PJM Cost of New Entry

Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date

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Executive Summary

PJM Interconnection, L.L.C (PJM) retained 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.[1] This report presents our estimates of the Cost of New Entry (CONE). A separate, concurrently-released report presents our review of PJM's methodology for estimating the net energy and ancillary service (E&AS) revenue offset and the Variable Resource Requirement (VRR) curve.[2]

CONE represents the total annual net revenue (net of variable operating costs) that a new generation resource would need to recover its capital investment and fixed costs, given reasonable expectations about future cost recovery over its economic life. CONE is the starting point for estimating the Net Cost of New Entry (Net CONE). Net CONE represents the first-year revenues that a new resource would need to earn in the capacity market, after netting out E&AS margins from CONE. CONE and Net CONE of the simple-cycle combustion turbine (CT) reference resource are used to set the prices on PJM's VRR curve.[3] CT and combined-cycle (CC) Net CONE are used to establish offer price thresholds below which new gas-fired generation offers are reviewed under the Minimum Offer Price Rule (MOPR).[4]

We estimate CONE for CTs and CCs in each of the four CONE Areas specified in the PJM Tariff, with an assumed online date of June 1, 2022.[5] Our estimates are based on complete plant designs reflecting the locations, technology choices, and plant configurations that developers are likely to choose, as indicated by actual projects and current environmental requirements. For both the CT and CC plants, we specify GE 7HA turbines—one for the CT, and two for the CC in combination with a single heat recovery steam generator and steam turbine ("2×1 configuration"). Most plants have selective catalytic reduction (SCR), except CTs in the Rest of RTO Area. Most plants also have dual-fuel capability, except CCs in the SWMAAC Area, which obtain firm gas transportation service instead.

For each plant type and location, we conduct 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

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1 PJM Interconnection, L.L.C. (2017). PJM Open Access Transmission Tariff. Effective October 1, 2017, ("PJM 2017 OATT"), accessed 2/7/2018 from http://www.pjm.com/directory/merged-tariffs/oatt.pdf, Section 5.10 a.

2 "Fourth Quadrennial Review of PJM's Variable Resource Requirement Curve" or "2018 VRR Report".

3 See 2018 VRR Report for how CONE and Net CONE values are used to set the VRR curve.

4 PJM 2017 OATT, Section 5.14 h.

5 Previous CONE studies had five CONE Areas, but the Dominion CONE Area was removed in recent tariff changes and is now included in the Rest of RTO CONE Area.

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.

Finally, we translate the estimated costs into the annualized average net revenues the resource owner would have to earn over an assumed 20-year economic life to achieve its required return on and return of capital. We assume an after-tax weighted-average cost of capital (ATWACC) of 7.5% for a merchant generation investment, which we estimated based on various reference points. An ATWACC of 7.5% is equivalent to a return on equity of 12.8%, a 6.5% cost of debt, and a 65/35 debt-to-equity capital structure with an effective combined state and federal tax rate of 29.25%. For some states with higher state income tax rates of 10%, the ATWACC is 7.4%. We adopt the "level-nominal" approach for calculating the first-year annualized costs of the plants.

Table ES-1 below shows the updated 2022/23 CONE estimates and how the values compare to the CONE parameters used in the upcoming auctions for the 2021/22 delivery year, escalated forward one year to 2022/23. As indicated, costs have decreased sharply by 22–28% for CTs and 40–41% for CCs.

Table ES-1: Updated 2022/2023 CONE Values

	Simple Cycle ($/ICAP MW-year)				Combined Cycle ($/ICAP MW-year)			
	EMAAC	SWMAAC	Rest of RTO	WMAAC	EMAAC	SWMAAC	Rest of RTO	WMAAC
2021/22 Auction Parameter	$133,144	$140,953	$133,016	$134,124	$186,807	$193,562	$178,958	$185,418
...Escalated to 2022/23	$136,900	$144,900	$136,700	$137,900	$192,000	$199,000	$184,000	$190,600
Updated 2022/23 CONE	**$106,400**	**$108,400**	**$98,200**	**$103,800**	**$116,000**	**$120,200**	**$109,800**	**$111,800**
Difference from Prior CONE	-22%	-25%	-28%	-25%	-40%	-40%	-40%	-41%

Sources and notes:

All monetary values are presented in nominal dollars.

2021/22 auction parameter values based on Minimum Offer Price Rule (MOPR) Floor Offer Prices for 2021/22 BRA.

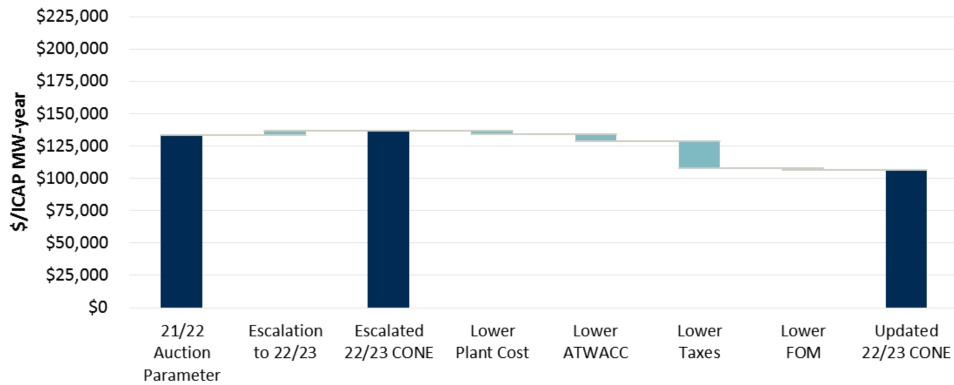
PJM 2021/22 parameters escalated to 2022/23 by 2.8%, based on S&L analysis of escalation rates for materials, turbine, and labor costs.

CONE includes major maintenance costs in variable O&M costs. Alternative values with major maintenance costs in fixed O&M costs are presented in Appendix C.

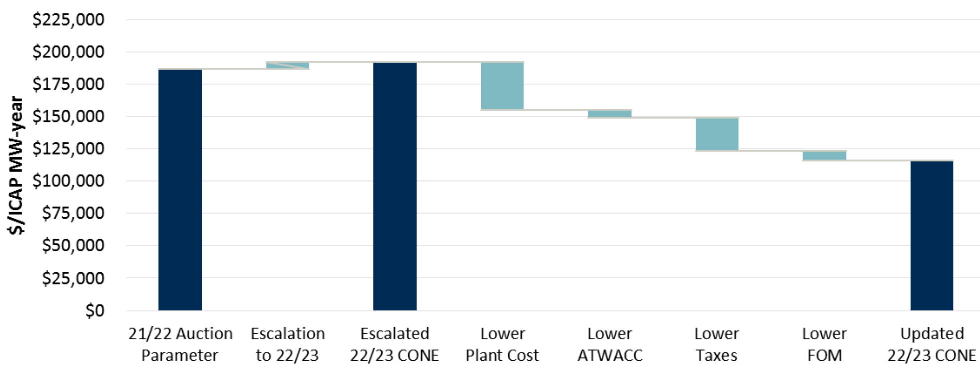
The drivers of these decreases are shown in Figure ES-1 and explained below.

Figure ES-1: Drivers of Lower CT and CC 2022/2023 CONE Estimates (EMAAC)

(a) Simple Cycle Combustion Turbine (CT)



(b) Combined Cycle (CC)



Notes:
"FOM" stands for fixed O&M costs.
CONE includes major maintenance in variable O&M costs.

Three factors drive most of this decrease in CONE:

- **Economies of scale on larger combustion turbines.** Selection of GE 7HA.02 turbines instead of the 7FA.05 turbines used in the 2014 PJM CONE study reflects a recent trend in actual project developments and future orders toward larger turbines. The GE H-class turbines are sized at 320 MW per turbine compared to 190 MW for F-class turbines in 2014; the capacity of a 2×1 CC plant nearly doubles from 650 to 1,140 MW.[6] This lowers both construction labor and equipment costs on a per-kW basis. As a result, the current overnight capital costs for a CT are only $799/kW to $898/kW (depending on location), 2–10% lower than the 2014 estimates of $890/kW to $927/kW escalated forward to 2022.[7]

6 The max summer capacity is based on the estimated values for the Rest of RTO CONE Area.

7 We compare the current capital cost estimates to those filed by PJM in the 2014 CONE update. We escalated the 2018 capital costs to 2022 by first applying the location-specific escalation rates PJM used for the 2019/20, 2020/21, and 2021/22 CONE updates for the first three years and then escalating the costs an additional year by 2.8%/year based on cost trends in labor, equipment, and materials inputs.

CC capital costs range from $772/kW to $873/kW, about 25% lower than the 2014 estimates of $1,054/kW to $1,127/kW escalated to 2022.

- **Reduced federal taxes.** The tax law passed in December 2017 reduced the corporate tax rate to 21% and temporarily increased bonus depreciation to 100%, although it eliminated the state income tax deduction.[8] These changes decrease the CT CONE by about $21,000/MW-year (17% lower) and the CC CONE by about $25,000/MW-year (18% lower), before accounting for the higher cost of capital due to the lower tax rate.
- **Lower cost of capital.** We estimate an ATWACC of 7.5% for merchant generation based on current and projected capital market conditions and the change in the corporate tax rate. Compared to an ATWACC of 8.0% in the 2014 study, the lower ATWACC reduces the annual CONE value by 3.7% for CTs and 3.8% CCs.

The updated CONE values shown above assume that major maintenance costs are treated as variable O&M costs, as in past CONE studies. We separately report in Appendix C alternative CONE values to reflect changes in the PJM cost guidelines since the 2014 CONE Study in which major maintenance costs are classified as fixed O&M costs instead of variable O&M costs.[9] Classifying these costs as fixed instead of variable increases CONE by $19,000/MW-year for CTs (a 19% increase) and $10,000/MW-year for CCs (a 9% increase). However, removing these costs from variable O&M increases Net E&AS revenues and offsets the increased CONE value in the calculation of Net CONE.

Table ES-2 shows additional details on the CONE estimates for CT plants in each CONE Area. The higher CONE in SWMAAC relative to other areas reflects higher property taxes in Maryland that are based on all property, including equipment, not just land and buildings. EMAAC's relatively high costs reflect higher labor costs there. The Rest of RTO Area has the lowest CONE value due to lower labor costs and the assumption that an SCR is not needed to reduce NOx emissions in attainment areas.

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8 "Bonus depreciation" refers to the allowance by tax law of highly accelerated tax depreciation immediately upon in-service of a depreciable asset. In recent years, bonus depreciation has been enabled by legislation in varying percentages of the overall tax basis in an asset, with the remainder deducted over the asset life as otherwise allowed. Per the 2017 tax law, bonus depreciation is allowed for companies not classified as public utilities up to 100% of tax basis.

9 An ongoing stakeholder process within the Markets Implementation Committee is addressing whether the PJM cost guidelines should be modified to again allow major maintenance costs to be included in variable O&M costs.

Table ES-2: Estimated CT CONE for 2022/2023

		Simple Cycle			
		EMAAC	SWMAAC	Rest of RTO	WMAAC
Net Summer ICAP	*MW*	352	355	321	344
Overnight Costs	*$/kW*	$898	$836	$799	$886
Effective Charge Rate	*%*	10.1%	10.1%	10.0%	10.0%
Plant Costs	*$/MW-yr*	$90,300	$84,300	$80,300	$88,900
Fixed O&M	*$/MW-yr*	$16,100	$24,100	$17,900	$14,900
Levelized CONE	***$/MW-yr***	**$106,400**	**$108,400**	**$98,200**	**$103,800**
Levelized CONE	***$/MW-day***	**$292**	**$297**	**$269**	**$284**

Notes: CONE values expressed in 2022 dollars and Installed Capacity (ICAP) terms.

Table ES-3 shows the recommended CONE estimates for CC plants in each CONE Area. SWMAAC has the highest CONE estimate due to higher property taxes and the higher costs of firm gas transportation service compared to dual-fuel capabilities (which is specified in the other Areas). EMAAC has the next highest CONE estimate due to higher labor costs than the rest of PJM. WMAAC and Rest of RTO have the lowest CC CONE estimates due to the lower labor costs in those areas.

Table ES-3: Estimated CC CONE for 2022/2023

		Combined Cycle			
		EMAAC	SWMAAC	Rest of RTO	WMAAC
Net Summer ICAP	*MW*	1,152	1,160	1,138	1,126
Overnight Costs	*$/kW*	$873	$772	$815	$853
Effective Charge Rate	*%*	10.6%	10.6%	10.5%	10.5%
Plant Costs	*$/MW-yr*	$92,200	$81,800	$85,900	$89,900
Fixed O&M	*$/MW-yr*	$23,800	$38,400	$23,900	$21,900
Levelized CONE	***$/MW-yr***	**$116,000**	**$120,200**	**$109,800**	**$111,800**
Levelized CONE	***$/MW-day***	**$318**	**$329**	**$301**	**$306**

Notes: CONE values expressed in 2022 dollars and ICAP terms.

The updated CONE estimates for CCs have decreased significantly more than CTs over the prior estimates, leading to a CC premium of $8,000–11,800/MW-year compared to $46,000–54,000/MW-year in the 2020/21 Base Residual Auction (BRA) parameters. The most significant driver narrowing the difference between CT and CC CONE is economies of scale of the larger CC based on the 7HA. While the capacity of the CCs plants has almost *doubled* compared to that in the 2014 CONE Study, the cost of the gas turbines increased by 50%, and the cost of the steam section of the CC (including the heat recovery steam generator and steam turbine) increased by only 30%. CT plants share the same economies of scale on the combustion turbine itself, but not the greater economies of scale that CCs enjoy on their steam section or other plant costs.

Looking beyond the 2022/23 delivery year, we recommend that PJM update the above CONE estimates prior to each subsequent auction using its existing annual updating approach based on a composite of cost indices, but with slight adjustments to the weightings. Consistent with the updated capital cost estimates, we recommend that PJM weight the components in the CT composite index based on 20% labor, 55% materials (increased from 50%), and 25% turbine (decreased from 30%). We recommend that PJM weight the CC components based on 30% labor (increased from 25%), 50% materials (decreased from 60%), and 20% turbine (increased from 15%). PJM will need to account for bonus depreciation declining by 20% in subsequent years starting in 2023. Consequently, after PJM has escalated CONE by the composite cost index, we recommend that PJM apply an additional gross-up of 1.022 for CT and 1.025 for CCs each year to account for the declining tax advantages as bonus depreciation phases out.

I. Introduction

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." The VRR curve is determined administratively based on a design objective to procure sufficient capacity for maintaining resource adequacy in all locations while mitigating price volatility and susceptibility to market power abuse. As such, the VRR curves are centered approximately on a target point with a price given by the estimated Net Cost of New Entry (Net CONE) and a quantity corresponding to PJM's resource adequacy requirement. The curve's slope mitigates price volatility, and a slight right shift (relative to the target point) avoids low reliability outcomes.

In order for the VRR curve to procure sufficient capacity, the Net CONE parameter must accurately reflect the price at which developers would actually be willing to enter the market. Estimated Net CONE should reflect the first-year capacity revenue an economically-efficient new generation resource would need (in combination with expected energy and ancillary services (E&AS) margins) to recover its capital and fixed costs, given reasonable expectations about future cost recovery under continued equilibrium conditions. PJM estimates Net CONE for a defined "reference resource" by subtracting its estimated one-year E&AS margins from its estimated Cost of New Entry (CONE).

CONE values are determined through quadrennial CONE studies such as this one, with escalation rates applied in the intervening years.[10] PJM separately estimates Net E&AS revenue offsets annually for setting the zone-specific Net CONE values in each auction. Just prior to each three-year forward auction, PJM determines Net CONE values for each of four CONE Areas, which are used to establish VRR curves for the system and for all Locational Deliverability Areas (LDAs).[11]

PJM has traditionally estimated CONE and Net CONE based on a gas-fired simple-cycle combustion turbine (CT) as the reference resource. In addition to anchoring the VRR curve, PJM uses CONE estimates for CT and combined-cycle (CC) plants for calculating offer price screens under the Minimum Offer Price Rule (MOPR) for new generation offering capacity into RPM.[12]

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10 PJM 2017 OATT, Section 5.10 a.

