation costs + integration costs |
| Distribution of RECs | All customers | Green Tariff Customers | Green Tariff Customers |
| Transition Assistance Bond Repayment | All customers | Green Tariff Customers | Green Tariff Customers |

*FIGURE 18. COMPARING SECURITIZATION AND GREEN BONDS*

## 8. IN CLOSING

The electric sector in the United States is in a state of nearly unprecedented change. While the electric sector has seen a number of rapid expansions, the emergence of new fuel choices, and the dramatic effects of restructuring, there has not been another period where so much of the existing fleet has been economically challenged from persistently low power prices, flat demand, and the emergence of new low cost energy sources.

Until recently, utilities and regulators have sought to navigate plant closures on a boutique basis, assessing the merits of each plant closure in meticulous detail, and optimizing for the closure of smaller, less efficient power plants. In the interim, the economics of coal have continued to decline dramatically and today's coal-owning traditionally regulated utilities face increasingly difficult questions: how to approach regulators and ratepayers with proposals to close without incurring rate spikes—and while supporting the communities that have grown up around these massive generating stations. Utilities are often loath to broach this question, particularly without significant capital triggers. In part, that hesitation extends from the concern that regulators or ratepayers will seek to disallow costs, leaving utility owners impaired. Regulators find themselves in a stalemate: seek to retire non-economic assets and incur credit risk, or allow non-economic assets to continue operating and punt until another opportunity is availed?

The financial sector may offer a unique opportunity to ease this transition and break the stalemate. Harnessing an assortment of financing tools, from tax incentives to securitization and green tariffs, the sector offers mechanisms to support the utility business model while protecting ratepayers and affected communities.

Ratepayers, utilities, regulators, and financial institutions can work to find creative tools to finance the transition, leading to both stronger corporate utilities, more engaged ratepayers and regulators, and better environmental outcomes.

### ENDNOTES

1. Lazard's Levelized Cost of Energy Analysis 11.0. Note: Does not include federal tax incentives. With the federal tax incentives in place wind and solar are both lower cost than other generation options.
2. U.S. Energy Information Administration. Form 860, March 2018.
3. Rocky Mountain Institute, May 2018. The Economics of Clean Energy Portfolios. https://rmi.org/insight/the-economics-of-clean-energy-portfolios/.
4. Carbon Tracker Initiative. September 2017. No Country for Coal Gen. https://www.carbontracker.org/reports/no-country-for-coal-gen-below-2c-and-regulatory-risk-for-us-coal-power-owners/.
5. Intergovernmental Panel on Climate Change. October 2018. Global Warming of 1.5 °C: An IPCC Special Report. http://www.ipcc.ch/report/sr15/.
6. Bloomberg New Energy Finance. March 2017. Half of U.S. Coal Capacity on Shaky Economic Footing. https://www.bloomberg.com/news/articles/2018-03-26/half-of-all-u-s-coal-plants-would-lose-money-without-regulation.
7. "Merchant" owner means that an owner is not subject to cost-of-service regulation by a state utilities commission, and instead relies on market revenues for energy, capacity, and/or ancillary services.
8. "Regulated" owners are owners subject to cost-of-service regulation by a state utilities commission, wherein costs are recovered through rate case proceedings. Regulated utilities operating in a centralized market region still effectively have their costs covered, in full, by ratepayers.
9. Stranded asset value is the difference between the market value and the remaining capital, or plant balance, yet to be recovered by the utility from ratepayers.
10. Carbon Tracker Initiative. September 2017. No Country for Coal Gen.
11. In states with retail competition, generators and transmission lines are usually privately owned. In those states, the cost-of-service model is still used for the regulation of distribution assets.
12. The utility may have reasons to favor some O&M expense—for example, if they pay for goods or services sourced by a related entity such as a sister company, or if they pay for services provided by company workers. On the other hand, they also have reasons to avoid these expenses, particularly if they could crowd out capital expenditures that could otherwise increase their earnings per share.
13. In this example, replacement energy is purchased under a long-term power-purchase agreement (PPA) and the $433 million outstanding balance is placed into a regulatory asset with an amortization period of 5 years. As an outcome, ratepayers would see an increase for the cost of that procured energy in the first year from $55/MWh to $68/MWh. This type of impact would occur over the five year period.
14. https://www.colorado.gov/pacific/sites/default/files/2017%20Brochure.pdf.
15. See, for example, http://www.synapse-energy.com/project/renewable-energy-integration-costs
16. Such signaling adjustments may reflect a regulators response to poor management decisions or actions, or recognition of positive performance.
17. Moody's "investment grade" scale ranges from Aaa ("highest quality, with minimal risk") to Baa ("subject to moderate credit risk"). Non-investment grade debt ranges from Ba1 ("speculative elements and subject to substantial risk") to C ("poor standing" to default). S&P equivalencies range from AAA to BBB within the investment grade bonds, and BB to C in the non-investment grades.
18. In general, shareholders are last in line to get paid after bond-holders and other debt providers.
19. For example, with more leverage, there is a greater chance that unanticipated costs or investment needs (e.g., due to storm damage), or lower than expected revenues in a given year could lead to a downgrade in a utility's credit rating, thereby increasing the financing costs for any investments that might be required to provide services for future ratepayers.
20. EBITDA: Earnings before interest, tax, depreciation and amortization
21. Moody's. January 19, 2018. Rating Action: Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform.
22. After the fifth year, federal taxes no longer include deductions for depreciation expenses, but utility tax expenses are calculated assuming such deductions continue.
23. Bankruptcy remote means that the company's resources would not be available to the utility's creditors in case of a utility bankruptcy.
24. Levelization: the average annual present value.
25. The utility earns profits through the capital it deploys on behalf of ratepayers. By recalling that capital through securitization, the utility reduces the amount of capital deployed, and hence its earnings.
26. Assumes a 75th percentile annual wage for power plant operators as assessed in May 2017 from Bureau of Labor Statistics (https://www.bls.gov/oes/current/oes518013.htm), endowment earns six percent per year.
27. J. Paul Forester, "Unstranding "Stranded Cost" Securitizations: New Applications for a Proven Technology," (2008), available at https://m.mayerbrown.com/Files/Publication/4cbbcd94-6fb6-42a5-b889-7f595fab14e1/Presentation/PublicationAttachment/be6fd304-233a-4031-b3dc-dfd9ea67b559/ART_STRANDEDCOST_FORRESTER.PDF.
28. Ibid.
29. The $58 million for decommissioning costs is assumed to be spent by the utility on decommissioning, while the $25 million transition fund is assumed to be passed to a transition assistance entity, trust, or non-profit.
30. Purchased wind (PPA) represented as the $20/MWh pass-through-cost in dark blue.
31. Profits slip below $0/MWh in the Securitization + Wind PPA scenario because ADIT from the retired coal plant must still be ratably returned to ratepayers.
32. See, for example, CarbonCount (https://cornerstonecapinc.com/carboncount-a-quantitative-impact-scoring-system-for-green-bonds/)
33. See https://wriorg.s3.amazonaws.com/s3fs-public/emerging-green-tariffs-in-us-regulated-electricity-markets_0.pdf.
34. "Subtractionality" is a notional counterpart to "additionality." Where "additionality" demands that any programs have benefits that are above and beyond those already realized through existing programs, "subtractionality" demands that a program produce a clear net reduction below that which would otherwise be achieved through other means. In this case, rather than increasing clean energy programs in anticipation of displacing pollution-emitting energy sources, a green retirement tariff would seek to unequivocally and directly reduce the use of the emitting energy source.

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# Securitization for Generation Asset Retirement

## Study Group Work Products

2020 NC Energy Regulatory Process

**Contents of this packet:**

NERP FACT SHEET

# EXPANDING SECURITIZATION:

## ACCELERATING THE CLEAN ENERGY TRANSITION AND BUILDING THE NC ECONOMY

**The 2020 North Carolina Energy Regulatory Process prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.**

### WHAT IS THE OPPORTUNITY?

The declining costs of renewable energy and higher cost of operating coal plants relative to other resources has increased interest in retiring coal plants in a low-cost way. However, these coal units remain in the portfolio due to the utilities' need to recover their investment and maintain reliability.

In order to retire coal plants, the remaining undepreciated value must be addressed. Securitization, an innovative financing mechanism, has the potential to create a win-win-win for customers, utilities, and communities. If properly designed, it can be a tool to help facilitate a system-wide transformation - lowering customers' bills, reducing air and water pollution, supporting coal plant communities in the transition, and allowing utilities to reinvest in clean energy to replace lost revenue from legacy coal plant investments. This tool is already available to North Carolina utilities to recover storm costs. Expanding securitization to retire coal plants requires enabling legislation and subsequent implementation to provide creditors with assurances that sufficient funds will be collected to cover the costs of the bonds over its lifetime.

### WHAT IS SECURITIZATION?

Securitization is a refinancing mechanism involving the issuance of bonds to raise funds to refinance the remaining undepreciated value of existing coal plants. The bonds are paid back over time through a dedicated surcharge on customer bills. Because the surcharge is irrevocable and payment to the lender is basically "guaranteed" through the legislation, the bonds can typically be issued at an interest rate even lower than the usual utility bond interest rate. In addition, most major credit rating agencies do not include securitization debt, up to certain limits, in assessing the utilities debt to equity ratio for credit rating purposes. Therefore, the utility can generally refinance the outstanding undepreciated value with 100% securitization financing instead of using its standard combination of debt and equity financing. Both of these factors combined lead to cost savings for customers.

By itself, securitization would translate to a loss in earnings for the regulated utility by reducing the total amount of capital in which the utility is invested. However, securitization can also be paired with utility reinvestment in replacement capacity to maintain reliability. Because this replacement generation would be financed using a combination of debt and equity, this option has the potential to recoup and even grow utility earnings.

### HOW BIG IS THE OPPORTUNITY IN NC?

Duke Energy currently operates six coal plants totaling more than 10,000 MW of capacity. The low cost of natural gas and renewables, along with additional environmental compliance costs, has shifted electricity generation toward cheaper sources of energy in recent years, and the trend is expected to continue as the economic gap widens. Coal plants in the state, originally built to run 75-80% of the time, are now running, on average, only 35% of the time.

Recognizing the significant potential in ratepayer savings, the North Carolina Utilities Commission ordered Duke Energy to evaluate the merits of continuing to operate the coal units by examining the most economic and the earliest practicable dates of retirements. In its 2020 IRP, for the most economic case, Duke Energy recommended the retirement of 11 of 18 units by 2030, even without securitization. For the earliest practicable retirement case, Duke Energy identified that all coal units could be retired by 2030, with one unit converted to natural gas. Securitization should be a tool made available to North Carolina regulators and utilities for cases where it would provide a benefit in customer rates to retire and replace the coal plant.

## HOW DOES SECURITIZATION SOLVE THE PROBLEM?

Through the refinancing of the plant using low-cost debt, securitization has the potential to:

- Create customer savings on day-one and for the remainder of the plant's life due to lower costs of financing
- Create funds for transition assistance to workers and communities affected by plant closures
- Keep the utility whole through reinvestment in replacement renewable generation and/or storage

Early economic retirement of North Carolina's coal plants and replacement with zero emitting resources is estimated to achieve the 70% reduction in greenhouse gas emissions goal specified in the Clean Energy Plan by itself, provided the amount of imported electricity and its carbon intensity remain at or below historical levels.

As North Carolina has a significant amount of coal capacity that could be financed to provide ratepayer benefits, the large amount of generation needing to be replaced must be planned carefully to ensure costs are minimized, utilities are fairly compensated, system reliability is maintained, cleaner technology solutions are deployed, and pollution levels are reduced.

## HOW IS SECURITIZATION DIFFERENT FROM CURRENT OPTIONS TO FINANCE COAL PLANT RETIREMENTS?

The three options currently available to utilities and regulators all have drawbacks and benefits, especially for customers.

Accelerate the retirement of these plants through a rapid return of unrecovered investment (e.g., through accelerated schedule of undepreciated assets than normally allowed over the project life). This helps get the uneconomic plant offline more quickly and likely saves ratepayers money long term. But accelerated depreciation could cause short-term rate spikes, which would impact businesses and low-to-moderate income customers acutely.

Retire a plant and create a regulatory asset**.** This allows the utility to continue to earn a return on a plant that is no longer in service, until the plant is fully depreciated. The downside of this path is that customers are paying for an asset that provides no benefits. For the utility there is also the risk of future disallowance, as there is no guarantee that the public utilities commission will continue to let the regulatory asset be charged to ratepayers.

Disallow the utility from recovering any remaining plant balance. The public utilities commission could decide that the uneconomic plant is no longer "used and useful" and prohibit the utility from recovering any remaining plant balance. This has obvious downsides for the utility, possibly impacting their credit rating, impacting customers over the long run, and potentially chilling interest in future investments.

## HAS SECURITIZATION BEEN USED BEFORE?

In 2019, following the significant disaster recovery and response expenses incurred from hurricanes Matthew and Florence, the North Carolina General Assembly passed SB559 (SL 2019-244) to permit financing for certain storm recovery costs.

Though securitization's proposed use for early coal retirement is recent, it has been used extensively in the past for a variety of reasons – ranging from recovering costs from a damaged plant[1] to financing pollution control upgrades[2] to enabling electricity market restructuring[3]. It is a financial mechanism that Wall Street is both familiar and comfortable with.

Securitization for early plant retirement is already enabled in four states, three of which passed legislation in 2019. PNM Resources in New Mexico is in the process of securitizing its San Juan coal plant[4] and replacing it with a portfolio of renewable energy and storage. Duke Energy Florida securitized $1.3 billion of the remaining plant balance of the Crystal River nuclear plant, resulting in more than $700 million in customer savings. Many other states are expected to introduce supporting legislation in the 2021 session.

*This fact sheet represents the work of stakeholders as of 12/18/2020.*

### About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

### LEARN MORE

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Access the NERP summary report and other NERP documents at:
https://deq.nc.gov/CEP-NERP

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1 *See* https://www.tampabay.com/news/business/energy/duke-energy-florida-customers-will-see-a-new-charge-on-their-bill-starting/2282006/

2 *See* https://saberpartners.com/press/allegheny-closes-pollution-control-issue/

3 *See* http://nescoe.com/resource-center/restructuring-dec2015/

4 *See* https://www.abqjournal.com/1439120/prc-approves-san-juan-abandonment.html

NERP STATUTE COMPARISON

# SECURITIZATION STATUTE COMPARISON

**The 2020 North Carolina Energy Regulatory Process (NERP) prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.**

## INTRODUCTION

Securitization is a financial mechanism allowing bonds to be used to recover undepreciated capital costs of assets and, in some cases, replace other losses of revenue. Securitized bonds, also called ratepayer backed bonds, must be authorized by state legislation. A comparison of securitization statutes that include recovery of undepreciated plant balances and transition assistance for workers and communities affected by early plant retirements can be useful as North Carolina decision makers consider this issue.

Key provisions in legislation typically include:

- Creation of the property right which underlies the bonds
- Definition of allowable uses for the bonds
- Key protections for bond purchasers
- Process for defining bond issuance amount and procedures
- Role of the Public Utilities Commission
- Role of the Public Utility

The North Carolina securitization legislation passed in 2019 contains the basic legal and financial components for creating securitized bonds in statute. However, the only allowable use for the bonds was is recovery of costs incurred from storm damage.

Statutes in other states provide for different or additional uses for the bonds. Specifically, use of bonds for utility capital recovery in the event of early plant retirement and for transition assistance for communities and workers affected by early plant retirements. Statutes permitting these uses also define acceptable capital reinvestment opportunities for the utility retiring an uneconomic plant. Inclusion of a reinvestment or "capital recycling" pathway is a key to securing utility support for securitization legislation with the plant retirement bond use.

Securitization statutes specify the role of the public utilities commission in issuing the financing order for the bonds and its oversight in the bond issuance process. Commission oversight is key to protecting ratepayer interests. Comparisons between the commission's role as defined in the North Carolina Statute, and statutes in Colorado, Montana, New Mexico and Michigan are provided.

## COMPARISON OF SECURITIZATION STATUES

| State | Specified Bond Uses | | | | Utility | Regulator |
|---|---|---|---|---|---|---|
| | *Storm Costs* | *Plant Retirement* | Retire Debt/Equity | *Transition Assistance* | Reinvestment Options | *Strength of PUC Role* |
| North Carolina | **X** | | | | | medium |
| Colorado | | **X** | | **X** | **X** | strong |
| Montana | | **X** | | | **X** | strong |
| New Mexico | | **X** | | **X** | **X** | weak |
| Michigan | | **X** | **X** | | | weak |

## BEYOND STORM COSTS: BOND USES AUTHORIZED IN CO, MT, NM, MI STATUTES

### 1. PLANT RETIREMENT

Using low-interest securitized bonds to replace higher cost utility capital remaining in a retired plant saves ratepayers money. Utility concerns about maintaining rate base often require the legislation include a pathway for reinvestment or "recycling" the returned utility capital into other approved uses. Securitization statutes in Colorado, Montana and Michigan allow securitized bonds to be used for recovering the remaining utility capital invested in a retired power generating station. The New Mexico statute allows bond use for the retirement of a specific power generating station defined in the statute.