11 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.

12 PJM 2017 OATT, Section 5.14 h.

B. Study Objective and Scope

We were asked to assist PJM and stakeholders in this quadrennial review by developing CONE estimates for new CT and CC plants in each of the four CONE Areas for the 2022/23 Base Residual Auction (BRA) and proposing a process to update these estimates for the following three BRAs.

Our objective in estimating CONE is to reflect the technology, 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 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 tradeoffs and provide our own recommendations for best meeting RPM's objectives to inform PJM's decisions in setting future VRR curves.

We review PJM's methodology for estimating the Net E&AS revenue offsets for each reference resource and the criteria for selecting the reference resource in the parallel 2018 VRR Curve Report.

C. Analytical Approach

Our starting point for estimating CONE is a characterization of the CC and CT plants in each CONE Area to reflect the technologies, plant configurations, detailed specifications, and locations where developers are most likely to build. While the turbine technology and other specifications for the reference resource are detailed in PJM's tariff, we review the most recent gas-fired generation projects in PJM and the U.S. to determine whether these assumptions remain relevant to the PJM market.[13] The key configuration variables we define for each plant include the number of gas and steam turbines, duct firing and power augmentation, cooling systems, emissions controls, and dual-fuel capability.

We identified specific plant 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. We selected key site characteristics, which include proximity to high voltage transmission infrastructure and interstate gas pipelines, siting attractiveness as indicated by units recently built or currently under construction, and availability of vacant industrial land. Our analysis for selecting plant characteristics and locations for each CONE Area is presented in Section III of this report.

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13 PJM 2017 OATT.

We developed comprehensive, bottom-up estimates of the costs of building and maintaining the candidate references resources in each of the four CONE Areas. 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. The results of this analysis are presented in Section IV.

We further estimated annual fixed and variable O&M costs, including labor, materials, property tax, insurance, asset management costs, and working capital. The results of this analysis are presented in Section V.

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. We present our financial assumptions for converting the costs of building and operating the plant into an annualized CONE estimate in Section VI and a summary of the CONE estimates in Section VII.

The Brattle and Sargent & Lundy authors collaborated on completing 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.

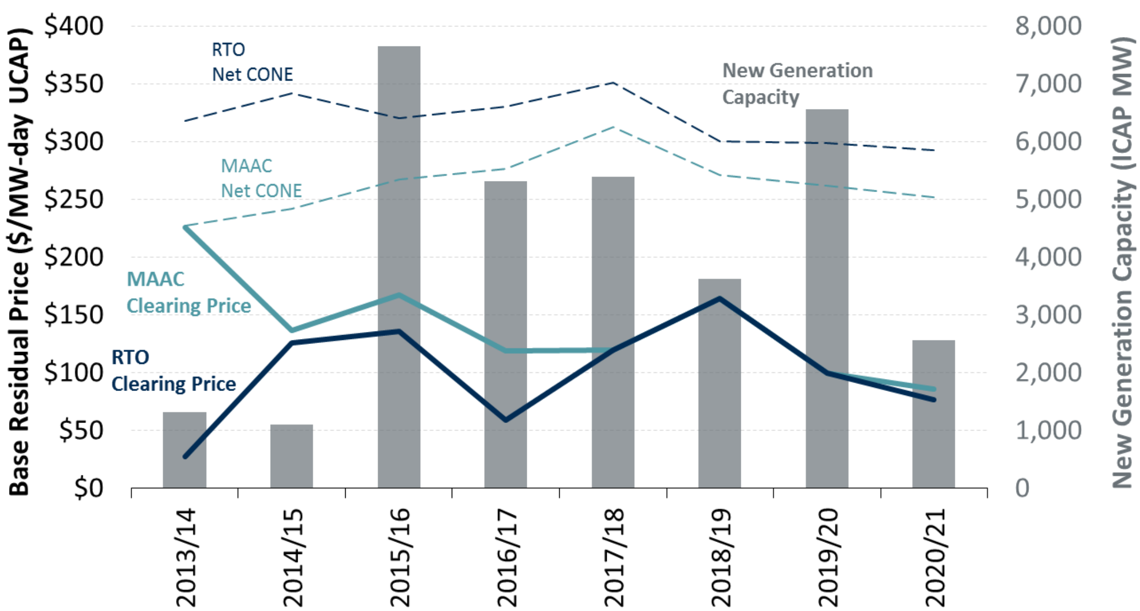
II. Observations about Recent Entry in PJM's Capacity Market

As a starting point for our analysis of the Net Cost of New Entry, we reviewed the recent market activity to better understand the underlying dynamics in the PJM Base Residual Auctions and identify areas of focus for the current Net CONE study.

A. Summary of Recent New Entry in PJM

Over 31,000 ICAP MW of new generation resources cleared the market in the six auctions since the 2015/16 Base Residual Auction (BRA) despite the auctions clearing well below the administratively-determined Net CONE parameter. Figure 1 below shows that, on average, these auctions have cleared at prices 60% below the Net CONE parameter during this period of significant entry of new generation resources.[14] As the clearing prices reflect the offer price of the marginal unit clearing the market, new generation resources must have on average been submitting offers into the auction at even lower prices.

Figure 1: Base Residual Auction Clearing Prices and Cleared New Generation Capacity



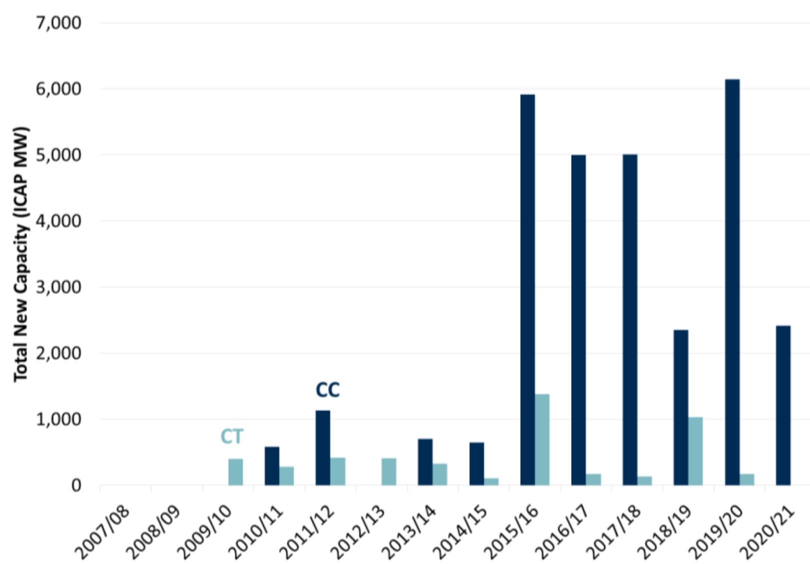
Sources and notes:
PJM Annual Base Residual Auction Results, accessed September 2017, http://www.pjm.com/markets-and-operations/rpm.aspx

[14] Some new generation capacity has cleared in sub-zones at higher prices than shown in Figure 1. However, most of the new capacity that has cleared during this time period did so at the prices shown here.

About half of new generation capacity since the 2015/16 BRA cleared in MAAC and the other half cleared in the rest of the PJM system.[15] A third of the new plants are CCs located close to shale gas production regions in Pennsylvania and Ohio to take advantage of pipeline constraints that result in lower local gas prices relative to the rest of PJM.[16] The remaining plants are located throughout the PJM market with significant additions in Virginia, New Jersey, and the western portions of PJM.

Nearly all new generating units entering the BRAs are natural-gas-fired. Most of these new natural gas plants consist of CC plants, as shown in Figure 2 below, while the Net CONE parameter is currently set based on a CT. There were significant additions of new CTs in PJM prior to 2005, but limited merchant entry since then.[17] While CCs went through a similar lull in new additions between 2005 and 2014—when the PJM capacity market attracted other resource types, such as uprates to existing plants, deferred retirement, imports, and demand response—a total of 27,000 MW of new CC plants have cleared since the 2015/16 BRA.

Figure 2: CC and CT Generation Capacity Cleared in Past BRAs



Sources and notes:
PJM Base Residual Auction Results for 2020/21, published on 5/23/2017.

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15 Based on the PJM Annual Base Residual Auction Results, there has been 12,800 Unforced Capacity (UCAP) MW of new capacity in MAAC since the 2015/16 BRA and 13,000 UCAP MW of new capacity in the rest of the PJM system. PJM Annual Base Residual Auction Results, accessed September 2017, http://www.pjm.com/markets-and-operations/rpm.aspx

16 We identified plants with access to lower-cost natural gas based on the gas hub listed for each plant in ABB Inc.'s *Energy Velocity Suite*. We considered plants with access to gas priced based on the Dominion South, Dominion North, Leidy Hub, Transco Leidy Receipts, or Tennessee Gas Pipeline Zone 4 as within shale production regions.

17 There has been entry of just two merchant CTs since 2014 (340 MW Doswell Peaking Unit and 141 MW Perryman Unit 6).

B. Drivers of Low-Cost Entry by Natural Gas Plants

Several factors have led to the significant investment in new gas-fired CC plants at capacity market prices that have been on average 60% below PJM's Net CONE value during the past six BRAs. Coal and nuclear retirements and the exit of some demand response resources created the need for new entry. We believe that the entry by CC plants was possible at the observed low prices in large part due to improved combustion turbine performance, lower plant cost on a $/kW basis, low-cost investment capital, and low natural gas prices (allowing for large spark spreads) in some locations.

Generation Retirements: There has been a surge of generation retirements in PJM since 2011 with 32,800 MW of existing resourcing deactivating or requesting deactivations over the ten-year period from 2011 to 2020 (compared to just 6,600 MW from 2002 to 2010).[18] The majority of these retirements have been coal plants (26,000 MW) while several nuclear plants (3,200 MW) have announced retirements by 2020.[19] Even during a period of limited load growth, the retirements provided an opportunity for new generation resources to enter the market.[20] The retirements help explain the scale of recent new entry, but not the low prices at which entry has occurred. We next examine several factors that contribute to new gas CCs entering the capacity auctions at prices below the estimated Net CONE.

Turbine Performance: The efficiency and net plant capacity of gas turbines has risen significantly since 2010. As shown in Figure 3 below, CC plants with GE 7FA turbines in a 2×1 configuration (2 gas turbines, 1 steam turbine) have increased their net plant capacity since 2008 by 220 MW (a 42% increase), while reducing their net plant heat rate (HHV) by 440 Btu/kWh from 6,780 to 6,340 Btu/kWh (a 6% decrease).[21] This trend in performance is significant even before accounting for the introduction of the larger, more efficient H-class turbines that are now beginning to enter the market (see Section III.B below). The H-class turbines provide a step change in terms of the economies of scale: a 2×1 CC configuration with H-class turbines achieves a net plant output of about 1,100 MW and a net heat rate (HHV) of nearly 6,100 Btu/kWh.[22] The larger turbines result in significant cost savings on a per-kW basis due to the economies of scale for developing such large plants. The improved efficiency of these turbines increases the Net

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18 PJM. Generator Deactivation Summary Sheets, accessed December 2017, http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx

19 ABB Inc.'s *Energy Velocity Suite* December 2017.

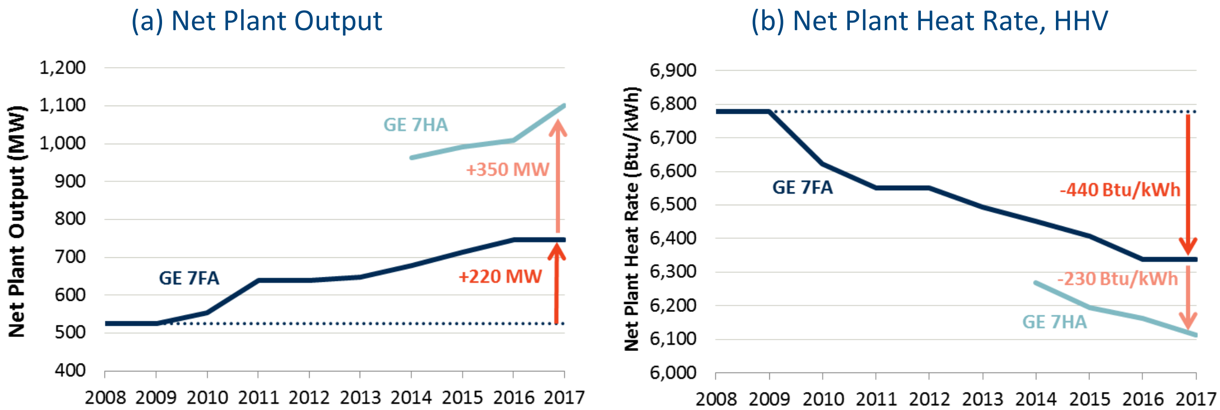
20 The Reliability Requirement (adjusted for FRR) grew by just 6,000 MW (4%) from the 2014/15 BRA (148,323 MW) to the 2020/21 BRA (154,355 MW). Annual BRA parameters available here: http://www.pjm.com/markets-and-operations/rpm.aspx

21 Gas Turbine World, "2016–17 GTW Handbook," Volume 32.

22 The net heat rate reported here is lower than estimated for each CONE Area due to the conditions under which the heat rate is estimated (ISO conditions of 59°F, 60% Relative Humidity and 0 feet above mean sea level).

E&AS revenue offset for the new gas plants by reducing their dispatch costs and increasing the frequency with which they operate. Both trends result in reduced offers into the PJM capacity auctions.

Figure 3: Historical Performance of GE 7FA and GE 7HA in a 2×1 Combined-Cycle Configuration



Sources and notes:
Gas Turbine World, "2016–17 GTW Handbook," Volume 32.

Turbine Costs: The increase in net plant capacity since 2008 for CTs has occurred during a period of relatively limited cost increases for the turbines and the overall plants. The result is a significantly lower cost for gas-fired combustion turbines on a per-kW basis, whether in simple-cycle or combined-cycle configurations. The per-kW costs for combustion turbines have declined by nearly 40% since they peaked in 2010 and by 11% since 2014 (see Section VII.A for a further discussion of these trends). Similarly, the composite index that PJM uses to annually adjust the CT CONE value based on the Department of Commerce's Bureau of Labor Statistics (BLS) indices has decreased by 17% since 2010 when adjusted for the increased capacity of new CTs over this time period.[23] The declining cost for new turbines and plants on a per-kW basis result in a decline in the CONE for new gas plants.

Financing Cost: Financial drivers have contributed to reducing the price at which offers are placed into the PJM capacity auctions. The financing cost (cost of capital) for merchant generators has declined in recent years with the estimated after-tax weighted-average cost of capital (ATWACC) for publicly-traded merchant developers declining from 8.0% in 2014 to the current value of 7.5% as estimated in this study. Additional cost of capital reference points we identified based on analyst reports of recent acquisitions (as explained in detail in Section VI.A below) show the cost of capital may have been even lower in recent years.[24] A reduction in the cost of capital from 8.0% to 7.5% reduces CONE by about 3.8%. In addition, bonus depreciation

23 The composite gas plant index that PJM uses blends BLS indices for turbine cost (30%), material costs (50%), and labor costs (20%). We discuss PJM's approach to annual updates to CONE based on these indices in Section VIII. below.

24 For example, the June 2017 fairness opinion for the Calpine acquisition by Energy Capital Partners assumed 5.75% to 6.25% for Calpine's weighted-average cost of capital.

was available for the most recent new plants at the time of the auctions they cleared—with plants online by the end of 2017 able to depreciate 50% of their costs in the first year, 40% for plants online in 2018, and 30% for plants online in 2019.[25] We estimate that 30% bonus depreciation reduces CONE by about 3.5%.