**Colorado**
*CO SB19-236, Article 41* – The Colorado Energy Impact Bond Act, part of the Public Utility Commission Sunset/Reauthorization Act

**Allowable Use**: The allowable uses for the bonds extend to the "pretax costs", including unrecovered capitalized cost of a retired electric generating facility that will be retired, and also the "pretax costs" incurred previously related to a commission-approved closure of an electric generating facility retired before the statute was in effect. (CO SB19-236 - page 52, lines 15-24; line 27; page 53, lines 1-3)

**Montana**
*2019 MT HB 467*, placed securitization in Statute.

**Allowable Use**: The two allowable bond uses are the "pretax costs" incurred when the utility retires or replaces electric generating infrastructure or facilities located in Montana, and the "pretax costs" previously incurred related to the closure or replacement or electric generating infrastructure or facilities. (2019 MT HB 467 – page 4, (13)(a))

**New Mexico**
*NM 2019 Energy Transition Act*. Securitization is a centerpiece of this act which also included a renewable portfolio standard and climate goals.

**Allowable Use**: The act allows bond use for the abandonment costs of a "qualifying generating facility", and specifies cap on the amount of money which may be securitized. Other specific dollar amounts for decommissioning and mine reclamation costs, and job retraining are listed as allowable uses. The specificity of the dollar amounts and retirement date for the generating station are tied to a specific plant owned by Public Service of New Mexico (PNM), one of the primary advocates for the bill. The qualifying generating facility language does have some flexibility for application to other plants in New Mexico. (2019 NM SB 489 – page 4, lines 9-24; page 9, lines 6-19)

**Michigan**

*MI 2000, Act 142, Customer Choice and Electricity Reliability Act* included securitization. It was used in 2016 by Consumers Energy for the early retirement of a 950MW coal-fired electric generating station. The bond issue amount was $389.6M. Recently, Consumers Energy filed for a $702.8M financing order related to the early retirement of Units 1 & 2 at the Karn coal-fired generating station.

**Allowable Use**: Refinancing or retirement of debt or equity. (MI 1939 PA 3, Sec. 10h (g); Sec. 10j (1)(a))

### 2. TRANSITION ASSISTANCE: AUTHORIZED IN CO AND NM STATUES

When securitization is used for the early retirement of an electric generating facility, some statutes passed in 2019 added a new use for securitized bonds, providing transition assistance to workers and communities affected by the closure.

**Colorado**

The introduced 2019 bill, HB19-1037, included a formula for sharing the savings realized by refinancing the remaining capital in a retired plant between ratepayers (85% of the savings) and the affected workers and communities (15% of the savings). The savings would be calculated as the net present value of the savings over the tenor (life) of the bonds, compared to the amount ratepayers would have paid to retire the plant without the lower-cost bonds. However, this formula did not survive the legislative process. Instead, the bill includes a simple phase allowing bonds to be used for transition assistance. The decision on the amount of funds for transition assistance will be made by the Commission as part of the financing order.

**Allowable Use**: The statute allows the bonds to be used for "amounts for assistance to affected workers and communities, if approved by the Commission". (CO SB19-236 - page 52, lines 25-26)

**New Mexico**

The Energy Transition act contains very detailed guidelines, establishing three different funds for state agencies to administer transition funding for affected Indian communities, affected communities and workers.

**Allowable Use**: 0.5% of amount bonded is earmarked for the energy transition Indian affairs fund; 1.65% of the bonded amount goes to the energy transition economic development fund; and 3.35% of the bonded amount goes to the energy transition displaced worker assistance fund. (2019 NM SB 489 – page 4, lines 24-25; page 5, lines 1-3; 20-21; SECTION 16, page 40-47)

## UTILITY REINVESTMENT: INCLUDED IN CO, MT, NM STATUTES

**Colorado**

**Reinvestment/Capital Recycling**: Specific opportunities for the utility to reinvest capital recovered from securitizing a retired plant are not listed in Article 41. Instead, reinvestment opportunities for the utility are defined earlier in the statute in the section describing the Clean Energy Plan the utility is required to submit to the Commission. This plan requires the utility to adopt carbon reduction goals, strategies for achieving the goals, projected costs and proposed new clean energy acquisitions required to meet the goals. The utility is awarded up to 50% ownership of the new clean energy acquisitions. (CO SB19-236 - page 17, lines 1-17)

**Montana**

**Reinvestment/Capital Recycling**: The statute provides guidance on how the utility shall expend or invest the funds received from a bond issue. It will first reduce the balance owed on the retired electric generating facility. Following that, the utility may invest or expend funds to own least-cost generation resources, electric storage, network modernization, or to replace any damaged or destroyed electric transmission facilities. (2019 MT HB 467 – page 18-19, Section 18)

**New Mexico**

**Reinvestment/Capital Recycling**: The statute provides a detailed process for how PNM must replace the power from the abandoned generating facility. The specificity is partially a means to replace property tax base for the affect school district and community. (2019 NM SB 489 – page 10, lines 2-25; page 11, lines 1-23)

## ROLE OF THE PUBLIC UTILITIES COMMISSION: STATUES IN CO, MT, NM, MI

Securitization statutes should describe the role of the public utilities commission in issuing a financing order that 1) allows the issuance of bonds; 2) establishes oversight of the bond issuance process; and 3) protects ratepayer interests throughout both processes. The stronger the commission's role, and the more oversight it exercises, the better the outcome for ratepayers.

During the legislative process, the utility has an interest in limiting the commission's role and oversight authority; ratepayer advocates typically push for the opposite outcome, with compromises occurring to achieve bill passage. Among the state statutes we review in this memo, the Colorado statute creates the strongest commission oversight role, followed by Montana, Michigan, and then New Mexico. A key component for empowering a commission to conduct effective oversight is the authority to hire outside financial advisors to assist the commission. Funds for outside advisors or additional staff to manage the bond issuance process may not be covered in a commission's normal staff budget. Statutes typically allow commission expenses related to a bond issue to be covered as a part of the bond issue expenses. If a utility receives a financing order, but decides not to issue the bonds, commission expenses incurred in producing the financing order would have to be paid by the utility, which can recover those expenses in a future rate case.

The existing North Carolina securitization statute provides reasonable oversight authority for the commission. The Commission can hire outside financial advisors, with their costs paid as part of the bond issue. The North Carolina statute, however, does not address the situation of recovery of commission expenses when the utility does not follow through and issue bonds.

**Colorado**

**Public Utility Commission Role**: The Statute gives the Commission the authority to:

- Require the bonds provide maximum net present value savings for ratepayers (CO SB19-236 - page 59, lines 14-27)
- Conduct oversight of how the bond issue will be structured, priced and marketed to achieve maximum savings for ratepayers (CO SB19-236 - page 60, lines 14-22)
- Attach conditions to the financing order to maximize benefits and minimize risks for all parties (CO SB19-236 - page 66, lines 4-8)
- Hire outside financial advisors to assist the Commission in its oversight work (CO SB19-236 - page 67, lines 9-20)
- Require the utility to simultaneously add a negative cost rider to ratepayer bills to reflect the decreased cost of service and counterbalance the bond repayment charge (CO SB19-236 - page 62, lines 19-24)
- Conduct a rule making for how to manage the securitization financing order process. (CO SB19-236 - page 65, line 27)

**Montana**

**Public Utility Commission Role:** The Statute gives the Commission the authority to:

- Require the bonds to provide substantial quantifiable savings for ratepayers (2019 MT HB 467, Section 5 (iv)(c) (I)(ii)
- Include findings determined by the commission to be in the best interests of consumers. (2019 MT HB 467, Section 5 (vii)
- Require the utility to reduce rates simultaneously with the addition of the bond repayment charge on ratepayer bills (2019 MT HB 467, Section 5 (B))
- Hire outside financial advisors to assist the Commission in its oversight work. (2019 MT HB 467, Section 5 (B)(3)(f))
- Conduct a rule making for how to manage the securitization financing order process (2019 MT HB 467, Section 19)

**Michigan**

**Public Utility Commission Role:** The Statute gives the Commission limited authority:

- Oversight to ensure customer savings is weak – savings must be "tangible and quantifiable", but no reference is made to maximize savings or how savings should be calculated. ((MI 1939 PA 3, Sec.10i (2)(b)(c))
- The authority to hire outside financial advisors to assist the Commission in its oversight work is included. ((MI 1939 PA 3, Sec.10i (10))

**New Mexico**

**Public Commission Utility Role:** The Statute gives the Commission very limited authority:

- No oversight to ensure customer savings. Savings are calculated by applicant utility as it deems appropriate, and submitted to the Commission as part of the financing order. (2019 NM SB 489 – page 10, lines 2-25; page 13, lines 17-25)
- Commission has no authority to determine the amount to be securitized for plant retirement or transition assistance. These amounts were determined by the legislature and are in Statute. (2019 NM SB 489 – page 4, lines 9-25; page 40-47, Section 16)
- Commission is required to approve a financing order from qualified applicant utility, if financing order application meets Statute requirements. (2019 NM SB 489 – page 17, lines 7-17)
- Commission does have the power to review and approve replacement generation options. (2019 NM SB 489 – page 10, lines 2-25; page 11, lines 1-23)

# RECOMMENDATIONS

- The North Carolina Storm Recovery Costs securitization statute could be amended to include additional permitted uses for the bonds. Additional uses could include plant retirement costs and transition assistance for affected communities and workers.
- If plant retirement becomes an allowable use for the bonds, the bill should also include guidance on re-investment opportunities for the utility.
- The existing statute permits the Commission to hire outside financial advisors with the costs paid as part of the bond issue. Adding a provision for Commission cost recovery in the event that bonds are not issued by the utility, similar to the language in the Colorado statute, may be helpful.
- The North Carolina statute provides reasonable oversight authority for the commission. Attempting to strengthen commission authority might trigger utility resistance to the bill.

*This fact sheet represents the work of stakeholders as of 12/18/2020.*

## About the North Carolina Energy Regulatory Process

Governor Cooper's Executive Order 80 mandated the development of a clean energy plan for the state of North Carolina. The Clean Energy Plan recommended the launch of a stakeholder process to design policies that align regulatory incentives with 21st century public policy goals, customer expectations, utility needs, and technology innovation. The stakeholder process was launched in February 2020 and has led to policy proposals on energy reform.

## LEARN MORE

Contact NERP Securitization Study Group Leads:
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Access the NERP summary report and other NERP documents at: https://deq.nc.gov/CEP-NERP

NERP ANALYSIS SUMMARY

# GENERATION ASSET RETIREMENT FINANCIAL ANALYSIS

## COMPARISON OF SECURITIZATION AND REGULATORY ASSET TREATMENT: RELATIVE IMPACTS ON RATEPAYER SAVINGS, UTILITY EARNINGS, AND COMMUNITY ASSISTANCE

The 2020 North Carolina Energy Regulatory Process prioritized energy reforms that would drive affordability, carbon-reduction, and align regulatory incentives with policy goals.

## SUMMARY OF FINDINGS

Based on financial analysis performed for a select group of Duke Energy Progress (DEP) coal plants, Rocky Mountain Institute (RMI) finds that securitization (with reinvestment) leads to greater ratepayer savings (in the short and long term) than using regulatory asset treatment as a method for early retirement. Furthermore, securitization with reinvestment provides the utility opportunity for earnings through additions to rate base and could fund transition assistance for impacted communities.

For example, securitizing Mayo (with utility reinvestment) could save ratepayers between $13-19/MWh (or $18-29MM) in the first year and between $3-5/MWh (or $46-96MM) on a levelized basis, compared to a regulatory asset treatment. The utility has a significant earnings opportunity with securitization, though less than through the regulatory asset treatment – up to $600-800MM with the former vs. up to $800-1100MM (on a levelized basis and including tax credits) with the latter. Finally, securitization could result in between $8-15MM in community assistance.

While RMI's analysis shows securitization generating ratepayer savings compared to a regulatory asset treatment, the magnitude of that difference varies. In Roxboro 3, for example, securitization with reinvestment could save ratepayers between $4-6/MWh (or $9-13MM) in the first year and between $17-21MM on a levelized basis, compared to regulatory asset treatment. The earnings opportunity for the utility in retiring and replacing Roxboro 3 is similar for both securitization & regulatory assets – up to $700-800MM. Finally, between $2-4MM in community assistance could be made available for this plant.

The ratepayer savings, utility earnings and community assistance opportunity for Roxboro 4 is similar to that of Roxboro 3, for both securitization and regulatory asset treatment.

## IMPORTANT CAVEATS AND ASSUMPTIONS

RMI's financial model was used to provide *relative* and *illustrative* modeling results – in their current form, the results are not meant to estimate the absolute size of ratepayer savings or utility earnings from any retirement method.

Rather, the results aim to show the tradeoffs (for the utility, customer and community) between two different methods of early plant retirement, and the relative magnitude of the differences in the two approaches.

If a decision is made to investigate the actual implementation of securitization, the analysis would have to be revisited to more accurately account for (among other items):

- The expected 'ramp down' of existing coal plants, prior to retirement
- The sequencing of replacement generation and storage, relative to early retirement
- Implications of early retirement at the fleet level (vs. the individual plant level)

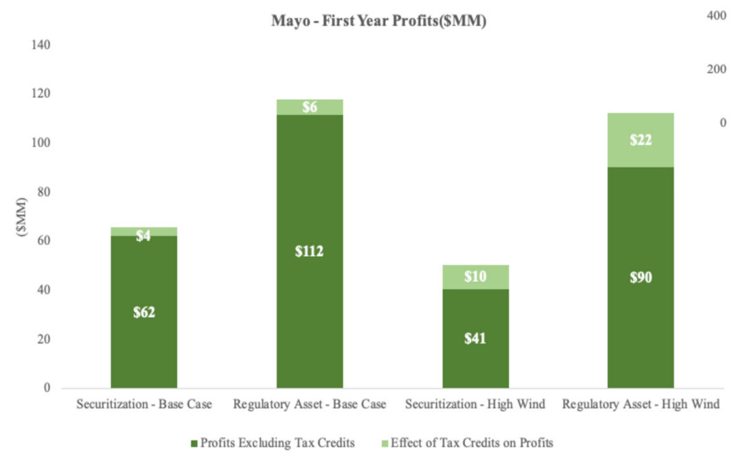
RMI believes that, while the above considerations are critical to implementation, they do not significantly alter the potential *opportunity* presented by securitization for customers, the utility and the community, relative to a regulatory asset treatment.

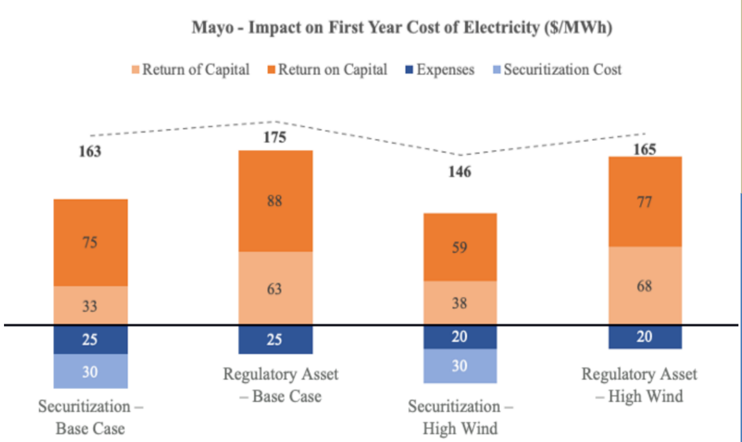
## ILLUSTRATIVE MODELING RESULTS

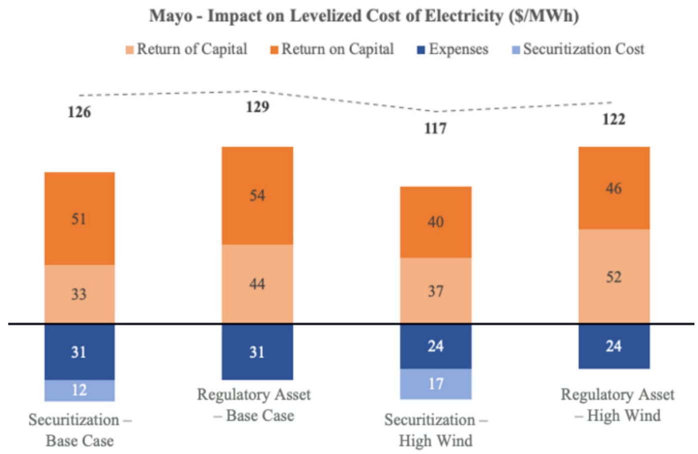
RMI modeled three DEP plants – Mayo 1, Roxboro 3 and Roxboro 4. For each of the plants, two methods of retirement were considered: i) securitization with reinvestment and, ii) regulatory asset treatment.

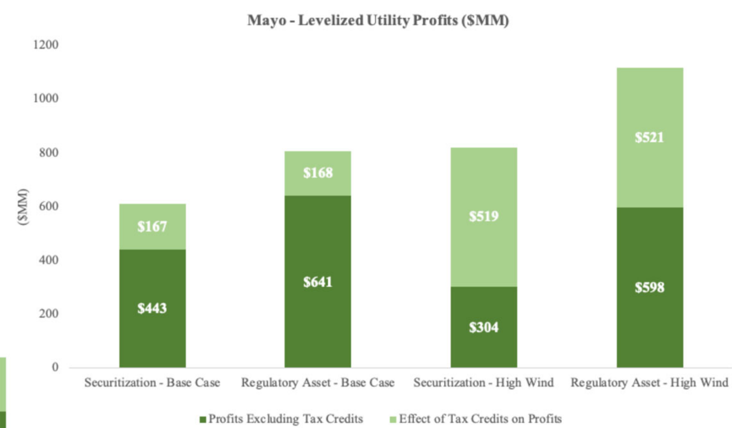
Furthermore, to determine the retirement year and subsequent replacement portfolio for each plant, Scenario A (Base Case without Carbon Policy) and Scenario D (High Wind) from the DEP 2020 Integrated Resource Plan were used.