Natural Gas Prices: The coal and nuclear plant retirements and entry of new gas CCs has been triggered by sustained low prices for natural gas. Shale gas production from the Marcellus and Utica formations that lie within the PJM market footprint increased significantly since 2010, resulting in lower gas prices across PJM and the U.S. as shown in Figure 4.[26] Gas prices in shale production regions, as represented below by the Dominion South hub (light blue line), have sold at a discount of $1–2/MMBtu to Henry Hub since 2014. Lower gas prices have extended to the eastern portions of PJM, as represented by the Transco Zone 6 Non-NY hub (red line), during three of the past four summers as well. Based on traded natural gas futures, Dominion South gas prices are expected to remain on average around $2.50/MMBtu through 2022, nearly $0.50/MMBtu lower than Henry Hub (dark blue line), based on current gas futures.

Figure 4: Gas Prices at Representative Gas Hubs in PJM

Sources and notes:

Historical prices downloaded from ABB Inc.'s *Energy Velocity Suite* and futures prices from SNL in December 2017.

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25 Bonus depreciation was re-introduced as a part of the changes to federal taxes in December 2017, starting at 100% for plants online by January 1, 2023 and then phasing out over the following five years. We discuss the implications of the bonus depreciation for new resources in Section VI.B below.

26 U.S. Energy Information Administration, 2010–2015. "U.S. Shale Gas Production", accessed December 2017 at https://www.eia.gov/dnav/ng/ng_prod_shalegas_s1_a.htm.

Lower gas prices reduce the fuel costs for new gas CCs relative to other fossil-fuel-fired plants that may determine PJM wholesale energy market prices—primarily coal plants—and result in higher annual output from these plants.[27] Lower gas prices will reduce average energy market prices and *net* revenues across all generation resources. Whether lower gas prices result in higher or lower net revenues for the new CCs will depend on the relative heat rate of the new gas plants compared to the market heat rate as set by generating units that tend to be on the margin for most of the year. Plants that enjoy a unique advantage in shale-gas locations are likely to earn higher net revenues as electricity market prices will be set by resources that must pay a higher price for delivered fuel, increasing the spread between revenues and costs for the CCs located in these shale-gas-regions.

We reviewed these recent market trends to understand what is driving the significant development of new gas-fired units at prices well below those projected in previous CONE studies and incorporated these trends into our analysis in the remainder of this report.

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27 Coal has been on the margin in PJM for 45–60% of hours since 2012. PJM, 2012–2016 CO_2, SO_2 and NO_X Emission Rates, March 17, 2017, p. 3. Available at: https://www.pjm.com/~/media/library/reports-notices/special-reports/20170317-2016-emissions-report.ashx

III. Reference Resource Technical Specifications

Similar to the 2014 PJM CONE Study, we determined the characteristics of the reference resources primarily based on a "revealed preferences" approach that relies on our review of the choices that actual developers found to be most feasible and economic. 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 selecting the reference resource location within each CONE Area, we relied on a similar analysis for the 2014 PJM CONE Study that considers a broad view of potential sites that can be considered feasible and favorable for new plant development. For determining most of the reference resource specifications, we updated our analysis from the 2014 study by examining CT and CC plants built in PJM and the U.S. since 2014, including plants currently under construction. We characterized these plants by size, plant configuration, turbine type, duct firing, environmental controls, dual-fuel capability, and cooling system.

A. Locational Screen

The PJM Open Access Transmission Tariff (OATT) requires a separate CONE parameter in each of four CONE Areas as summarized in Table 1.[28]

Table 1: PJM CONE Areas

	CONE Area	Transmission Zone	States
1	**EMAAC**	AECO, DPL, JCPL, PECO, PSEG, RECO	NJ, MD, PA, DE
2	**SWMAAC**	BGE, PEPCO	MD, DC
3	**Rest of RTO**	AEP, APS, ATSI, ComEd, DAY, DEOK, DQL, DOM	WV, VA, NC, OH, IN, IL, KY, TN, MI, PA, MD
4	**WMAAC**	MetEd, Penelec, PPL	PA

We conducted a locational screening analysis to identify feasible and favorable locations for each of the four CONE Areas. Our approach for identifying the representative locations within each CONE Area included three steps:

1. We identified candidate locations based on the revealed preference of actual plants built since 2014 or under construction to identify the areas of primary development, putting more weight on recent projects.

2. We sharpened the definition of likely areas for future development, depending on the extent of information available from the first step. For CONE Areas where recent

[28] PJM 2017 OATT, Section 5.10 a.

projects provide a clear signal of favored locations, we excluded only counties that would appear to be less attractive going forward, based on environmental constraints or economic costs (absent special offsetting factors we would not know about). For CONE Areas where the revealed preference data is weak or scattered, we identified promising locations from a developer perspective based on proximity to gas and electric interconnections and key economic factors such as labor rates and energy prices.

3. This approach results in identifying a specified area that spans several counties. For this reason, we developed cost estimates for each CONE Area by taking the average of cost inputs (*e.g.*, labor rates) across the specified locations.

The locations chosen for each CONE Area are shown in Figure 5. To provide a more detailed description of the specified locations, we show in Table 2 the cities used for estimating labor rates.

Our review of recent development in CONE Area 1 **Eastern MAAC (EMAAC)** resulted in identifying southern New Jersey and portions of northern Delaware, northeast Maryland, and southeast Pennsylvania as the reference resource location. We identified significant development in this region and northern New Jersey. Northern New Jersey projects are either located on brownfield sites or at existing sites, which are not widely available to future developers. Moreover, recent developments were more heavily concentrated in the southern portion of EMAAC. The economics are more favorable in this area with lower labor costs and higher energy market prices.

In CONE Area 2 **Southwest MAAC (SWMAAC)**, we maintained the same location as the 2014 CONE Study in southern Maryland, including portions of Charles, Prince George's, and Anne Arundel counties. There have been two new CC units developed in this region recently compared to a single CT in northern Maryland.

For the larger CONE Area 3 **Rest of RTO** CONE Area, the revealed preferences approach indicated two candidate regions based on our review of recently built or in-development plants: the region along the Pennsylvania-Ohio border and Virginia.[29] Although there have been more resources recently developed in Virginia, the majority of them are regulated and the development is over a larger area. The region along the Pennsylvania-Ohio border currently has three CCs under construction, has attractive energy market net revenues, and is in attainment for 8-hour ozone.

In CONE Area 4 **Western MAAC (WMAAC)**, developers have continued to demonstrate a willingness to build primarily in northeastern Pennsylvania, including areas around Allentown,

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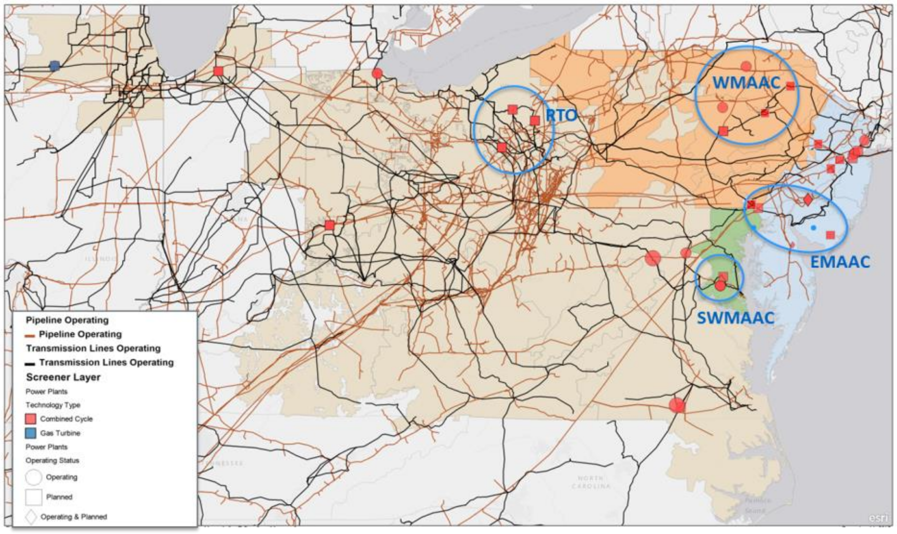
[29] Since the 2014 PJM CONE Study, the Dominion transmission zone has been added to the Rest of RTO CONE Area 3.

Scranton, and Wilkes-Barre. There have been several new units in this region, including two CCs that recently began operation and three more under construction.

Figure 5: Results of Locational Screening for each CONE Area



Sources and notes:
Data on operating and planned projects downloaded from SNL in August 2017.

Table 2: CONE Area Labor Pools

EMAAC	SWMAAC	Rest of RTO	WMAAC
Harrisburg, PA	Annapolis, MD	New Castle, PA	Wilkes-Barre, PA
Baltimore, MD		Youngstown, OH	Scranton, PA
Vineland, NJ		Columbus, OH	Williamsport, PA
Philadelphia, PA			Erie, PA
Dover, DE			

We calculate the plant operating characteristics (*e.g.*, net capacity and heat rate) of the reference resources using turbine vendors' performance estimation software for the combustion turbines' output and GateCycle software for the remainder of the CC plants.[30] For the specified locations within each CONE Area, we estimate the performance characteristics at a representative

[30] GateCycle is a PC-based software application used for design and performance evaluation of thermal power plant systems at both design and off-design points. The GateCycle application allows for detailed analytical models for the thermodynamic, heat transfer, and fluid-mechanical processes within power plants.

elevation and at a temperature and humidity that reflects peak conditions in the median year.[31] The assumed ambient conditions for each location are shown in Table 3.

Table 3: Assumed PJM CONE Area Ambient Conditions

	CONE Area	Elevation *(ft)*	Max. Summer Temperature *(°F)*	Relative Humidity *(%RH)*
1	**EMAAC**	330	92.0	55.5
2	**SWMAAC**	150	96.0	44.6
3	**Rest of RTO**	990	89.8	49.7
4	**WMAAC**	1,200	91.2	49.2

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.

B. Summary of Reference Resource Specifications

Based on the assumptions discussed later in this section, the technical specifications for the CT and CC reference resources are shown in Table 4 and Table 5. Net plant capacity and heat rate are calculated at the ambient air conditions listed above in Table 3.

Table 4: CT Reference Resource Technical Specifications

Plant Characteristic	Specification
Turbine Model	GE 7HA.02
Configuration	1 x 0
Cooling System	n/a
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	352 / 355 / 321 / 344 *
Net Heat Rate (HHV in Btu/kWh)	9,274 / 9,270 / 9,221 / 9,263 *
Environmental Controls	
CO Catalyst	Yes, except for Rest of RTO
Selective Catalytic Reduction	Yes, except for Rest of RTO
Dual Fuel Capability	Yes
Firm Gas Contract	No
Special Structural Req.	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.

31 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 5: CC Reference Resource Technical Specifications

Plant Characteristic	Specification
Turbine Model	GE 7HA.02
Configuration	2 x 1
Cooling System	Mechanical Draft Cooling Tower
Power Augmentation	Evaporative Cooling; no inlet chillers
Net Summer ICAP (MW)	
w/o Duct Firing	1,023 / 1,031 / 1,012 / 1,001 *
with Duct Firing	1,152 / 1,160 / 1,138 / 1,126 *
Net Heat Rate (HHV in Btu/kWh)	
w/o Duct Firing	6,312 / 6,306 / 6,295 / 6,300 *
with Duct Firing	6,553 / 6,545 / 6,532 / 6,537 *
Environmental Controls	
CO Catalyst	Yes
Selective Catalytic Reduction	Yes
Dual Fuel Capability	Yes, except for SWMAAC
Firm Gas Contract	SWMAAC only
Special Structural Req.	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.

C. Plant Size, Configuration and Turbine Model

While the turbine technology for each plant is specified in the tariff (*i.e.*, GE 7FA 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.[32] We reviewed CT and CC projects recently built or under construction in PJM and across the U.S. to determine the configuration, size, and turbine types for the reference resources.

1. Combined-Cycle Turbine Model, Configuration, and Duct Firing

Due to the almost exclusive development of CC plants in PJM in recent years, we focused our analysis of turbine models trends on the CCs. We found that the market is shifting away from the F-class and G-class frame type turbines that have been the dominant turbines over the past several decades and toward the larger H-class and J-class turbines. The larger H-class machine is an incremental evolution of the F-class machine with similar firing technologies. This presents low risk in terms of the maturity of the technology.

As shown in Table 6, over half of the CC plants installed or under construction in PJM since 2014 have installed H/J-class turbines. All of the CCs that cleared in the 2019/20 and 2020/21 BRAs are installing H/J-class turbines. In addition, we reviewed recent orders for GE turbines and

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

found that future CCs are almost exclusively using the H-class turbines.[33] This shows a clear trend toward the H/J-class turbine relative to past studies.[34] We selected the GE 7HA due to its slightly higher installed capacity. Other equivalent machines to the GE H-class machine such as the Siemens 9000HL or the Mitsubishi M501JAC have seen low market penetration in the U.S. at the time of this report. In addition, compared to equivalent models, the GE 7HA has been proven with more operating experience in the industry than other H-class equivalent gas turbine models.

Table 6: Turbine Model of Combined-Cycle Plants Built or Under Construction in PJM since 2014

Turbine Model	PJM Installed Capacity *(MW)*	U.S. Installed Capacity *(MW)*
General Electric 7HA	4,469	7,678
General Electric 7FA	4,436	11,422
Siemens SGT6-8000H	4,228	6,717
Siemens SGT6-5000F	4,140	8,306
Mitsubishi M501J	3,936	4,452
Mitsubishi M501G	2,775	6,310
General Electric 6B	251	251
Siemens SGT6-500	0	642
General Electric LM6000	0	331
Siemens V84.2	0	243
Siemens SGT6-800	0	127
Total	**24,235**	**46,480**
F/G Class Total	11,351	26,039
H/J Class Total	12,633	18,847

Sources and notes:
Data downloaded from ABB Inc.'s Energy Velocity Suite, August 2017.

Reflecting the shifts in turbine models, the size of recently developed CC plants is increasing. Although the most common range remains 700–900 MW as shown in Table 7, there has been 6,000 MW of capacity of new units in the 900–1,100 MW range (compared to 1,300 MW in the 2014 study) and 5,700 MW of units with capacity greater than 1,000 MW. In addition, the most common configuration remains the 2×1 (two gas combustion turbines, one steam turbine).[35] For this reason, we have maintained our assumption that the reference CC is a 2×1 plant.

33 We reviewed GE Power & Water's H-Class Gas Turbine Experience List from November 2016 and the 7F.05 Gas Turbine Experience List from June 2016.

34 In the 2014 CONE Study, there was just 1,500 MW of H/J-class turbines.

35 The CCs that most recently cleared the market are primarily 2x1 units with an average capacity of around 1,000 MW.

Table 7: Capacity and Configuration of CC Plants Built or Under Construction in PJM since 2014

	Plant Summer Capacity Range (MW)							
	< 300	300 - 500	500 - 700	700 - 900	900 - 1,100	1,100 -1,300	> 1,300	Total
CT x ST	*(GW)*	*(GW)*	*(GW)*	*(GW)*	*(GW)*	*(GW)*	*(GW)*	***(GW)***
1 x 1	0.0	1.2	0.0	0.7	0.0	0.0	0.0	**1.9**
2 x 1	0.0	0.0	2.0	6.3	3.9	0.0	0.0	**12.2**
3 x 1	0.0	0.0	0.0	0.0	1.1	0.0	5.7	**6.8**
2 x 2	0.0	0.0	0.6	1.5	1.0	0.0	0.0	**3.1**
Total	**0.0**	**1.2**	**2.6**	**8.6**	**6.0**	**0.0**	**5.7**	**24.0**

Sources and notes:
Data downloaded from ABB Inc.'s Energy Velocity Suite August 2017.

Based on the local ambient condition assumptions in Table 3, we specify the 2×1 CC reference resource's summer capacity to range from 1,001 MW to 1,031 MW prior to considering supplemental duct firing.

For the reference CC plant, supplemental firing of the steam generator, known as "duct firing," increases steam production and hence increases the output of the steam turbine.[36] Duct firing is common, although there is no standard optimized design. The decision to incorporate supplemental firing with the plant configuration and the amount of firing depends on the owner's preference and perceived economic value. We assumed the reference CC plant would add duct firing sufficient to increase the net plant capacity by 125–129 MW, or 13%, close to the average of CC plants constructed since 2007 or in development in PJM of 12%.[37] With duct firing, the max summer net capacity of the CC increases to 1,126–1,160 MW across CONE Areas.[38]

2. Combustion Turbine Model and Configuration

For the CT reference plant, there has been very limited development of frame-type CTs in PJM since 2007, as shown in Table 8. The GE 7FA continues to be the turbine with the most capacity added in PJM since 2007.[39]

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36 Including duct firing increases the net capacity of the plant but reduces efficiency due to the higher incremental heat rate of the supplemental firing (when operating in duct firing mode) and the reduced efficiency of steam turbine (when not operating at full output). The estimated heat rates and capacities take account for this effect.

37 The average incremental capacity provided by including duct firing capabilities for CC plants constructed since 2007 and in development is 12% for plants in PJM and 15% for plants across the US. Data downloaded from ABB Inc.'s *Energy Velocity Suite* in August 2017.

38 The CC is based on a flexible CC design that has become an industry standard due to its ability to accommodate cycle.

39 The three 7FA turbines were added at Dominion's Ladysmith plant in 2008 and 2009.

Table 8: Turbine Model of CT Plants Built or Under Construction in PJM and the U.S. since 2007

Turbine Model	Turbine Class	PJM		U.S.	
		(count)	*(MW)*	*(count)*	*(MW)*
General Electric 7FA	Frame	3	481	26	4,289
Pratt & Whitney FT8	N.A.	6	339	31	1,664
General Electric LM6000	Aeroderivative	7	317	96	4,360
General Electric LMS100	Aeroderivative	3	273	43	4,050
Rolls Royce Corp Trent 60	Aeroderivative	2	124	4	230
Pratt & Whitney FT4000	N.A.	2	120	2	120
Siemens SGT6-5000F	Frame	0	0	14	2,597
General Electric 7EA	Small Frame	0	0	21	1,492
General Electric 7FB	Frame	0	0	3	699
General Electric 7HA	Frame	0	0	2	612
Rolls Royce Corp Unknown	N.A.	0	0	8	480
Pratt & Whitney Unknown	N.A.	0	0	6	332
Westinghouse 501D5	N.A.	0	0	1	121
General Electric LM2500	Aeroderivative	0	0	4	65
Siemens Unknown	N.A.	0	0	2	29
Total		**23**	**1,654**	**263**	**21,140**

Sources and notes:
Data downloaded from ABB Inc.'s Energy Velocity Suite August 2017.

While the GE 7FA remains the most common frame-type turbine to be built since 2007, we reviewed additional sources due to the growing prevalence of the H-class turbines for use in a combined-cycle configuration, including recently proposed CTs in merchant markets, the performance characteristics of the turbines, the projected turbine costs, and PJM's Independent Market Monitor's (IMM's) assumptions for new entrants in the State of the Market report. We found that, although there are limited new frame-type turbines proposed to be built in the U.S. in simple-cycle configuration, both the GE 7FA and GE 7HA are currently being considered for CT development. The 7HA specifically is proposed for the Canal 3 plant in ISO-NE and for the Puente Power Project in CAISO.[40] In addition, the 7HA heat rate and costs on a per-kW basis are more attractive, and PJM's IMM has used the H-class turbine as the basis 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 reference resource 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), reflecting the configuration recently proposed for the CTs with GE 7HA turbines in Massachusetts and California.[41] We specify the

40 The Puente Power Project was cancelled following the recommendation of commissioners of the California Energy Commission to reject the plant following significant intervenor push back.

41 The 2014 PJM CONE study assumed the CT plant included two 7FA turbines ("2×0" configuration).

CT reference resource capacity and heat rate in the CONE Areas based on the local conditions assumptions in Table 3, with the CT capacities ranging from 321 to 355 MW.[42]

D. Detailed Technical Specifications

The majority of the specifications have remained the same as the 2014 CONE Study. In this section, we discuss the fuel supply assumptions and environmental controls. We discuss other technical specifications that are consistent with the 2014 CONE study in Appendix A.

1. Emissions Controls

Emissions control technology requirements for new major stationary sources are determined through the New Source Review (NSR) pre-construction permitting program. The NSR permitting program evaluates the quantity of regulated air pollutants the proposed facility has the "potential to emit" and determines the appropriate emissions control technology/practice required for each air pollutant. The regulated air pollutants that will have the most impact on emissions control technology requirements for new CTs and CCs are nitrogen oxides (NOx) and carbon monoxide (CO).

NOx and CO emissions from proposed gas-fired facilities located in PJM are evaluated through two different types of NSR permitting requirements:

- Non-attainment NSR (NNSR) for NOx emissions (applies to all site locations within the Ozone Transport Region, or OTR); and
- Prevention of Significant Deterioration (PSD) for CO emissions (entire PJM territory) and NOx emissions (eastern Ohio portion of Rest of RTO).

For new facilities located within the OTR, NOx emissions are evaluated through the NNSR permitting program if potential NOx emissions exceed the applicable annual emissions threshold. The OTR includes Delaware, the District of Columbia, Maryland, New Jersey, New York, Pennsylvania, and portions of Virginia. Except for portions of the Rest of RTO, all of the CONE Areas in PJM are within the OTR, and thus emissions of NOx from proposed facilities are treated as a non-attainment air pollutant and evaluated through NNSR. The portion of the Rest of RTO CONE Area identified through the locational analysis in eastern Ohio is currently classified as

[42] Note that we account for the lack of a Selective Catalytic Reduction (SCR) package installed on the CT in the Rest of RTO (CONE Area 3) in setting the max summer capacity of the unit. We describe the basis for not including the SCR in this area in the next section. Without the SCR, the unit is likely to be tuned to reduce NOx emissions, which reduces the max output. We have confirmed that this approach is more economical than installing the SCR and gaining the additional capacity. The developer will have to accept a federally-enforceable annual run-hour limitation.

"attainment," "unclassified," or "maintenance" for 8-hour ozone; therefore, PSD permitting applies to new facilities in the eastern Ohio region if NOx emissions exceed the annual threshold.

New CTs and CCs with no federally enforceable restrictions on operating hours are typically deemed a major source of NOx emissions, and therefore, trigger a Lowest Achievable Emissions Rate (LAER) or Best Available Control Technology (BACT) analysis to evaluate NOx emission control technologies. The NOx emission control technology required by the LAER or BACT analysis is likely to be a selective catalytic reduction (SCR) system. SCR systems are widely recognized as viable technology on aeroderivative and smaller E-class frame combustion turbines and have more recently been demonstrated on F-class frame turbines.[43] In addition, we assume dry low NOx burners are necessary to achieve the required emissions reductions.

CO emissions are evaluated through the PSD permitting requirements, because the PJM region is designated as an attainment area for CO. New combustion turbine facilities with no operating hour restrictions typically have the potential to emit CO in a quantity that exceeds the significant emissions threshold for CO, and therefore, trigger a BACT analysis to evaluate CO emissions control technologies. The CO emissions control technology required as a result of a BACT analysis is likely to be an oxidation catalyst (CO catalyst) system.

Based on our review of the applicable environmental regulations pertinent to new units located in each CONE Area and the emissions rates of the reference resources, we assume an SCR and a CO Catalyst system as the likely requirements resulting from the NSR permitting program for new gas-fired facilities proposed in all CONE Areas, except a new CT in the Rest of RTO area.

For the Rest of RTO region, a new CT unit that primarily fires natural gas is likely to avoid SCR and CO catalyst by installing combustors capable of achieving 9 ppm NOx and 9 ppm CO and accepting a federally-enforced annual run limit that will be set in the range of 20–40%. In western PA, a new CT would likely need to limit annual operation to approximately 20% to keep NOx emissions below the threshold of 50 tons per year. In eastern Ohio region, a new CT would face an annual run limit of approximately 30–40% driven by EPA's greenhouse gas performance standards for new combustion turbines.[44]

The addition of the SCR and CO Catalyst system on the CTs in the non-Rest of RTO regions adds $24 million (in 2017 dollars) to the capital costs.[45] All CCs are equipped with the SCR and CO catalyst at an incremental cost of $50 million (in 2017 dollars).

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[43] CCs with H-class turbines will use an SCR design similar to the F-class turbines. While the exhaust temperature is similar (the 7HA.02 is a bit higher by about 10°F), the exhaust flow of the 7HA.02 is about 35% more than the 7FA.02 and requires a larger tempering air system.

[44] See 40 CFR Part 60 Subpart TTTT.

[45] Including an SCR on the Rest of RTO CT increases the installed costs to $886/kW and CONE to $103,000/MW-year.

2. Fuel Supply Specifications

Natural gas-fired plants can be designed to operate solely on gas or with "dual-fuel" capability to burn both gas and diesel fuel. Dual-fuel plants allow the turbines to switch between the lower cost fuel sources depending on market conditions and fuel availability. An alternative approach for securing fuel supply for gas plants is to procure firm transportation service on the gas pipelines, although in most cases including dual-fuel capabilities is the lower cost approach.[46] In our review of recent generation projects, we found that developers have been choosing in some cases to install dual-fuel capability or obtain firm gas contracts, although several new units have chosen neither option. Adding secure fuel supply capabilities has increased since the 2014 PJM CONE Study following the adoption of the Capacity Performance market design in which units are exposed to incentive payments during shortage conditions.

To reflect the changes in the market rules since the 2014 study, we updated our assumption from the 2014 PJM CONE Study such that the reference CT and CC plants would either install dual-fuel capability or procure firm transportation service in all CONE Areas.[47] Specifically, we assume all units add dual-fuel capabilities, except the SWMAAC CC, which procures firm transportation service.

We assume the dual-fuel plants are equipped with enough liquid fuel storage and infrastructure on-site for three days of continuous operation. Dual-fuel capability requires the combustion turbines to have water injection nozzles to reduce NOx emissions while firing liquid fuel. These modifications as well as the costs associated with fuel oil testing, commissioning, inventory, and the capital carrying charges on the additional capital costs contribute to the overall costs for dual-fuel capability. The incremental cost is approximately $14 million for the CT and $16 million for the CC (in 2017 dollars), including equipment, labor, and materials, indirect costs, and fuel inventory, which contributes approximately $7,000/MW-year to the CONE for the CT and $2,500/MW-year for the CC (in 2022 dollars).

We maintained our assumption that CCs in SWMAAC will obtain firm gas contractions based on the recent experience of new CCs in this area.[48] Both of the CCs recently developed in SWMAAC have entered into long-term firm transportation service contracts to obtain gas on the

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46 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

47 We recommended in the 2014 PJM CONE Study dual-fuel capabilities in all CONE Areas except Rest of RTO. PJM chose to adopt CONE values that incorporated dual-fuel capabilities.

48 We do not assume firm transportation for the reference CT plant since firm gas is unlikely to be economic for a plant that operates at a low capacity factor. We assume the CT will have dual-fuel capability.

Dominion Cove Point (DCP) pipeline.[49] The costs of firm transportation service are incurred annually so we include these costs as fixed operations and maintenance costs in the following section. Firm transportation itself costs about twice as much as installing dual-fuel capability.

IV. Plant Capital Cost Estimates

Plant capital costs are those 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 2017 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 simple- and combined-cycle plants are based on S&L experience on similarly sized and configured facilities and are explained in further detail in Appendix B.

Based on the monthly construction drawdown schedule, we estimate the overnight capital cost in 2022 dollars by escalating the 2017 cost data using reasonable escalation rates. The 2022 "installed cost" is the present value of the construction period cash flows as of the end of the construction period and is calculated using the monthly drawdown schedule and the cost of capital for the project.

A. Plant Capital Cost Summary

Based on the technical specifications for the reference CT and CC described above, the total capital costs for plants with an online date of June 1, 2022 are shown in Table 9 and Table 10 below. The methodology and assumptions for developing the capital cost line items are described further below.

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[49] 153 F.E.R.C. ¶ 61,074 (Issued October 20, 2015).

Table 9: Plant Capital Costs for CT Reference Resource in Nominal $ for 2022 Online Date

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*352 MW*	*355 MW*	*321 MW*	*344 MW*
Owner Furnished Equipment				
Gas Turbines	$74.4	$74.4	$74.4	$74.4
SCR	$26.6	$26.6	$0.0	$26.6
Sales Tax	$6.7	$6.1	$4.7	$6.4
Total Owner Furnished Equipment	**$107.7**	**$107.1**	**$79.1**	**$107.4**
EPC Costs				
Equipment				
Other Equipment	$25.7	$25.6	$28.5	$25.7
Construction Labor	$43.5	$31.8	$31.0	$37.6
Other Labor	$16.5	$15.3	$12.9	$16.0
Materials	$6.6	$6.5	$6.5	$6.6
Sales Tax	$2.1	$1.9	$2.2	$2.0
EPC Contractor Fee	$20.2	$18.8	$16.0	$19.5
EPC Contingency	$22.2	$20.7	$17.6	$21.5
Total EPC Costs	**$136.8**	**$120.5**	**$114.8**	**$128.9**
Non-EPC Costs				
Project Development	$12.2	$11.4	$9.7	$11.8
Mobilization and Start-Up	$2.4	$2.3	$1.9	$2.4
Net Start-Up Fuel Costs	$2.6	$1.7	$0.2	$0.6
Electrical Interconnection	$7.8	$7.8	$7.1	$7.6
Gas Interconnection	$29.1	$29.1	$29.1	$29.1
Land	$0.4	$0.7	$0.3	$0.5
Fuel Inventories	$3.0	$3.0	$2.7	$2.9
Non-Fuel Inventories	$1.2	$1.1	$1.0	$1.2
Owner's Contingency	$4.7	$4.6	$4.2	$4.5
Financing Fees	$8.0	$7.5	$6.5	$7.7
Total Non-EPC Costs	**$71.4**	**$69.2**	**$62.6**	**$68.3**
Total Capital Costs	**$316.0**	**$296.8**	**$256.5**	**$304.7**
Overnight Capital Costs ($million)	**$316**	**$297**	**$257**	**$305**
Overnight Capital Costs ($/kW)	**$898**	**$836**	**$799**	**$886**
Installed Cost ($/kW)	**$938**	**$874**	**$835**	**$925**

Table 10: Plant Capital Costs for CC Reference Resource in Nominal $ for 2022 Online Date

	CONE Area			
	1	2	3	4
	EMAAC	SWMAAC	Rest of RTO	WMAAC
Capital Costs (in $millions)	*1152 MW*	*1160 MW*	*1138 MW*	*1126 MW*
Owner Furnished Equipment				
Gas Turbines	$173.2	$167.5	$173.2	$173.2
HRSG / SCR	$55.4	$53.6	$55.4	$55.4
Sales Tax	$15.1	$13.3	$14.5	$14.5
Total Owner Furnished Equipment	**$243.8**	**$234.4**	**$243.1**	**$243.1**
EPC Costs				
Equipment				
Condenser	$5.8	$5.8	$5.8	$5.8
Steam Turbines	$47.1	$45.5	$47.1	$47.1
Other Equipment	$74.7	$72.1	$74.7	$74.7
Construction Labor	$211.1	$159.3	$167.4	$187.2
Other Labor	$56.5	$50.6	$52.5	$54.3
Materials	$51.5	$51.2	$51.5	$51.5
Sales Tax	$11.9	$10.5	$11.4	$11.4
EPC Contractor Fee	$70.2	$62.9	$65.3	$67.5
EPC Contingency	$77.3	$69.2	$71.9	$74.3
Total EPC Costs	**$606.1**	**$527.3**	**$547.6**	**$573.7**
Non-EPC Costs				
Project Development	$42.5	$38.1	$39.5	$40.8
Mobilization and Start-Up	$8.5	$7.6	$7.9	$8.2
Net Start-Up Fuel Costs	$0.8	-$5.5	-$10.5	-$7.2
Electrical Interconnection	$25.5	$25.6	$25.2	$24.9
Gas Interconnection	$29.1	$29.1	$29.1	$29.1
Land	$1.5	$2.7	$1.0	$2.0
Fuel Inventories	$6.9	$0.0	$6.8	$6.7
Non-Fuel Inventories	$4.2	$3.8	$4.0	$4.1
Owner's Contingency	$9.5	$8.1	$8.2	$8.7
Emission Reduction Credit	$2.2	$2.2	$2.2	$2.2
Financing Fees	$25.5	$22.7	$23.5	$24.3
Total Non-EPC Costs	**$156.1**	**$134.4**	**$136.9**	**$143.9**
Total Capital Costs	**$1,006.0**	**$896.1**	**$927.6**	**$960.7**
Overnight Capital Costs ($million)	**$1,006**	**$896**	**$928**	**$961**
Overnight Capital Costs ($/kW)	**$873**	**$772**	**$815**	**$853**
Installed Cost ($/kW)	**$951**	**$841**	**$887**	**$929**

B. Plant Proper Capital Costs

1. Plant Developer and Contractor 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.

2. Equipment and Sales Tax

"Major equipment" includes costs associated with the gas turbines, HRSG, SCR, condenser, and steam turbines, where applicable. Note that the gas turbines for the CC cost more per turbine than for the CT because the manufacturer includes additional valves, gas pre-treatment, and other components that are required for CC operation.