The results for Mayo 1 are shown below as an illustrative example:

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**GENERAL ASSEMBLY OF NORTH CAROLINA SESSION 2021**

**SENATE/HOUSE BILL XXX**

A BILL TO BE ENTITLED
"AN ACT TO PERMIT FINANCING FOR CERTAIN UNDEPRECIATED UTILITY PLANT COSTS AND FOR TRANSITION ASSISTANCE FOR AFFECTED WORKERS AND COMMUNITIES"

The General Assembly of North Carolina enacts:

**SECTION 1.** Article 8 of Chapter 62 of the General Statutes is amended by adding a new section to read:

"**§ 62-173. Financing for certain energy transition costs.**

(a) Definitions. – The following definitions apply in this section:

(1) Ancillary agreement. – A bond, insurance policy, letter of credit, reserve account, surety bond, interest rate lock or swap arrangement, hedging arrangement, liquidity or credit support arrangement, or other financial arrangement entered into in connection with energy transition bonds.

(2) Assignee. – A legally recognized entity to which a public utility assigns, sells, or transfers, other than as security, all or a portion of its interest in or right to energy transition property. The term includes a corporation, limited liability company, general partnership or limited partnership, public authority, trust, financing entity, or any entity to which an assignee assigns, sells, or transfers, other than as security, its interest in or right to energy transition property.

(3) Bondholder. – A person who holds an energy transition bond.

(4) Code. – The Uniform Commercial Code, Chapter 25 of the General Statutes.

(5) Commission. – The North Carolina Utilities Commission.

(6) Customer securitization savings – The arithmetic difference between the net present value of the costs to customers that are estimated to result from the issuance of energy transition bonds and the net present value of the costs that would result from the application of the traditional method of financing and recovering energy transition costs from customers.

(7) Energy transition bonds. – Bonds, debentures, notes, certificates of participation, certificates of beneficial interest, certificates of ownership, or other evidences of indebtedness or ownership that are issued by a public utility or an assignee pursuant to a financing order, the proceeds of which are used directly or indirectly to recover, finance, or refinance Commission-approved energy transition costs and financing costs, and that are secured by or payable from energy transition property. If certificates of participation or ownership are issued, references in this section to principal, interest, or premium shall be construed to refer to comparable amounts under those certificates.

(8) Energy transition charge. – The amounts authorized by the Commission to repay, finance, or refinance energy transition costs and financing costs and

that are nonbypassable charges (i) imposed on and part of all retail customer bills, (ii) collected by a public utility or its successors or assignees, or a collection agent, in full, separate and apart from the public utility's base rates, and (iii) paid by all existing or future retail customers receiving transmission or distribution service, or both, from the public utility or its successors or assignees under Commission-approved rate schedules or under special contracts, even if a customer elects to purchase electricity from an alternative electricity supplier following a fundamental change in regulation of public utilities in this State.

(9) Energy transition costs. – All of the following:

(a) (i) at the option of and upon petition by an public utility, and as approved by the commission, any of the pretax costs that the electric utility has incurred or will incur that are caused by, associated with, or remain as a result of the retirement of an electric generating facility located in the state.
(ii) as used in this subsection, "pretax costs," include, but are not limited to, the unrecovered capitalized cost of a retired electric generating facility, costs of decommissioning and restoring the site of the electric generating facility, and other applicable capital and operating costs, accrued carrying charges, deferred expenses, reductions for applicable insurance and salvage proceeds and the costs of retiring any existing indebtedness, fees, costs, and expenses to modify existing debt agreements or for waivers or consents related to existing debt agreements.

(b) amounts for transition assistance to affected workers and communities if approved by the commission;

(c) pretax costs that an electric utility has previously incurred related to the commission-approved closure of an electric generating facility occurring before the effective date of this section.

(d) energy transition costs do not include any monetary penalty, fine, or forfeiture assessed against an electric utility by a government agency or court under a federal or state environmental statute, rule, or regulation.

(10) Energy transition property. – All of the following:

a. All rights and interests of a public utility or successor or assignee of the public utility under a financing order, including the right to impose, bill, charge, collect, and receive energy transition charges authorized under the financing order and to obtain periodic adjustments to such charges as provided in the financing order.

b. All revenues, collections, claims, rights to payments, payments, money, or proceeds arising from the rights and interests specified in the financing order, regardless of whether such revenues, collections, claims, rights to payment, payments, money, or proceeds are imposed, billed, received, collected, or maintained together with or commingled with other revenues, collections, rights to payment, payments, money, or proceeds.

(11) Financing costs. – The term includes all of the following:

a. Interest and acquisition, defeasance, or redemption premiums payable on energy transition bonds.

b. Any payment required under an ancillary agreement and any amount required to fund or replenish a reserve account or other accounts established under the terms of any indenture, ancillary agreement, or other financing documents pertaining to energy transition bonds.

c. Any other cost related to issuing, supporting, repaying, refunding, and servicing energy transition bonds, including, servicing fees, accounting and auditing fees, trustee fees, legal fees, consulting fees, structuring adviser fees, administrative fees, placement and underwriting fees, independent director and manager fees, capitalized interest, rating agency fees, stock exchange listing and compliance fees, security registration fees, filing fees, information technology programming costs, and any other costs necessary to otherwise ensure the timely payment of energy transition bonds or other amounts or charges payable in connection with the bonds, including costs related to obtaining the financing order.

d. Any taxes and license fees or other fees imposed on the revenues generated from the collection of the energy transition charge or otherwise resulting from the collection of energy transition charges, in any such case whether paid, payable, or accrued.

e. Any State and local taxes, franchise, gross receipts, and other taxes or similar charges, including regulatory assessment fees, whether paid, payable, or accrued.

f. Any costs incurred by the Commission or public staff for any outside consultants or counsel retained in connection with the securitization of energy transition costs, except as provided in subparagraph (d)(1)c.

(12) Financing order. – An order that authorizes the issuance of energy transition bonds; the imposition, collection, and periodic adjustments of an energy transition charge; the creation of energy transition property; and the sale, assignment, or transfer of energy transition property to an assignee.

(13) Financing party. – Bondholders and trustees, collateral agents, any party under an ancillary agreement, or any other person acting for the benefit of bondholders.

(14) Financing statement. – Defined in Article 9 of the Code.

(15) Pledgee. – A financing party to which a public utility or its successors or assignees mortgages, negotiates, pledges, or creates a security interest or lien on all or any portion of its interest in or right to energy transition property.

(16) Public utility. – A public utility, as defined in G.S. 62-3, that sells electric power to retail electric customers in the State.

(b) Financing Orders. –

(1) A public utility may petition the Commission for a financing order. The petition shall include all of the following:

a. The energy transition costs incurred by the utility and an estimate of the costs that are being undertaken but are not completed.

b. A statement of whether the public utility proposes to finance all or a portion of the energy transition costs using energy transition bonds. If the public utility proposes to finance a portion of the costs, the public utility must identify the specific portion in the petition. By electing not to finance a portion of such energy transition costs using energy transition bonds, a public utility shall not be deemed to waive its right to recover such costs pursuant to a separate proceeding with the Commission.

c. A proposed amount, for Commission consideration, to be included in energy transition costs for use as transition assistance for workers and local governments negatively affected by the retirement of an electric generating facility.

d. An estimate of the financing costs related to the energy transition bonds.

e. An estimate of the energy transition charges necessary to recover the energy transition costs and financing costs and the proposed period for recovery of such costs.

f. An estimate of the quantifiable customer securitization savings resulting from the use of energy transition bonds instead of traditional cost recovery methods.

g. Direct testimony and exhibits supporting the petition.

(2) If a public utility is subject to a settlement agreement that governs the type and amount of costs that could be included in energy transition costs and the public utility proposes to finance all or a portion of the costs using energy transition bonds, then the public utility must file a petition with the Commission for review and approval of those costs no later than 90 days before filing a petition for a financing order pursuant to this section.

(3) Petition and order. –

a. Proceedings on a petition submitted pursuant to this subdivision begin with the petition by a public utility, filed subject to the time frame specified in subdivision (2) of this subsection, if applicable, and shall be disposed of in accordance with the requirements of this Chapter and the rules of the Commission, except as follows:

1. Within 14 days after the date the petition is filed, the Commission shall establish a procedural schedule that permits a Commission decision no later than 210 days after the date the petition is filed.