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. A sales tax rate specific to each CONE Area is applied to the sum of major equipment and other equipment to account for the sales tax on all equipment.[50]

3. Labor and Materials

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.

50 See the sales tax listed in Table 21 below.

Similar to the 2014 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, the labor rates have been developed by S&L through a survey of the prevalent wages in each region in 2017, 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 B.

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.

4. 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 CT and CC facilities based on S&L's proprietary project cost database. This value is lower than the 12% assumed in the 2014 PJM CONE Study for the CC facilities based on recent project history and current market trends.

"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, similar to the EPC contractor fee.

The overall contingency rate in this analysis (including the Owner's Contingency presented in the next section) is 9.3% to 9.5% of the pre-contingency overnight capital costs, slightly lower than the 9.6% in the 2014 Study due to lower Owner's Contingency, as explained below.

C. Owner's Capital 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.

1. 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.

2. Net Startup Fuel Costs

Before commencing full commercial operations, new generation 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 and ultra-lower sulfur diesel (ULSD) if dual-fuel capability is specified. 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 fuel oil consumption, and will receive revenues for its energy production. We provide additional detail on the calculation of the net startup fuel costs in Appendix B.

3. 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. In the 2014 PJM CONE Study the cost was small enough to be absorbed by the project development costs. Due to the large capacity of the units in the current study this assumption is no longer valid and the ERCs are included as a separate capital cost. ERCs are priced on a dollar per ton basis and are dependent on market conditions. Based on our research we have assumed a cost of $5,000/ton and an offset ratio of 1.15 for NOx and VOC emissions, resulting in a one-time cost of $2 million (in 2017 dollars) prior to beginning operation of the CC plants. CT plants are not required to purchase ERCs because they are not projected to exceed the NSR threshold.

4. 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 2014 PJM CONE Study. From the data summarized in Appendix B, we estimate that gas interconnection costs for both the CT and CC will be $26.2 million (in 2017 dollars) based on $4.6 million/mile and $3.4 million for a metering station. Similar to the 2011 and 2014 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 2014 and 2017, we selected 12 projects (8,326 MW of total capacity) that are representative of interconnection costs for a new gas CT or CC and calculated a capacity-weighted average electrical interconnection cost of $19.9/kW (in 2017 dollars) for these projects, 33% lower than the 2014 CONE Study. The estimated electric interconnection costs are approximately $7 million for CTs and $23 million for CCs (in 2017 dollars). Appendix B presents additional details on the calculation of electric interconnection costs.

5. 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. A summary of the land costs are available in Appendix B. Table 11 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 needed for CT and 40 acres for CC.

Table 11: Cost of Land Purchased

CONE Area	Land Price (\$/acre)	Plot Size Gas CT (acres)	Plot Size Gas CC (acres)	Cost Gas CT (\$m)	Cost Gas CC (\$m)
1 EMAAC	$36,300	10	40	$0.36	$1.45
2 SWMAAC	$66,700	10	40	$0.67	$2.67
3 RTO	$26,200	10	40	$0.26	$1.05
4 WMAAC	$51,100	10	40	$0.51	$2.04

Sources and notes:
We assume land is bought in 2018, *i.e.*, 6 months to 1 year before the start of construction.

6. Fuel and Non-Fuel Inventories

Non-fuel inventories refer to the initial inventories of consumables and spare parts that are normally capitalized. We assume non-fuel working capital is 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.

We calculated the cost of the fuel inventory in areas with dual-fuel capability assuming a three day supply of ULSD fuel will be purchased prior to operation at a cost of $1.77/gallon, or $12.63/MMBtu (in 2022 dollars), based on current futures prices.[51]

7. 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.* We assumed an owner's contingency of 8% of Owner's Costs, which is lower than we assumed in previous reports (9% in the 2014 CONE Study) based on S&L's review of the most recent projects for which it has detailed information on actual owner's costs.

8. 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.[52] As explained below, the project is assumed to be 65% debt financed and 35% equity financed, an increase from 60% debt financed in the 2014 CONE Study.

D. Escalation to 2022 Installed Costs

S&L developed monthly capital drawdown schedules over the project development period for each technology: 36 months for CCs and 20 months for CTs.[53] We escalated the 2017 estimates

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51 Futures prices calculated using NY Harbor USLD and Brent Crude Oil futures. Data from Bloomberg, representing trade dates 07/31/2017 to 10/31/2017.

52 As discussed in the Financial Assumptions section, we assume the plant is financed through a 60% debt and 40% equity capital structure.

53 For CTs, the construction drawdown schedule occurs over 20 months with 80% of the costs incurred in the final 11 months prior to commercial operation. For CCs, the construction drawdown schedule occurs over 36 months with 80% of the costs incurred in the final 20 months prior to commercial operation.

of overnight capital cost components forward to the construction period for a June 2022 online date using cost escalation rates particular to each cost category.

We estimated real escalation rates based on long-term (approximately 20-year) historical trends relative to the general inflation rate for equipment and materials and labor. The real escalation rate for each cost category was then added to the assumed inflation rate of 2.2% (see Section VI.A) to determine the nominal escalation rates, as shown in Table 12.

Table 12: Capital Cost Escalation Rates

Capital Cost Component	Real Escalation Rate	Nominal Escalation Rate
Equipment and Materials	0.20%	2.40%
Labor	1.70%	3.90%

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 2017 overnight costs using the monthly capital drawdown schedule developed by Sargent & Lundy for an online date in June 2022.

However, 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 2022 online date, the land is thus assumed to be purchased in late 2018 such that current estimates are escalated 1 year using the long-term inflation rate of 2.2%.
- **Net Start-Up Fuel and Fuel Inventories**: no escalation was needed as we forecasted fuel and electricity prices in 2022 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 2014 CONE Study; the interconnection costs have been escalated specifically to these months.
- **Emission Reduction Credits**: escalated to the online start date of June 2022 using the long-term inflation rate of 2.2%.

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 2022 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 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.

V. Operation and Maintenance Costs

Once the plant enters commercial operation, the plant owners incur fixed O&M costs each year, including property tax, insurance, labor, minor 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) to inform PJM's future E&AS margin calculations.

A. Summary of O&M Costs

Table 13 and Table 14 summarize the fixed and variable O&M for plants with an online date of June 1, 2022. In Appendix C, we provide alternative O&M cost estimates in which we include major maintenance costs as fixed O&M.

Table 13: O&M Costs for CT Reference Resource

	CONE Area			
O&M Costs	**1 EMAAC** *352 MW*	**2 SWMAAC** *355 MW*	**3 Rest of RTO** *321 MW*	**4 WMAAC** *344 MW*
Fixed O&M (2022$ million)				
LTSA	$0.3	$0.3	$0.3	$0.3
Labor	$1.1	$1.2	$0.8	$0.9
Maintenance and Minor Repairs	$0.5	$0.5	$0.5	$0.5
Administrative and General	$0.2	$0.2	$0.2	$0.2
Asset Management	$0.5	$0.6	$0.4	$0.4
Property Taxes	$0.3	$4.1	$1.8	$0.3
Insurance	$1.9	$1.8	$1.5	$1.8
Working Capital	$0.04	$0.03	$0.03	$0.03
Total Fixed O&M (2022$ million)	**$4.8**	**$8.7**	**$5.6**	**$4.4**
Levelized Fixed O&M (2022$/MW-yr)	**$13,600**	**$24,400**	**$17,300**	**$12,600**
Variable O&M (2022$/MWh)				
Consumables, Waste Disposal, Other VOM	1.10	1.10	0.95	1.10
Total Variable O&M (2022$/MWh)	**1.10**	**1.10**	**0.95**	**1.10**
Major Maintenance - Starts Based ($/factored start, per turbine)	**23,464**	**23,464**	**23,464**	**23,464**

Table 14: O&M Costs for CC Reference Resource

O&M Costs	CONE Area 1 EMAAC *1152 MW*	2 SWMAAC *1160 MW*	3 Rest of RTO *1138 MW*	4 WMAAC *1126 MW*
Fixed O&M (2022$ million)				
LTSA	$0.5	$0.5	$0.5	$0.5
Labor	$5.8	$6.3	$4.4	$4.6
Maintenance and Minor Repairs	$5.9	$6.1	$5.4	$5.5
Administrative and General	$1.3	$1.4	$1.1	$1.2
Asset Management	$1.6	$1.7	$1.2	$1.3
Property Taxes	$2.0	$12.3	$7.1	$1.9
Insurance	$6.0	$5.4	$5.6	$5.8
Firm Gas Contract	$0.0	$9.7	$0.0	$0.0
Working Capital	$0.1	$0.1	$0.1	$0.1
Total Fixed O&M (2022$ million)	**$23.3**	**$43.5**	**$25.4**	**$20.9**
Levelized Fixed O&M (2022$/MW-yr)	**$20,200**	**$37,500**	**$22,300**	**$18,600**
Variable O&M (2022$/MWh)				
Major Maintenance - Hours Based	1.44	1.44	1.44	1.44
Consumables, Waste Disposal, Other VOM	0.67	0.67	0.67	0.67
Total Variable O&M (2022$/MWh)	**2.11**	**2.11**	**2.11**	**2.11**

B. 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).

1. 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. Each major maintenance cycle for a combustion turbine typically includes regular combustion inspections, periodic hot gas path inspections, and one major overhaul. We include the costs of long-term maintenance as variable O&M and monthly LTSA payments as fixed O&M.

Consistent with past CONE studies, we assume major maintenance and overhaul costs often specified in an LTSA are included as variable O&M costs. Separately, in Appendix C, we present alternative O&M costs and CONE values corresponding to PJM's current cost guidelines, which specify that major maintenance costs cannot be considered to be variable costs in cost-based energy offers.[54] We include the alternative cost and CONE estimates in the appendix because it differs from past CONE studies (so is harder to compare) and might not turn out to be appropriate if PJM's cost guidelines change. Indeed, PJM stakeholders' Markets Implementation Committee is addressing whether the PJM cost guidelines should be modified to allow major maintenance costs to be included in variable O&M costs.

2. Insurance and Asset Management Costs

We calculated insurance costs as 0.6% of the overnight capital cost per year, based on a sample of independent power projects recently under development in the Northeastern U.S. and discussions with a project developer. This value is consistent with the 2014 PJM CONE Study. We estimated the asset management costs from typical costs incurred for fuel procurement, power marketing, energy management, and related services from a sample of CT and CC plants in operation.

3. Property Tax

To estimate property tax, we researched tax regulations for the locations selected in each CONE Area, averaging the tax rates in the areas that include multiple states. We estimated the property taxes through bottom-up cost estimates that separately evaluated taxes on real property (including land and structural improvements) and personal property (the remainder of the plant) in each location. In this study, we did not incorporate any assumed Payment in Lieu of Taxes (PILOT) agreements. Although PILOT agreements could be executed between an individual plant developer and a county, these agreements are individually negotiated and may not be available on a similar basis for all plants.

Real property is taxed in all states containing reference plant locations we selected for the CONE Area. Personal property is taxed only in SWMAAC (Maryland) and Rest of RTO (Ohio). For power plants, the value of personal property tends to be much higher than the value of real property, since equipment costs make up the majority of the total capital cost. For this reason, property taxes for plants located in states that impose taxes on personal property will be significantly higher than plants located in states that do not.

To estimate real property taxes, we assumed the assessed value of land and structural improvements is the initial capital cost of these specific components. We determined assessment ratios and tax rates for each CONE Area by reviewing the publicly-posted tax rates for several counties within the specified locations and by contacting county and state tax assessors. (The tax rates assumed for each CONE Area are summarized in Table 15 with additional details in Appendix B.) We multiply the assessment ratio by the tax rate to determine the overall effective

[54] PJM, PJM Manual 15: Cost Development Guidelines, pp. 15–29.

tax rate, and apply that rate to our estimate of assessed value. We assume that assessed value of real property will escalate in future years with inflation.

Table 15: 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	3.7%	n/a	n/a
2	**SWMAAC**			
	Maryland	1.1%	1.4%	3.3%
3	**RTO**			
	Ohio	2.0%	1.4%	See "SchC-NewProd (NG)" schedule
	Pennsylvania	2.5%	n/a	n/a
4	**WMAAC**			
	Pennsylvania	3.5%	n/a	n/a

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

Personal property taxes in the states of Maryland, Ohio, and Pennsylvania were estimated using a similar approach. As with real property, we multiply the local tax rate by the assessment ratio to determine the effective tax rate on assessed value. 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. For example, in Maryland, personal property is subject to straight-line depreciation of 3.3% per year.

4. Working Capital

We estimated the cost of maintaining working capital requirements for the reference CT and CC by first estimating the working capital requirements (calculated as accounts receivable minus accounts payable) as a percent of gross profit for 3 merchant generation companies: NRG, Calpine, and Dynegy. The weighted-average working capital requirement among these companies is 4.2% of gross profits.[55] Translated to the plant level, we estimate that the working capital requirement is approximately 0.8% of overnight costs in the first operating year (increasing with inflation thereafter). In the capital cost estimates, we do not include the working capital requirements but instead the cost of maintaining the working capital requirement based on the borrowing rate for short-term debt for BB rated companies 2.2%.[56]

[55] Gross profits are revenues minus cost of goods sold, including variable and fixed O&M costs.

[56] 15-day average 3-month bond yield as of October 27, 2017, BFV USD Composite (BB), from Bloomberg.

5. Firm Transportation Service Contract in SWMAAC

The gas pipeline serving the part of SWMAAC we identified for the reference plants is the Dominion Cove Point (DCP) pipeline. We understand from shippers that they have had trouble obtaining gas on the DCP pipeline. Availability of interruptible service has been unreliable and inflexible with the pipeline being fully subscribed and unable to absorb substantial swings in usage within a day. To at least partially address this problem, we assume new CC plants will contract for firm transportation service on DCP. We assume that the new CT will not acquire firm service due to the relatively few hours such a plant is expected to operate.

To estimate the costs of acquiring firm transportation service on the DCP pipeline for a plant coming online in 2022, we assume the same transportation reservation rate on DCP as that filed for the St. Charles and Keys projects. The rates for St. Charles and Keys are $3.7417 and $5.4278 per dekatherm respectively for 2017 (St. Charles) and 2018 (Keys).[57] We then escalate to 2022 dollars, resulting in rates of $4.21 and $5.97 per dekatherm,[58] resulting in a $9.7 million annual cost, adding $9,800/MW-year to the CONE for CCs in SWMAAC. We provide additional detail on the cost calculation of acquiring firm transportation service in Appendix B.