2. No later than 210 days after the date the petition is filed, the Commission shall issue a financing order or an order rejecting the petition. A party to the Commission proceeding may petition the Commission for reconsideration of the financing order within five days after the date of its issuance.

b. A financing order issued by the Commission to a public utility shall include all of the following elements:

1. Except for changes made pursuant to the formula-based mechanism authorized under this section, the amount of energy transition costs to be financed using energy transition

bonds. The Commission shall describe and estimate the amount of financing costs that may be recovered through energy transition charges and specify the period over which energy transition costs and financing costs may be recovered.

2. A finding that the proposed issuance of energy transition bonds and the imposition and collection of an energy transition charge are expected to provide quantifiable benefits to customers as compared to the costs that would have been incurred absent the issuance of energy transition bonds and a statement of the net present value of those benefits to customers.
3. A finding that the structuring and pricing of the energy transition bonds are reasonably expected to result in the lowest energy transition charges consistent with market conditions at the time the energy transition bonds are priced, and with the terms set forth in such financing order.
4. A determination of the portion, up to 15%, of the customer securitization savings that shall be included in transition bond costs and used to provide transition assistance to workers and local governments negatively affected by the retirement of the electric generating facility.
5. A requirement that, for so long as the energy transition bonds are outstanding and until all financing costs have been paid in full, the imposition and collection of energy transition charges authorized under a financing order shall be nonbypassable and paid by all existing and future retail customers receiving transmission or distribution service, or both, from the public utility or its successors or assignees under Commission-approved rate schedules or under special contracts, even if a customer elects to purchase electricity from an alternative electric supplier following a fundamental change in regulation of public utilities in this State.
6. A formula-based true-up mechanism for making, at least annually, expeditious periodic adjustments in the energy transition charges that customers are required to pay pursuant to the financing order and for making any adjustments that are necessary to correct for any overcollection or undercollection of the charges or to otherwise ensure the timely payment of energy transition bonds and financing costs and other required amounts and charges payable in connection with the energy transition bonds.
7. The energy transition property that is, or shall be, created in favor of a public utility or its successors or assignees and that shall be used to pay or secure energy transition bonds and all financing costs.
8. The degree of flexibility to be afforded to the public utility in

establishing the terms and conditions of the energy transition bonds, including, but not limited to, repayment schedules, expected interest rates, and other financing costs.

9. How energy transition charges will be allocated among customer classes.

10. A requirement that, after the final terms of an issuance of energy transition bonds have been established and before the issuance of energy transition bonds, the public utility determines the resulting initial energy transition charge in accordance with the financing order and that such initial energy transition charge be final and effective upon the issuance of such energy transition bonds without further Commission action so long as the energy transition charge is consistent with the financing order.

11. A requirement that the applicant public utility, simultaneously with the inception of the collection of energy transition charges, reduce its rates through a reduction in base rates or by a negative rider on customer bills in an amount equal to the revenue requirement associated with the utility assets being financed by energy transition bonds

12. A method of tracing funds collected as energy transition charges, or other proceeds of energy transition property, and determine that such method shall be deemed the method of tracing such funds and determining the identifiable cash proceeds of any energy transition property subject to a financing order under applicable law.

13. Any other conditions not otherwise inconsistent with this section that the Commission determines are appropriate.

c. A financing order issued to a public utility may provide that creation of the public utility's energy transition property is conditioned upon, and simultaneous with, the sale or other transfer of the energy transition property to an assignee and the pledge of the energy transition property to secure energy transition bonds.

d. If the Commission issues a financing order, the public utility shall file with the Commission at least annually a petition or a letter applying the formula-based mechanism and, based on estimates of consumption for each rate class and other mathematical factors, requesting administrative approval to make the applicable adjustments. The review of the filing shall be limited to determining whether there are any mathematical or clerical errors in the application of the formula-based mechanism relating to the appropriate amount of any overcollection or undercollection of energy transition charges and the amount of an adjustment. The adjustments shall ensure the recovery of revenues sufficient to provide for the payment of principal, interest, acquisition, defeasance, financing costs, or redemption premium and other fees, costs, and charges in respect of energy transition bonds approved under the financing order. Within 30 days after receiving a public utility's request pursuant to this paragraph, the Commission shall either approve the request or inform the public utility of any mathematical or clerical errors in its calculation. If the Commission informs the utility of mathematical or clerical errors in its calculation, the utility may correct its error and refile its request. The time frames previously described in this paragraph shall apply to a refiled request.

e. Subsequent to the transfer of energy transition property to an assignee or the issuance of energy transition bonds authorized thereby, whichever is earlier, a financing order is irrevocable and, except for changes made pursuant to the formula-based mechanism authorized in this section, the Commission may not amend, modify, or terminate the financing order by any subsequent action or reduce, impair, postpone, terminate, or otherwise adjust energy transition charges approved in the financing order. After the issuance of a financing order, the public utility retains sole discretion regarding whether to assign, sell, or otherwise transfer energy transition property or to cause energy transition bonds to be issued, including the right to defer or postpone such assignment, sale, transfer, or issuance.

f. Transition assistance funds, if included in the bond issue, may be transferred to a third-party entity designated by the commission to administer transition assistance on behalf of displaced workers and affected communities.

(4) At the request of a public utility, the Commission may commence a proceeding and issue a subsequent financing order that provides for refinancing, retiring, or refunding the energy transition bonds issued pursuant to the original financing order if the Commission finds that the subsequent financing order satisfies all of the criteria specified in this section for a financing order. Effective upon retirement of the refunded energy transition bonds and the issuance of new energy transition bonds, the Commission shall adjust the related energy transition charges accordingly.

(5) Within 60 days after the Commission issues a financing order or a decision denying a request for reconsideration or, if the request for reconsideration is granted, within 30 days after the Commission issues its decision on reconsideration, an adversely affected party may petition for judicial review in the Supreme Court of North Carolina. Review on appeal shall be based solely on the record before the Commission and briefs to the court and is limited to determining whether the financing order, or the order on reconsideration, conforms to the State Constitution and State and federal law and is within the authority of the Commission under this section.

(6) Duration of financing order. –

a. A financing order remains in effect and energy transition property under the financing order continues to exist until energy transition bonds issued pursuant to the financing order have been paid in full or defeased and, in each case, all Commission-approved financing costs of such energy transition bonds have been recovered in full.

b. A financing order issued to a public utility remains in effect and unabated notwithstanding the reorganization, bankruptcy or other insolvency proceedings, merger, or sale of the public utility or its successors or assignees.

(c) Exceptions to Commission Jurisdiction. –

(1) The Commission may not, in exercising its powers and carrying out its duties regarding any matter within its authority pursuant to this Chapter, consider the energy transition bonds issued pursuant to a financing order to be the debt of the public utility other than for federal income tax purposes, consider the energy transition charges paid under the financing order to be the revenue of the public utility for any purpose, or consider the energy transition costs or financing costs specified in the financing order to be the costs of the public utility, nor may the Commission determine any action taken by a public utility which is consistent with the financing order to be unjust or unreasonable.

(2) The Commission may not order or otherwise directly or indirectly require a public utility to use energy transition bonds to finance any project, addition, plant, facility, extension, capital improvement, equipment, or any other expenditure. After the issuance of a financing order, the public utility retains sole discretion regarding whether to cause the energy transition bonds to be issued, including the right to defer or postpone such sale, assignment, transfer, or issuance. Nothing shall prevent the public utility from abandoning the issuance of energy transition bonds under the financing order by filing with the Commission a statement of abandonment and the reasons therefor. The Commission may not refuse to allow a public utility to recover energy transition costs in an otherwise permissible fashion, or refuse or condition authorization or approval of the issuance and sale by a public utility of securities or the assumption by the public utility of liabilities or obligations, solely because of the potential availability of energy transition bond financing.

(d) Public Utility Duties. –

(1) The electric bills of a public utility that has obtained a financing order and caused energy transition bonds to be issued must comply with the provisions of this subsection; however, the failure of a public utility to comply with this subsection does not invalidate, impair, or affect any financing order, energy transition property, energy transition charge, or energy transition bonds. The public utility must do the following:

a. Explicitly reflect that a portion of the charges on such bill represents energy transition charges approved in a financing order issued to the public utility and, if the energy transition property has been transferred to an assignee, must include a statement to the effect that the assignee is the owner of the rights to energy transition charges and that the public utility or other entity, if applicable, is acting as a collection agent or servicer for the assignee. The tariff applicable to customers must indicate the energy transition charge and the ownership of the charge.

b. Include the energy transition charge on each customer's bill as a separate line item and include both the rate and the amount of the charge on each bill.

c. If a public utility's petition for a financing order is denied or withdrawn or for any reason no energy transition bonds are issued, any costs of retaining expert consultants and counsel on behalf of the commission or the public staff, as authorized by Section  and approved by the commission, shall be paid by the applicant public utility and shall be eligible for recovery by the public utility, including carrying costs, in the electric utility's future rates.