C. Variable Operation and Maintenance Costs

Variable O&M costs are not used in calculating CONE, but they inform the E&AS revenue offset calculations performed annually 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 costs related to major maintenance that are often specified in an LTSA are considered variable O&M costs, consistent with past CONE studies. We provide alternative O&M costs and CONE estimates with these costs considered to be fixed O&M costs in Appendix C.

D. Escalation to 2022 Costs

We escalated the components of the O&M cost estimates from 2017 to 2022 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 12) have been used to escalate the O&M costs. The assumed real escalation rate for labor is 1.7% per year, while those for other O&M costs are 0.2% per year.

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57 153 F.E.R.C. ¶ 61,074 (Issued October 20, 2015).

58 This does not include variable charges, which should not be included in CONE but should be accounted for in estimating energy margins to calculate Net CONE.

VI. Financial Assumptions

A. 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).[59] 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, and a final adjustment for the recent changes in corporate taxes.[60] Based on the empirical analysis completed in November 2017 under the then 35% federal tax rate,[61] we would have recommended 7.0% as the appropriate ATWACC to set the CONE price for a new merchant plant that will commence operation by 2022 (4.5 years from now assuming a mid-year commercial operation). Consistent with this ATWACC determination under the 35% federal tax rate regime, we would have recommended the following specific components for a new merchant plant: a capital structure of 65/35 debt-equity ratio, cost of debt 6.5% and return on equity (ROE) of 12.8%.[62]

After we completed the initial analysis in early November of 2017 for the 35% corporate tax rates, the U.S. Congress passed the Tax Cuts and Jobs Act. These changes in the tax system raise an immediate question: what is the impact of the tax law changes on cost of capital? For example, the cut in the federal corporate income tax rate reduces the tax advantage of debt relative to equity, which could lead to a higher equity ratio and, combined with a higher after-tax cost of debt, a higher ATWACC. But, the law changes are more fundamental and involve

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59 The "after-tax weighted-average cost of capital" (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).

60 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.

61 We choose November 2017 as the cutoff date so that we can obtain the latest quarterly financial reports by the sample companies. Annual 2017 financial reports for SEC-registered companies will not be filed until March 2018.

62 $6.5\% \times 65\% \times (1 - 40.5\%) + 12.8\% \times 35\% = 7.0\%$. The tax rate of 40.5% is a combined federal-state tax rate, where state taxes are deductible for federal taxes ($= 8.5\% + (1 - 8.5\%) \times 35\%$). Note that the ATWACC applied to the four CONE Areas varies very slightly with applicable state income tax rates, as discussed in the following section.

more than a cut in the federal corporate tax rate. Other major changes include the transition from a worldwide tax system to a territorial tax system and immediate expensing of qualified investments. Ultimately, estimating the cost of capital is an empirical matter to be based on the market data. Because of the fundamental changes introduced in the new tax law and near-term uncertainties around its interpretations and implementations, it will take time for companies and individuals to adjust investment/consumption and financing decisions and for the impacts on the cost of capital to be observable and estimable.

Since we need to recommend the CONE value for a reference resource before these uncertainties are fully resolved, we have to predict the likely impact of the new tax law on merchant generator cost of capital without a substantial body of empirical data. We thus focus our analysis on what changes in the companies' capital structure (equity and debt ratios), if any, would likely result from the most prominent change in the new law—the reduction in federal corporate income tax from 35% to 21%. This is a critical first step, as an investment's cost of equity and cost of debt depend on its capital structure.[63] Our review of the recent economic literature, both theoretical and empirical, regarding the tax impacts on capital structure suggest that the drop in federal income tax rate is unlikely to have a material impact on the firms' capital structure (see further details below). Therefore, we recommend the same cost of capital components (cost of equity, cost of debt (COD), and debt/equity ratios) that we have developed from the available empirical information under the 35% federal tax rate. Under these assumptions, the reduction of the federal tax rate to 21% reduces the debt tax shield and thus increases the ATWACC to 7.5%.[64]

As a point of reference, we summarize our two previous costs of capital recommendations under the old 35% federal tax rate and the current 2018 recommendation in Table 16 under both the 35% and 21% tax rates. Historical comparison can be easily made in the first three rows of Table 16 (all under the same tax rate). In the 2014 PJM CONE Study, we recommended an ATWACC of 8.0%.[65] At a slightly higher equity ratio (60/40), the cost of debt and return on equity were set at 7.0% and 13.8%, respectively. In 2011, we recommended a debt/equity ratio of 50/50, based on the market-value capital structure at the time. In the last six years, the equity ratios have declined, as the U.S. IPP industry continued its restructuring activities.

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63 Conceptually, the ATWACC is relatively constant over a broad range of capital structure ratios. In other words, tax deductibility of interest payments has a secondary if not negligent impact on cost of capital.

64 Under the new tax law, state taxes are not deductible. The combined state and federal tax rate for Maryland (SWMAAC) is then 21% + 8.25% = 29.25%. Thus, the ATWACC is estimated based on a 6.5% cost of debt, a 12.8% cost of equity, and a 35% equity ratio as follows: 6.5% × 65% × (1 – 29.25%) + 12.8% × 35% = 7.5%.

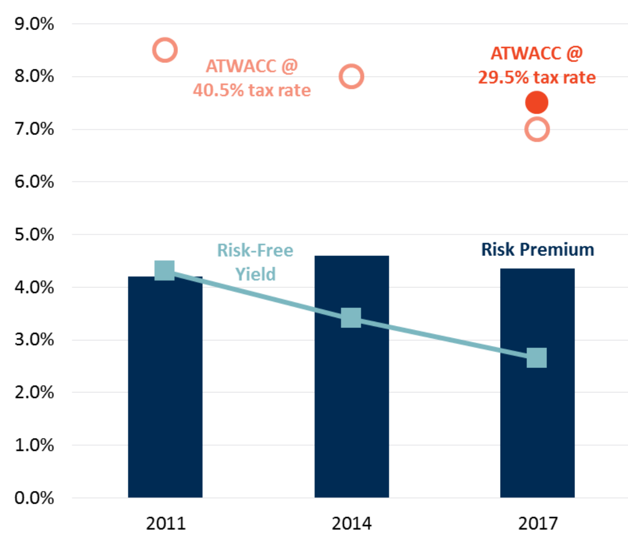
65 As discussed in our 2014 CONE report, our recommended 8.0% ATWACC was slightly above our ATWACC estimate for individual IPPs (7.8% for Calpine and 6.1% for both Dynegy and NRG), but within the range of cost of capital as suggested by the fairness opinions and analysts.

Table 16: Comparison of Cost of Capital Recommendations
(2011–17 at 40.5% combined federal/state tax rate vs. 2018 at 29.5% combined tax rate)

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	40.5%	12.8%	35%	6.5%	65%	7.0%
2018	**29.5%**	12.8%	35%	6.5%	65%	7.5%

The 2011–2018 reduction in ATWACC in our recommendations can be traced primarily to the fall in the long-term risk-free interest rate between 2011 to November 2017, with a partially offsetting increase from the lower tax rate.[66] This can be seen in Figure 6, where the red circles represent our ATWACC recommendations under the 35% federal tax rate, the red dot shows the ATWACC recommendation as a result of the tax law change, and the teal line displays the movement in risk-free rates. The risk premiums (ATWACC less risk-free rate) are shown in the blue bars. Viewed from this perspective, the risk premium implied from our current ATWACC recommendation is in line with the risk premiums implied in our 2011 and 2014 recommendations.[67] The ATWACC recommended as a result of the tax law change uses the same components (ROE, COD, and capital structure), except for the tax rate.

Figure 6: Comparison of Brattle Cost of Capital Recommendations for PJM



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

[66] 20-year U.S. treasury yields increased slightly from November 2017 (about 2.6%) to mid-January 2018 (close to 2.8%).

[67] In general, the fall in long-term risk-free rate caused ROE and Cost of Debt to fall, although the reduction is not uniform: as the market-value debt ratio increases from 50% in 2011 to 60% in 2014, our recommended ROE in 2014 increased relative to the 2011 recommendation.

The rest of this discussion proceeds in four topics to further document our approach to developing the recommended ATWACC. The first three are based on a 35% federal tax rate, as the empirical data are all related to corporate behaviors under the prior tax regime. First, we perform an independent cost of capital analysis for U.S.[68] and Canadian IPPs.[69] Second, we present evidence on the discount rates disclosed in fairness opinions for two recent merger and acquisition transactions involving U.S. IPPs.[70] Third, we discuss how considerations of the specific dynamics of PJM markets affect cost of capital recommendations. Finally, we discuss how cost of capital is expected to change due to the reduction in federal tax rate.

ATWACC for Publicly Traded Companies: We calculated ATWACC estimates using the following standard techniques with results summarized in Table 17 and charted with sensitivities in Figure 7. While we primarily rely on the estimated ATWACC results for the U.S. IPPs, Table 17 shows that the ATWACC results for the Canadian IPPs are in the same range as for the U.S. IPPs. For ease of presentation, Canadian IPP ATWACCs are not plotted in Figure 7.

Return on Equity: We estimate the required return on equity (ROE or cost of equity) using the Capital Asset Pricing Model applied to samples of U.S. and Canadian merchant generation companies. 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."[71] In Table 17, we use a risk-free rate of 2.65%, a 15-day average of 20-year U.S. treasuries as of October 2017, as our base case. We estimate the expected risk premium of the market to be 6.9% based on the long-term average of values provided by Duff and Phelps.[72] 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. The resulting required return on equity ranges from 8.5 to 12.8% for the sample companies included in the analysis. Because most of the sample companies will have

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68 The financial characteristics of the sample companies vary on an individual basis. For example, GenOn, a large subsidiary of NRG Energy filed for bankruptcy in June 2017 and will be restructured as a standalone business. Calpine announced it will be acquired by a private investor consortium while Dynegy will be acquired by Vistra Energy. We believe that these companies, each in differing positions, still can provide useful reference points for estimating the cost of capital for a merchant generator.

69 Since the U.S. IPP industry has been in the middle of restructuring and consolidation during the last five years, we consider a sample of Canadian IPPs as additional comparable companies.

70 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.

71 See, for example, Richard Brealey, Stewart C. Myers, and Franklin Allen (2011), *Principles of Corporate Finance*. New York: McGraw-Hill/Irwin (Chapter 8).

72 Duff and Phelps International Guide to Cost of Capital, 2017(arithmetic average of excess market returns over 20-year risk-free rate from 1926 to 2016).

various proportion of their generation assets under long-term contracts (*i.e.*, not operating on a purely merchant basis), we look to the upper range of these results as a reasonable estimate for the cost of equity of merchant generation investments in PJM.[73]

In addition to this baseline analysis under current market conditions, we consider the use of forecasted risk-free rates applicable for three years to reflect the fact that the ATWACC will be used to estimate offer prices of new merchant entrants that are supposed to start operation in 2022. The average 10-year Treasury yields of BlueChip's 5 year forecast (2019 to 2023) is 3.5%.[74] Adding a maturity premium (20-year bond yields over 10-year bond yields) of 0.54%, we estimate the 20-year risk-free rate to be 4.04% and use this as a sensitivity to our baseline ATWACC analysis, as shown in Figure 7 below (along with ATWACC benchmarks using fairness opinions from recent transactions as discussed further below).

Cost of Debt: In our 2011 and 2014 analyses, we estimated the COD based on the average bond yields corresponding to the unsecured senior credit ratings for each merchant generation company (issuer ratings).[75] The rating-based average yields, based on a sample of similarly-rated long-term (10-plus years) corporate bonds, are generally more preferable than the company's actual COD, which could be more influenced by company- and issue-specific factors.[76] 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 BB-based and B-based average yields for the general corporate bonds have dropped by more than 1.5 percent since 2016 and U.S.-based IPPs' company-specific bond yields are consistently higher than the rating-based yields. Therefore, in the current estimation (as shown in Table 17), we use the company-specific bond yield as our baseline case. (The rating-based yields are shown as Sensitivities 1 and 3 in Figure 7.)

Debt/Equity Ratio: We estimated the five-year average debt/equity ratio for each merchant generation company using data from Bloomberg as shown in Table 17.

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73 Note that, because of the 3-year forward nature of the PJM capacity market and its sloping demand curve, PJM merchant generation risks will be lower than the risk of merchant generation assets that do not have the benefit of a PJM-style capacity market (*e.g.*, as is the case in ERCOT and uncontracted plants in CAISO).

74 Blue Chip Economic Indicators (2017), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers, October 2017.

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

76 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 CODs. For example, the sample companies' credit ratings range from "BBB," with an associated COD of 3.5% to "B+," with an associated 5.0% COD. Using company-specific CODs, the range increases to 4.2–7.3%.

Table 17: Baseline ATWACC for the Publicly Traded Merchant Generation Companies (35% Federal Tax Rate)

Company	Firm Value [1]	S&P Credit Rating [2]	Equity Beta [3]	Return on Equity [4]	Cost of Debt [5]	Debt/ Equity Ratio [6]	After Tax WACC [7]
NRG Energy Inc	$23,278	BB-	1.17	10.7%	5.8%	73/27	5.4%
Calpine Corp	$16,586	B+	1.06	10.0%	5.6%	63/37	5.8%
Dynegy Inc	$9,903	B+	1.25	11.3%	6.7%	66/34	6.5%
TransAlta Corp	$4,020	BBB-	1.47	12.8%	6.3%	66/34	6.8%
Algonquin Power & Utilities Corp	$7,676	BBB	0.84	8.5%	5.1%	46/54	6.0%
Northland Power Inc	$9,003	BBB	0.92	9.0%	5.1%	58/42	5.6%
Capital Power Corp	$3,723	BBB-	0.95	9.2%	3.9%	47/53	6.0%

Sources and Notes:

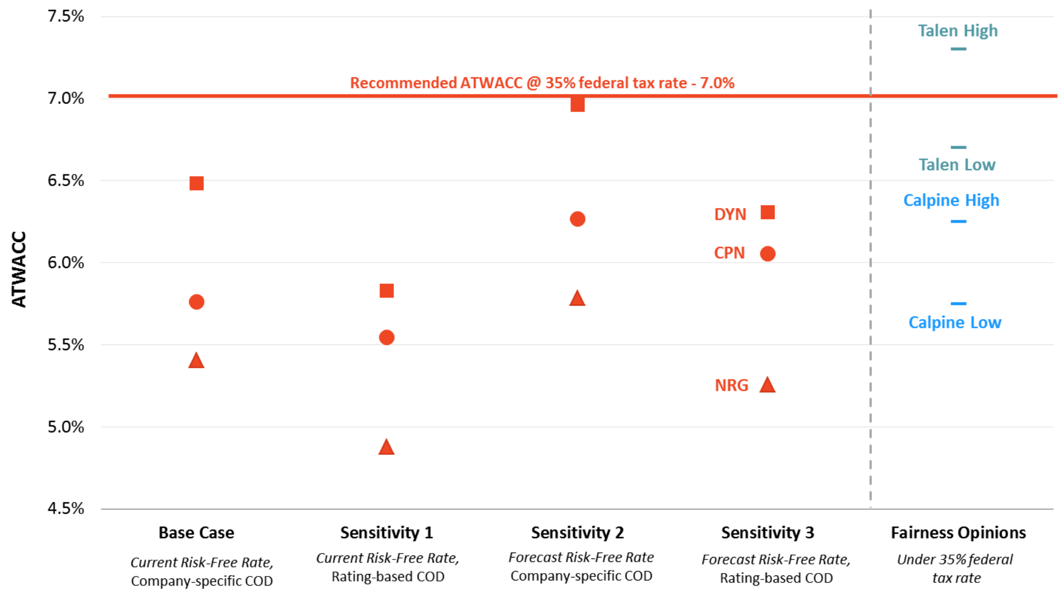
[1]: Market value of equity + Book value of debt, Bloomberg as of 11/1/2017
[2]: S&P Research Insight, Algonquin and Capital Power from SNL
[3]: Company-specific, Bloomberg as of 11/1/2017
[4]: Assumed risk-free rate (2.65%) + assumed market risk premium (6.90%) × [3]
[5]: Bloomberg as of 11/1/2017
[6]: Capital Structure calculated by Brattle using company 10-Ks and Bloomberg data
[7]: (% Debt) × [5] × (40.5% Combined state and federal tax rate; assumes 8.5% state tax rate) + (% Equity) × [4]

Figure 7 reports the ATWACC for the U.S. merchant sample (NRG, Calpine, and Dynegy) 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 17 above.
- *Sensitivity 1* uses the ratings-based COD, as used in previous PJM CONE studies.
- *Sensitivity 2* uses the forecasted risk-free rate.
- *Sensitivity 3* uses both the ratings-based COD and the forecasted risk-free rate.
- *Fairness Opinions* are from recent transactions (as discussed below).