(e) Energy transition Property. –

(1) Provisions applicable to energy transition property. –

a. All energy transition property that is specified in a financing order constitutes an existing, present intangible property right or interest therein, notwithstanding that the imposition and collection of energy transition charges depends on the public utility, to which the financing order is issued, performing its servicing functions relating to the collection of energy transition charges and on future electricity consumption. The property exists (i) regardless of whether or not the revenues or proceeds arising from the property have been billed, have accrued, or have been collected and (ii) notwithstanding the fact that the value or amount of the property is dependent on the future provision of service to customers by the public utility or its successors or assignees and the future consumption of electricity by customers.

b. Energy transition property specified in a financing order exists until energy transition bonds issued pursuant to the financing order are paid in full and all financing costs and other costs of such energy transition bonds have been recovered in full.

c. All or any portion of energy transition property specified in a financing order issued to a public utility may be transferred, sold, conveyed, or assigned to a successor or assignee that is wholly owned, directly or indirectly, by the public utility and created for the limited purpose of acquiring, owning, or administering energy transition property or issuing energy transition bonds under the financing order. All or any portion of energy transition property may be pledged to secure energy transition bonds issued pursuant to the financing order, amounts payable to financing parties and to counterparties under any ancillary agreements, and other financing costs. Any transfer, sale, conveyance, assignment, grant of a security interest in or pledge of energy transition property by a public utility, or an affiliate of the public utility, to an assignee, to the extent previously authorized in a financing order, does not require the prior consent and approval of the Commission.

d. If a public utility defaults on any required payment of charges arising from energy transition property specified in a financing order, a court, upon application by an interested party, and without limiting any other remedies available to the applying party, shall order the sequestration and payment of the revenues arising from the energy transition property to the financing parties or their assignees. Any such financing order remains in full force and effect notwithstanding any reorganization, bankruptcy, or other insolvency proceedings with respect to the public utility or its successors or assignees.

e. The interest of a transferee, purchaser, acquirer, assignee, or pledgee in energy transition property specified in a financing order issued to a public utility, and in the revenue and collections arising from that property, is not subject to setoff, counterclaim, surcharge, or defense by the public utility or any other person or in connection with the reorganization, bankruptcy, or other insolvency of the public utility or any other entity.

f. Any successor to a public utility, whether pursuant to any reorganization, bankruptcy, or other insolvency proceeding or whether pursuant to any merger or acquisition, sale, or other business combination, or transfer by operation of law, as a result of public utility restructuring or otherwise, must perform and satisfy all obligations of, and have the same rights under a financing order as, the public utility under the financing order in the same manner and to the same extent as the public utility, including collecting and paying to the person entitled to receive the revenues, collections, payments, or proceeds of the energy transition property. Nothing in this sub-subdivision is intended to limit or impair any authority of the Commission concerning the transfer or succession of interests of public utilities.

g. Energy transition bonds shall be nonrecourse to the credit or any assets of the public utility other than the energy transition property as specified in the financing order and any rights under any ancillary agreement.

(2) Provisions applicable to security interests. –

a. The creation, perfection, and enforcement of any security interest in energy transition property to secure the repayment of the principal and interest and other amounts payable in respect of energy transition bonds; amounts payable under any ancillary agreement and other financing costs are governed by this subsection and not by the provisions of the Code.

b. A security interest in energy transition property is created, valid, and binding and perfected at the later of the time: (i) the financing order is issued, (ii) a security agreement is executed and delivered by the debtor granting such security interest, (iii) the debtor has rights in such energy transition property or the power to transfer rights in such energy transition property, or (iv) value is received for the energy transition property. The description of energy transition property in a security agreement is sufficient if the description refers to this section and the financing order creating the energy transition property.

c. A security interest shall attach without any physical delivery of collateral or other act, and, upon the filing of a financing statement with the office of the Secretary of State, the lien of the security interest shall be valid, binding, and perfected against all parties having claims of any kind in tort, contract, or otherwise against the person granting the security interest, regardless of whether the parties have notice of the lien. Also upon this filing, a transfer of an interest in the energy transition property shall be perfected against all parties having claims of any kind, including any judicial lien or other lien creditors or any claims of the seller or creditors of the seller, and shall have priority over all competing claims other than any prior security interest, ownership interest, or assignment in the property previously perfected in accordance with this section.

d. The Secretary of State shall maintain any financing statement filed to perfect any security interest under this section in the same manner that the Secretary maintains financing statements filed by transmitting utilities under the Code. The filing of a financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Code.

e. The priority of a security interest in energy transition property is not affected by the commingling of energy transition charges with other amounts. Any pledgee or secured party shall have a perfected security interest in the amount of all energy transition charges that are deposited in any cash or deposit account of the qualifying utility in which energy transition charges have been commingled with other funds and any other security interest that may apply to those funds shall be terminated when they are transferred to a segregated account for the assignee or a financing party.

f. No application of the formula-based adjustment mechanism as provided in this section will affect the validity, perfection, or priority of a security interest in or transfer of energy transition property.

g. If a default or termination occurs under the energy transition bonds, the financing parties or their representatives may foreclose on or otherwise enforce their lien and security interest in any energy transition property as if they were secured parties with a perfected and prior lien under the Code, and the Commission may order amounts arising from energy transition charges be transferred to a separate account for the financing parties' benefit, to which their lien and security interest shall apply. On application by or on behalf of the financing parties, the Superior Court of Wake County shall order the sequestration and payment to them of revenues arising from the energy transition charges.

(3) Provisions applicable to the sale, assignment, or transfer of energy transition property. –

a. Any sale, assignment, or other transfer of energy transition property shall be an absolute transfer and true sale of, and not a pledge of or secured transaction relating to, the seller's right, title, and interest in, to, and under the energy transition property if the documents governing the transaction expressly state that the transaction is a sale or other absolute transfer other than for federal and State income tax purposes. For all purposes other than federal and State income tax purposes, the parties' characterization of a transaction as a sale of an interest in energy transition property shall be conclusive that the transaction is a true sale and that ownership has passed to the party characterized as the purchaser, regardless of whether the purchaser has possession of any documents evidencing or pertaining to the interest. A transfer of an interest in energy transition property may be created only when all of the following have occurred: (i) the financing order creating the energy transition property has become effective, (ii) the documents evidencing the transfer of energy transition property have been executed by the assignor and delivered to the assignee, and (iii) value is received for the energy transition property. After such a transaction, the energy transition property is not subject to any claims of the transferor or the transferor's creditors, other than creditors holding a prior security interest in the energy transition property perfected in accordance with subdivision (2) of subsection (e) of this section.

b. The characterization of the sale, assignment, or other transfer as an absolute transfer and true sale and the corresponding characterization of the property interest of the purchaser, shall not be affected or impaired by the occurrence of any of the following factors:

1. Commingling of energy transition charges with other amounts.
2. The retention by the seller of (i) a partial or residual interest, including an equity interest, in the energy transition property, whether direct or indirect, or whether subordinate or otherwise, or (ii) the right to recover costs associated with taxes, franchise fees, or license fees imposed on the collection of energy transition charges.
3. Any recourse that the purchaser may have against the seller.
4. Any indemnification rights, obligations, or repurchase rights made or provided by the seller.
5. The obligation of the seller to collect energy transition charges on behalf of an assignee.
6. The transferor acting as the servicer of the energy transition charges or the existence of any contract that authorizes or requires the public utility, to the extent that any interest in energy transition property is sold or assigned, to contract with the assignee or any financing party that it will continue to operate its system to provide service to its customers, will collect amounts in respect of the energy transition charges for the benefit and account of such assignee or financing party, and will account for and remit such amounts to or for the account of such assignee or financing party.
7. The treatment of the sale, conveyance, assignment, or other transfer for tax, financial reporting, or other purposes.
8. The granting or providing to bondholders a preferred right to the energy transition property or credit enhancement by the public utility or its affiliates with respect to such energy transition bonds.
9. Any application of the formula-based adjustment mechanism as provided in this section.

c. Any right that a public utility has in the energy transition property before its pledge, sale, or transfer or any other right created under this section or created in the financing order and assignable under this section or assignable pursuant to a financing order is property in the form of a contract right or a chose in action. Transfer of an interest in energy transition property to an assignee is enforceable only upon the later of

(i) the issuance of a financing order, (ii) the assignor having rights in such energy transition property or the power to transfer rights in such energy transition property to an assignee, (iii) the execution and delivery by the assignor of transfer documents in connection with the issuance of energy transition bonds, and (iv) the receipt of value for the energy transition property. An enforceable transfer of an interest in energy transition property to an assignee is perfected against all third parties, including subsequent judicial or other lien creditors, when a notice of that transfer has been given by the filing of a financing statement in accordance with sub-subdivision c. of subdivision (2) of this subsection. The transfer is perfected against third parties as of the date of filing.

d. The Secretary of State shall maintain any financing statement filed to perfect any sale, assignment, or transfer of energy transition property under this section in the same manner that the Secretary maintains financing statements filed by transmitting utilities under the Code. The filing of any financing statement under this section shall be governed by the provisions regarding the filing of financing statements in the Code. The filing of such a financing statement is the only method of perfecting a transfer of energy transition property.

e. The priority of a transfer perfected under this section is not impaired by any later modification of the financing order or energy transition property or by the commingling of funds arising from energy transition property with other funds. Any other security interest that may apply to those funds, other than a security interest perfected under subdivision (2) of this subsection, is terminated when they are transferred to a segregated account for the assignee or a financing party. If energy transition property has been transferred to an assignee or financing party, any proceeds of that property must be held in trust for the assignee or financing party.

f. The priority of the conflicting interests of assignees in the same interest or rights in any energy transition property is determined as follows:

1. Conflicting perfected interests or rights of assignees rank according to priority in time of perfection. Priority dates from the time a filing covering the transfer is made in accordance with sub-subdivision c. of subdivision (2) of this subsection.
2. A perfected interest or right of an assignee has priority over a conflicting unperfected interest or right of an assignee.
3. A perfected interest or right of an assignee has priority over a person who becomes a lien creditor after the perfection of such assignee's interest or right.

(f) Description or Indication of Property. – The description of energy transition property being transferred to an assignee in any sale agreement, purchase agreement, or other transfer agreement, granted or pledged to a pledgee in any security agreement, pledge agreement, or other security document, or indicated in any financing statement is only sufficient if such description or indication refers to the financing order that created the energy transition property and states that the agreement or financing statement covers all or part of the property described in the financing order. This section applies to all purported transfers of, and all purported grants or liens or security interests in, energy transition property, regardless of whether the related sale agreement, purchase agreement, other transfer agreement, security agreement, pledge agreement, or other security document was entered into, or any financing statement was filed.

(g) Financing Statements. – All financing statements referenced in this section are subject to Part 5 of Article 9 of the Code, except that the requirement as to continuation statements does not apply.

(h) Choice of Law. – The law governing the validity, enforceability, attachment, perfection, priority, and exercise of remedies with respect to the transfer of an interest or right or the pledge or creation of a security interest in any energy transition property shall be the laws of this State.

(i) Energy transition Bonds Not Public Debt. – Neither the State nor its political subdivisions are liable on any energy transition bonds, and the bonds are not a debt or a general obligation of the State or any of its political subdivisions, agencies, or instrumentalities, nor are they special obligations or indebtedness of the State or any agency or political subdivision. An issue of energy transition bonds does not, directly, indirectly, or contingently, obligate the State or any agency, political subdivision, or instrumentality of the State to levy any tax or make any appropriation for payment of the energy transition bonds, other than in their capacity as consumers of electricity. All energy transition bonds must contain on the face thereof a statement to the following effect: "Neither the full faith and credit nor the taxing power of the State of North Carolina is pledged to the payment of the principal of, or interest on, this bond."

(j) Legal Investment. – All of the following entities may legally invest any sinking funds, moneys, or other funds in energy transition bonds:

(1) Subject to applicable statutory restrictions on State or local investment authority, the State, units of local government, political subdivisions, public bodies, and public officers, except for members of the Commission.

(2) Banks and bankers, savings and loan associations, credit unions, trust companies, savings banks and institutions, investment companies, insurance companies, insurance associations, and other persons carrying on a banking or insurance business.

(3) Personal representatives, guardians, trustees, and other fiduciaries.

(4) All other persons authorized to invest in bonds or other obligations of a similar nature.

(k) Obligation of Nonimpairment. –

(1) The State and its agencies, including the Commission, pledge and agree with bondholders, the owners of the energy transition property, and other financing parties that the State and its agencies will not take any action listed in this subdivision. This paragraph does not preclude limitation or alteration if full compensation is made by law for the full protection of the energy transition charges collected pursuant to a financing order and of the bondholders and any assignee or financing party entering into a contract with the public utility. The prohibited actions are as follows:

a. Alter the provisions of this section, which authorize the Commission to create an irrevocable contract right or chose in action by the issuance of a financing order, to create energy transition property, and make the energy transition charges imposed by a financing order irrevocable, binding, or nonbypassable charges.

b. Take or permit any action that impairs or would impair the value of energy transition property or the security for the energy transition bonds or revises the energy transition costs for which recovery is authorized.

c. In any way impair the rights and remedies of the bondholders, assignees, and other financing parties.

d. Except for changes made pursuant to the formula-based adjustment mechanism authorized under this section, reduce, alter, or impair energy transition charges that are to be imposed, billed, charged, collected, and remitted for the benefit of the bondholders, any assignee, and any other financing parties until any and all principal, interest, premium, financing costs and other fees, expenses, or charges incurred, and any contracts to be performed, in connection with the related energy transition bonds have been paid and performed in full.

(2) Any person or entity that issues energy transition bonds may include the language specified in this subsection in the energy transition bonds and related documentation.

(l) Not a Public Utility. – An assignee or financing party is not a public utility or person providing electric service by virtue of engaging in the transactions described in this section.

(m) Conflicts. – If there is a conflict between this section and any other law regarding the attachment, assignment, or perfection, or the effect of perfection, or priority of, assignment or transfer of, or security interest in energy transition property, this section shall govern.

(n) Consultation. – In making determinations under this section, the Commission or public staff or both may engage an outside consultant and counsel.

(o) Effect of Invalidity. – If anyprovision of this section is held invalid or is invalidated, superseded, replaced, repealed, or expires for any reason, that occurrence does not affect the validity of any action allowed under this section which is taken by a public utility, an assignee, a financing party, a collection agent, or a party to an ancillary agreement; and any such action remains in full force and effect with respect to all energy transition bonds issued or authorized in a financing order issued under this section before the date that such provision is held invalid or is invalidated, superseded, replaced, or repealed, or expires for any reason."

(p) **Conditions for selecting replacement capacity and energy [DISCLAIMER: This section received support by the majority, but not by all NERP participants.]**

(1) the public utility shall employ a competitive bidding process, approved by the commission as to its structure, to procure energy resources required to fill the resource need resulting from the closure of generating facilities under this Section.

(2) The Commission may permit the utility or its affiliates to compete in the bidding process and own a portion of the replacement resources, including associated infrastructure, if the Commission finds –

a. The utility bids were evaluated in the same manner as other bids;
b. the cost of utility or affiliate ownership of the replacement resources is reasonable and is the least cost choice, with an acceptable rate impact; and
c. that utility ownership of replacement resources is necessary to assure the utility's financial health.

(3) Utility ownership may consist of utility or affiliate self-builds, build-transfers from independent power producers, or sales of existing assets from independent power producers or similar commercial arrangements.

(4) In determining whether to approve proposed replacement resources, the Commission shall consider –

a. the risk that future federal environmental regulations could increase the life-cycle cost of the resource and create future stranded assets; and
b. whether the proposed replacement resources support the state's energy goals, as expressed by the governor and the legislature.

**SECTION 2.** G.S. 25-9-109(d) reads as rewritten:

"(d) Inapplicability of Article. – This Article does not apply to:

…

(13) An assignment of a deposit account in a consumer transaction, but G.S. 25-9-315 and G.S. 25-9-322 apply with respect to proceeds and priorities in proceeds; ~~or~~

(14) The creation, perfection, priority, or enforcement of any lien on, assignment of, pledge of, or security in, any revenues, rights, funds, or other tangible or intangible assets created, made, or granted by this State or a governmental unit in this State, including the assignment of rights as secured party in security interests granted by any party subject to the provisions of this Article to this State or a governmental unit in this State, to secure, directly or indirectly, any bond, note, other evidence of indebtedness, or other payment obligations for borrowed money issued by, or in connection with, installment or lease purchase financings by, this State or a governmental unit in this State. However, notwithstanding this subdivision, this Article does apply to the creation, perfection, priority, and enforcement of security interests created by this State or a governmental unit in this State in equipment or fixtures; ~~or~~

(15) The creation, perfection, priority, or enforcement of any sale, assignment of, pledge of, security interest in, or other transfer of, any interest or right or portion of any interest or right in any storm recovery property as defined G.S. 62-172;
"or

(16) The creation, perfection, priority, or enforcement of any sale, assignment of, pledge of, security interest in, or other transfer of, any interest or right or portion of any interest or right in any energy transition property as defined G.S. 62-173."

**SECTION 3.** This act is effective when it becomes law.