As of November 2017, the federal tax rate was 35%. For the Base Case and each sensitivity (the first columns in Table 17), the red marks represent each of three U.S. IPPs' ATWACCs. For example, under Sensitivity 1, the ATWACCs (red marks) range approximately from 4.9% to 5.9%. Under the other two scenarios when the forecasted risk-free rate is used, the upper end of the ATWACC approached 7.0% (Sensitivity 2) and 6.3% (Sensitivity 3).

Figure 7: ATWACCs of U.S. IPPs and Discount Rates from Fairness Opinions (35% Federal Tax Rate)



Cost of Capital Benchmarks from Recent Fairness Opinions: Additional cost of capital reference points shown on the right side of Figure 7 above come from publicly-available values 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. For the current analysis, we found two additional reference points to inform the recommended ATWACC. The discount rate range disclosed in the June 2017 fairness opinion for the pending Calpine acquisition by Energy Capital Partners is 5.75% to 6.25%.[77] Another relevant reference point is the disclosed range of discount rate used in the acquisition of Talen Energy by Riverstone Holdings of 6.7% to 7.3%, released in December 2015.[78] We include these values in the figure above to compare the estimated ATWACC for publicly-traded companies under alternative assumptions for the risk-free rate and COD.

Estimated ATWACC for Merchant Generators in PJM Markets (before consideration of lower corporate tax rate): 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

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

78 Preliminary Proxy Statement, Schedule 14A, filed by Talen Energy Corporation with SEC on July 1, 2016. Since December 2015 (the as-of date of the Talen discount rates), the 20-year risk-free rate has stayed about the same level. In December 2015 the 20-year risk-free yield was 2.61%, while as of 10/31/2017 it is 2.65% according to Bloomberg.

than for the average portfolio of independent power producers that have some long-term contracts in place.[79] As we have done in previous studies, we make an upward adjustment towards the upper end of the range from the comparable company results to reflect the relatively higher risk of merchant operations. Based on the set of reference points shown in Table 17 and Figure 7 above and the recognition of PJM merchant generation risk that exceeds the average risk of the publicly-traded generation companies, we believe that, under the 35% federal tax rate, a 7.0% ATWACC is the most reasonable estimate for the purpose of estimating CONE.[80] Our recommended 7.0% is above our own cost of capital estimates for the merchant companies and is at the high end of the range of discount rates disclosed in the fairness opinions.

Reduction in Federal Corporate Income Tax Rate and Cost of Capital: After we completed the above ATWACC analysis in early November 2017, the Tax Cuts and Jobs Act was passed in the U.S. Congress on December 22, 2017. More than three decades after the Tax Reform Act of 1986, the new tax law brings fundamental changes to the U.S. tax system including a substantial reduction in the federal income tax rate, a transition from worldwide tax to territorial tax, and immediate expensing of qualified investments. It is inevitable that businesses and individuals will adjust their investment, consumption, and financing decisions as a result of these changes in the tax code.[81] Given the complexity of the new tax law, the interpretation and implementation will not happen immediately, but take time to be fully incorporated in personal and corporate decisions. Moreover, the behaviors of economic agents will change over time. All of these imply that the impact of the new tax law on PJM merchant generating plants' cost of capital beyond 2022 is complex and will not be fully known until several years from now.

Nonetheless, we need to develop the PJM CONE values now, well ahead of the time when the impacts of the tax changes on project cost of capital can be measured empirically. ATWACC is a key input to the CONE calculation. Since the estimation of ATWACC depends on investment's capital structure, and a firm's COE and COD depend on the capital structure, we focus our investigation on how the impact of the tax rate reduction may affect the capital structure of investments. Conceptually, a decrease in the federal corporate income tax rate reduces the tax advantage of debt relative to equity. One would thus expect investors to choose a higher equity ratio under the lower tax rate. Combined with a higher after-tax cost of debt, ATWACC will thus increase. Empirically, is this prediction correct, and if so, how much will the capital structure adjust? To answer this question, we turn to the economic literature examining capital

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

80 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.

81 The new tax law lowers tax rates and elimination exception at the individual level. These too can have an impact on the capital structure.

structure decisions in response to prior changes in tax rates as "natural experiments,"[82] such as the federal corporate income tax rate reduction in the 1986 tax act (from 46% in 1986 to 34% in 1988), and numerous corporate income tax changes (both increases and decreases) at the state level.[83]

Researchers have made progress, both theoretically and empirically, in isolating the impact of tax rate changes on capital structure from U.S. historical experience.[84] The earliest research focused on the impact of a single event, the Tax Reform Act of 1986, on capital structure. According to the static "trade-off model" of capital structure, as illustrated in Figure 8, the optimal debt level is the point at which the marginal benefit of the interest tax shield (the flat line) equals the marginal cost of financial distress (the upward-sloping line).[85] Under this theory, the federal corporate tax rate reduction in the 1986 act should have led to a noticeable reduction in financial leverage, shown as a parallel shift downward of the marginal benefit line and a reduction in the optimal debt (D′<D).[86] However, as reported by Gordon and MacKie-Mason (1990), "the actual change in debt-to-value ratios has been substantially smaller than the models predict."[87] More recent papers examine tax law changes over a much longer period. For example, Graham, Leary, and Roberts (2015) investigate determinants of the century-long capital structure of U.S. publicly-traded companies, and conclude "corporate taxes underwent 30 revisions over the past century and increased from 10% to 52% between 1920 and 1950. Yet we find no significant time-series relation between taxes and the margin between debt usage and common equity."[88] Similarly, DeAngelo and Roll (2015) present time series evidence on the capital structure of 24

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82 These legislative decisions are quasi-experimental because they are largely out of the firms' control. Under these circumstances, researchers can more reliably infer the causal, instead of purely statistical, impact of tax rate changes on capital structure.

83 The basic premise behind our ATWACC approach that cost of capital is largely constant over a large range of capital structure is based on far larger empirical papers examining whether interest deduction affects capital structure using the cross-sectional evidence of firms' capital structure decisions. Tax rates are constant across firms and years in this literature.

84 There are also collaborations using international evidence. We limit our review to the U.S.

85 See, *e.g.*, Richard Brealey, Stewart C. Myers, and Franklin Allen (2011), *Principles of Corporate Finance*. New York: McGraw-Hill/Irwin (Chapter 18).

86 A complete analysis should incorporate the changes in personal taxes. In the case of 1986 tax act, the combined impact is to increase the tax advantage of debt. See Roger H. Gordon, and Jefrrey MacKie-Mason, 1990, "Effects of the Tax Reform Act on Corporate Financial Policy and Organization Form," NBER Working Paper No. 3222, at p. 7.

87 *Ibid.*, at p. 2. Their theoretical model suggests a 15.5% increase in debt/value ratio, but the observed increase was only 4.1% (at p. 16).

88 John R. Graham, Mark T. Leary, and Michael R. Roberts, 2015, "A Century of Capital Structure: The Leveraging of Corporate America," *Journal of Financial Economics* (118), 658–683.

Dow Jones Industrial Average (DJIA) companies over the last century.[89] None of the changes in capital structure are related to the tax reform act of 1986, and around 1986, DJIA companies' capital structure moved in different directions.

The empirical research above assumes a linear relationship between tax rates and debt ratios. Recent development in *dynamic* trade-off models,[90] however, predicts an asymmetric non-linear relationship: the debt ratios respond positively to tax rate increases, but do not react to tax rate reductions. Intuitively, a rise in the tax rate will increase the tax benefit of financial leverage, and incentivize the shareholders to borrow more. With a decrease in the tax rate, however, reducing borrowing will lower shareholders' option to default: this will benefit bond holders at shareholders' expense. Thus, shareholders have no incentive to reduce debt in the case of a tax rate reduction (D'=D in Figure 8b).[91] Heider and Ljungqvist (2015) confirm such an asymmetric relationship.[92] In their paper, the authors compile a large sample of 121 state-level tax rate increases or decreases between 1989 and 2011. The large sample of tax rate changes in multiple states over a long period of time allows the authors to design multiple empirical tests to confirm that their finding of an asymmetric impact of tax rates is robust and statistically significant.

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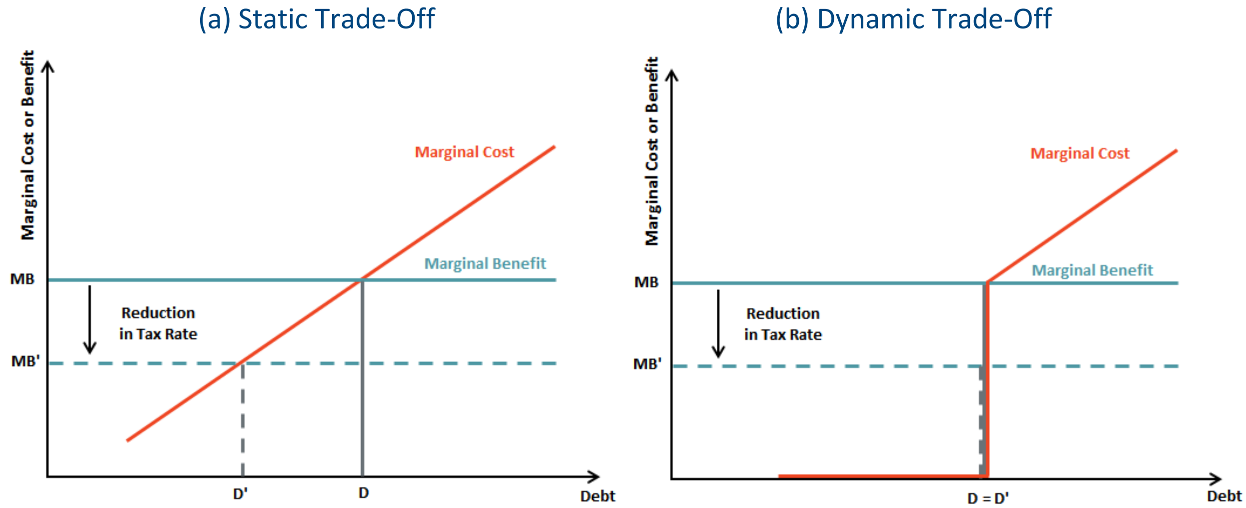
89 Harry DeAngelo, and Richard Roll, 2015, "How stable are corporate capital structures?," *Journal of Finance* (70), 373-418.

90 See, *e.g.*, Anat R. Admati, Peter M. DeMarzo, Martin F. Hellwig, Paul Pfleiderer, 2017, "The Leverage Ratchet Effect," forthcoming in *Journal of Finance*; and Christopher A. Hennessy, Akitada Kasahara, and Ilya A. Strebulaev, 2016, "Corporate Finance Responses to Exogenous Tax Changes: What Is the Null and Where Did It Come From?," Stanford University Working paper.

91 For example, Admati, *et al.*, *op cit.*, at p. 1 state "Once debt is in place, shareholders will resist any form of leverage reduction no matter how much the leverage reduction may increase total firm value. At the same time, shareholders would generally choose to increase leverage even if any new debt must be junior to existing debt. The resistance to leverage reductions, together with the desire to increase leverage, creates asymmetric forces in leverage adjustments that we call *the leverage ratchet effect*."

92 Florian Heider, and Alexander Ljungqvist, 2015, "As Certain as Debt and Taxes: Estimating the Tax Sensitivity of Leverage from State Tax Changes," *Journal of Financial Economics* (118), 684–712.

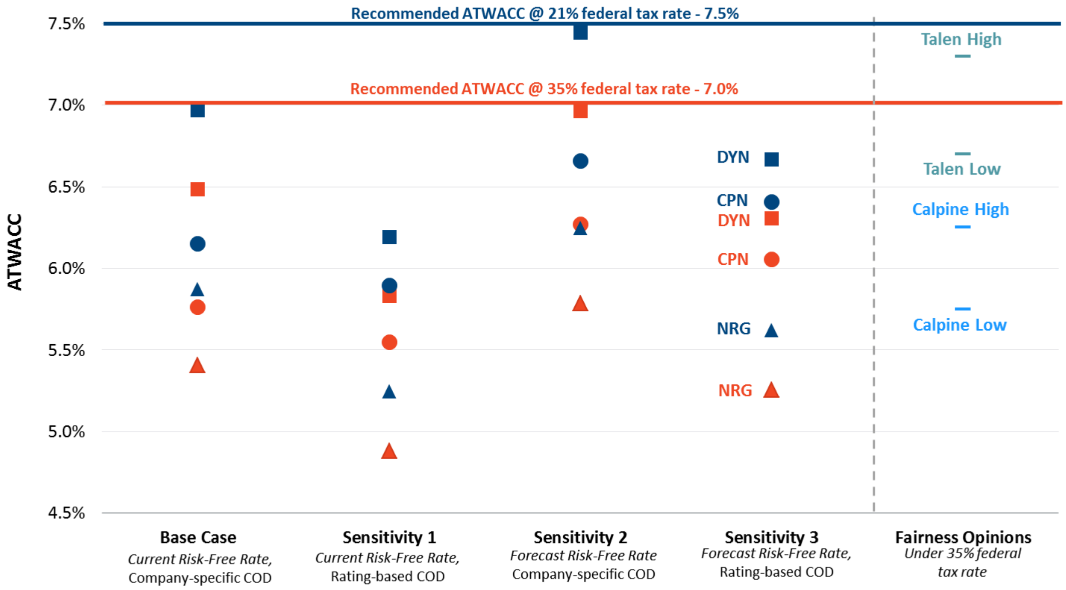
Figure 8: Illustrate Dynamic Trade-off of Tax Benefit and Cost



This research suggests that a decrease in the federal tax rate will *not* have a material impact on capital structure. As a result, we recommend retaining the components of ATWACC, *i.e.*, ROE, COD, and debt and equity ratios, based on our November 2017 analysis.[93] Figure 9 presents both the ATWACCs under the 35% and 21% federal tax rates. The blue marks represent ATWACCs of the U.S. IPPs under the 21% tax rate. The marginal impact of a lower federal tax rate increases cost of capital between 0.4% and 0.6%, which makes us increase the recommended ATWACC from 7.0% to 7.5% to reflect the impact of the reduced corporate tax rate as shown by the blue line in Figure 9.

93 We have verified that the sample companies' beta (based on five-year's historical data) and cost of debt stay more or less constant since November 2017.

Figure 9: ATWACCs of U.S. IPPs and Discount Rates from Fairness Opinions (35% and 21% Federal Tax Rate)



Note: Blue and red denote ATWACC estimates using federal corporate tax rates of 21% and 35%, respectively.

B. Other Financial Assumptions

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

Inflation rates affect our CONE estimates by forming the basis for projected increases in various fixed O&M cost components over time. We calculated the 20-year inflation rate for four years from now implied by the Cleveland Federal Reserve's estimates of inflation of 2.2%.[94] The most forward looking forecast in the Blue Chip Economic Indicators report is 2.3%.[95] Based on these sources, we assumed for the CONE calculations an average long-term inflation rate of 2.2%.

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. We use a marginal federal corporate income tax rate of 21% as explained in the previous section due to the

94 As stated on the Cleveland Federal Reserve website, the Cleveland Fed's "inflation expectations model uses Treasury yields, inflation data, inflation swaps, and survey-based measures of inflation expectations to calculate the expected inflation rate (CPI) over the next 30 years." Federal Reserve Bank of Cleveland (2017), *Cleveland Fed Estimates of Inflation Expectations*, accessed November 11, 2017. Available at https://www.clevelandfed.org/our-research/indicators-and-data/inflation-expectations.aspx.

95 Blue Chip Economic Indicators (2017), *Blue Chip Economic Indicators, Top Analysts' Forecasts of the U.S. Economic Outlook for the Year Ahead*, New York: Aspen Publishers, October 2017. We used the consensus ten-year average consumer price index (CPI) for all urban consumers.

passing of the Tax Cuts and Jobs Act. The state tax rates assumed for each CONE Area are shown in Table 18.

Table 18: State Corporate Income Tax Rates

CONE Area	Representative State	Corporate Income Tax Rate	Sales Tax Rate
1 Eastern MAAC	New Jersey	9.00%	6.63%
2 Southwest MAAC	Maryland	8.25%	6.00%
3 Rest of RTO	Pennsylvania	9.99%	6.34%
4 Western MAAC	Pennsylvania	9.99%	6.34%

Sources and notes:
State tax rates retrieved from www.taxfoundation.org

We calculated depreciation for the 2022/23 CONE parameter based on the bonus depreciation provisions of the 2017 Tax Cuts and Jobs Act. New units put in service before January 1, 2023 can apply 100% bonus depreciation in the first year of service, which decreases CT CONE on average by $11,700/MW-year and CC CONE on average by $14,400/MW-year. The bonus depreciation then phases out over five years, decreasing by 20% in each subsequent year such that plants in service before January 1, 2024 can utilize 80% bonus depreciation. For calculating depreciation for the 2023/24 auctions and later auctions, we apply the Modified Accelerated Cost Recovery System (MACRS) of 20 years for a CC plant and 15 years for a CT plant to the remaining depreciable costs (*i.e.*, 80% bonus depreciation, 20% MACRS in 2023/24).[96]

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 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.*, 60% debt and 7.0% COD.

[96] Internal Revenue Service (2013), *Publication 946, How to Depreciate Property,* February 15, 2013. Available at http://www.irs.gov/pub/irs-pdf/p946.pdf.

VII. CONE Estimates

Translating investment costs into annualized costs for the purpose of setting annual capacity prices requires an assumption about how net revenues are received over time to recover capital and annual fixed costs. "Level-nominal" cost recovery assumes that net revenues will be constant in nominal terms (*i.e.*, decreasing in real, inflation-adjusted dollar terms) over the 20-year economic life of the plant. A "level-real" cost recovery path starts lower in the first year (by about 16%) then increases at the rate of inflation (*i.e.*, is constant in real dollar terms).[97]

While there is no perfect way to capture developers' expectations for their future cost recovery paths, we previously reviewed long-term trends in plant costs and efficiency to understand the likely long-term drivers of new entry offers and whether a developer would expect that market revenues would lead to a more front-loaded or more back-loaded recovery of investment costs. This section of our report first re-visits the analysis of whether a level-nominal or level-real annualization approach is more consistent with market data and then presents the summary of CONE estimates by CONE Area.

A. Levelization Approach

In the 2011 PJM VRR Report, we analyzed the historical trends of turbine costs and heat rates to inform the potential of the cost recovery path for a new gas-fired generation resource. We found that over the previous 20 years combustion turbine costs increased on average by 0.6% per year faster than inflation and that the average heat rates of new gas-fired CTs decreased by approximately 100 Btu/kWh a year.[98] Based on this analysis, we found it likely that the net revenues for the marginal resources in the PJM capacity market would tend to increase approximately with inflation over time. We consequently recommended that PJM adopt a *level-real* cost recovery for calculating CONE to reflect these findings. We maintained this recommendation in the 2014 VRR Report.

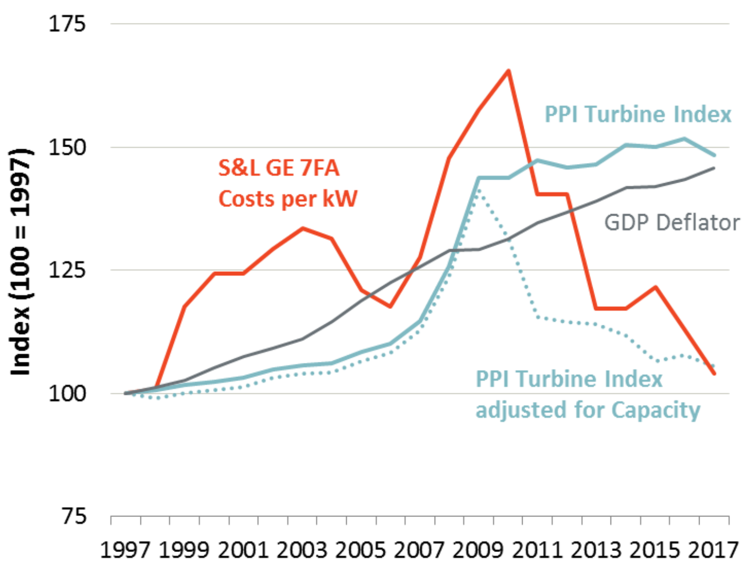
Updating this analysis based on the latest data available we come to superficially similar results: over the most recent 20-year period, the turbine cost indices that we relied on in 2011 escalated on average at 0.9% per year faster than inflation and the heat rate of CTs decreased by approximately 100 Btu/kWh on average. However, the turbine cost indices do not properly account for the significant increase in net plant output for F-class turbines (+42% since 2010 as discussed in Section II.B above) that have been installed in PJM most recently. Based on S&L cost estimates for over the past 20 years, the costs of GE 7FA turbines have declined by 37% on a per-kW basis since 2010, as shown by the red line in Figure 10 below. By comparison, the

97 Both cost recovery paths (level-real and level-nominal) are calculated such that the NPV of the project is zero over the 20-year economic life.

98 See The Brattle Group "Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM," August 24, 2011.

Producer Price Index (PPI) turbine cost index increased by 3% since 2010 (as shown by the solid teal line). While the PPI Turbine index shows a similar trend over the first thirteen years as the S&L estimates, the cost trends diverge once the net output of the F-class turbine starts increasing around 2010. To account for this recent change in turbine output, we adjusted the PPI Turbine index for the increases in plant capacity (shown as the dotted teal line) and observe that the adjusted index follows a similar trend to the GE 7FA costs over this period.[99] Our analysis shows that the assumption that costs per kW will continue to escalate slightly faster than inflation in the long-term may no longer apply. In fact, both the S&L GE 7FA cost per kW trend and the capacity-size adjusted PPI Turbine Index show that 2017 turbine costs are only slightly more expensive on a nominal $/kW basis than 20 years ago.

Figure 10: Gas Combustion Turbine Cost Trends since 1997



Sources and notes:
S&L cost estimates; BLS PPI Turbine & Turbine Generator Sets; Gas Turbine World.

Looking forward, there is no perfect way to project how cost trends will unfold and how gas-fired units expect to recover their costs.[100] In addition to the considerations analyzed above, developers of new generation resources must consider that the gas generation technologies are likely to continue to see periodic incremental improvements over time, similar to the downward

99 We would not expect the GE 7FA index and adjusted PPI turbine index to perfectly align as the PPI includes a much wider range of turbine types. The BLS methodology for developing the PPIs mentions that in most cases the indices include a "quality adjustment" to account for such changes in product quality as seen here. However, this does not appear to be the case for the PPI turbine index based on our attempt at benchmarking the index against historical cost estimates for GE 7FA turbines.

100 As stated in our 2014 VRR Curve report, "one could make a case for attempting to determine projections of net revenues representing actual developers' likely views on energy prices, fuel prices, and capacity prices over the 20-year investment life. The entirety of this information is what ultimately determined the 'true' value of CONE." See 2014 VRR Curve Report, p. 11.

cost trend since 2010. Investors in new generating resources have to consider the possibility that their future net revenues may erode as technological innovation and environmental policies favor different types of technologies, such as renewable generation combined with storage.

Due to the lower escalation rate of gas turbine plants in $/kW terms than previously estimated and the potential for similar cost-reductions to arrive periodically over the 20-year economic life of new natural gas-fired generating plants, we recommend adopting the *level-nominal* approach for setting the 2022/23 CONE value.

B. Summary of CONE Estimates

Table 19 and Table 20 show summaries of our plant capital costs, annual fixed costs, and levelized CONE estimates for the CT and CC reference plants for the 2022/23 delivery year. For comparison, the tables include the most recent 2021/22 PJM administrative CONE parameters escalated to a 2022/23 delivery year at 2.8% per year.

For the CT, the level-nominal CONE estimates range from $98,200/MW-year in the Rest of RTO to a high of $108,400/MW-year in SWMAAC. The updated estimates are lower than the previous parameters escalated to 2022/23 by 22–28% due to a decrease in capital costs and a lower ATWACC offset. Capital costs are lower primarily due to the lower tax rates, the change in turbine to the larger H-class turbine, and the change to a 1×0 configuration (reducing labor and equipment and materials costs. In addition, the reduction in ATWACC from 8.0% to 7.5% reduces CONE values by an average of 3.8%.

Table 19: Recommended CONE for CT Plants in 2022/2023

				Simple Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$316	$297	$257	$305
[2]	Installed (inc. IDC)	*$m*		$330	$310	$268	$318
[3]	First Year FOM	*$m/yr*		$5	$9	$6	$4
[4]	**Net Summer ICAP**	***MW***		**352**	**355**	**321**	**344**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$898	$836	$799	$886
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$938	$874	$835	$925
[7]	Levelized FOM	*$/kW-yr*	= [3] / [4]	$16	$24	$18	$15
[8]	**After-Tax WACC**	***%***		**7.4%**	**7.5%**	**7.4%**	**7.4%**
[9]	Effective Charge Rate	*%*		10.1%	10.1%	10.0%	10.0%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$106,400**	**$108,400**	**$98,200**	**$103,800**
	Prior Auction CONE						
[11]	PJM 2021/22 CONE	*$/MW-yr*		$133,144	$140,953	$133,016	$134,124
[12]	Escalated to 2022/23	*$/MW-yr*	= [11] x 1.028	$136,900	$144,900	$136,700	$137,900
	Difference between Updated CONE and Escalated Prior Auction CONE						
[13]	Escalated to 2022/23	*$/MW-yr*	= [10] - [12]	($30,400)	($36,500)	($38,600)	($34,000)
[14]	Escalated to 2022/23	*%*	= [13] / [12]	-22%	-25%	-28%	-25%

Sources and notes:

PJM 2021/22 parameters escalated to 2022/23 at 2.8% annually, based on S&L analysis of escalation rates for materials, turbine and labor costs.

CONE values expressed in 2022 dollars and ICAP terms.

The CT CONE estimates vary by CONE Area primarily due to differences in emissions controls technologies (no SCR in the Rest of RTO), labor rates (highest in EMAAC), and property taxes (highest in SWMAAC). The Rest of RTO is at the low end due to the change in specification for the CT in this CONE Area that no longer includes an SCR. EMAAC CONE ($106,400/MW-year) is closer in value to SWMAAC at the high end of the range despite significantly higher capital costs, but lower annual property taxes. The WMAAC CONE is lower than EMAAC primarily due to slightly lower labor costs.

For the CC, the level-nominal CONE estimates range from $109,800/MW-year in the Rest of RTO to $120,200/MW-year in SWMAAC. The updated estimates are 40–41% lower than the previous estimates escalated to 2022/23 primarily due to the economies of scale of the larger H-class turbines and the lower tax rates. Similar to the CT, the decrease in ATWACC further reduces the CONE by an additional 3.8%.

Table 20: Recommended CONE for CC Plants in 2022/2023

				Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,006	$896	$928	$961
[2]	Installed (inc. IDC)	*$m*		$1,095	$976	$1,009	$1,046
[3]	First Year FOM	*$m/yr*		$23	$43	$25	$21
[4]	**Net Summer ICAP**	***MW***		**1,152**	**1,160**	**1,138**	**1,126**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$873	$772	$815	$853
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$951	$841	$887	$929
[7]	Levelized FOM	*$/kW-yr*	= [3] / [4]	$24	$38	$24	$22
[8]	**After-Tax WACC**	***%***		**7.4%**	**7.5%**	**7.4%**	**7.4%**
[9]	Effective Charge Rate	*%*		10.6%	10.6%	10.5%	10.5%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$116,000**	**$120,200**	**$109,800**	**$111,800**
	Prior Auction CONE						
[11]	PJM 2021/22 CONE	*$/MW-yr*		$186,807	$193,562	$178,958	$185,418
[12]	Escalated to 2022/23	*$/MW-yr*	= [11] x 1.028	$192,000	$199,000	$184,000	$190,600
	Difference between Updated CONE and Escalated Prior Auction CONE						
[13]	Escalated to 2022/23	*$/MW-yr*	= [10] - [12]	($76,000)	($78,800)	($74,200)	($78,800)
[14]	Escalated to 2022/23	*%*	= [13] / [12]	-40%	-40%	-40%	-41%

Sources and notes:

PJM 2021/22 parameters escalated to 2022/23 at 2.8% annually, based on S&L analysis of escalation rates for materials, turbine and labor costs.

CONE values expressed in 2022 dollars and ICAP terms.

Differences in the CC CONE estimates across the CONE Areas are primarily due to differences in labor with the highest labor costs in EMAAC and lowest in Rest of RTO. Despite similar labor costs in SWMAAC compared to Rest of RTO, the SWMAAC CONE is greater than EMAAC due to its higher fixed O&M costs, as a result of higher property taxes, and the higher costs of the firm gas contracts (assumed necessary in SWMAAC) compared to the combination of non-firm gas contracts and dual fuel capability (assumed to be sufficient in EMAAC).

The updated CC CONE values have decreased significantly more over the prior estimates than the CT CONE values have, leading to a narrower cost premium for CCs of $8,000–11,800/MW-year compared to the $46,000–54,000/MW-year premium in the 2020/21 BRA parameters. The most significant driver narrowing the difference between CT and CC CONE is economies of scale with the very large CC based on the 7HA. While the capacity of the CCs plants has almost *doubled* compared to that in the 2014 CONE Study, the cost of the gas turbines increased by 50%, and the cost of the steam section of the CC (including the heat recovery steam generator and steam turbine) increased by only 30%. CT plants share the same economies of scale on the combustion turbine itself, but not the greater economies of scale the CCs enjoy on their steam section or other balance of plant costs. In the Rest of RTO CONE Area, the lack of the SCR on the CT results in an increased CC premium.

VIII. Annual CONE Updates

PJM's tariff specifies that CONE will be escalated annually 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 21 below, we recommend that PJM weight the components in the CT composite index based on 20% labor, 55% materials (increased from 50%), and 25% turbine (decreased from 30%). We recommend that PJM weight the CC components based on 30% labor (increased from 25%), 50% materials (decreased from 60%), and 20% turbine (increased from 15%).

Table 21: CONE Annual Update Composite Index

	Simple Cycle			Combined Cycle		
	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%	22%	20%	25%	30%	30%
Materials	50%	53%	55%	60%	52%	50%
Turbines	30%	26%	25%	15%	18%	20%

Sources and notes:
Values may not add up to 100% due to rounding.

PJM will need to account for bonus depreciation declining by 20% in subsequent years starting in 2023. We calculate that a reduction in the bonus depreciation by 20% increases the CT CONE by 2.2% and the CC CONE by 2.5% due to the decreasing depreciation tax shield. We recommend that after PJM has escalated CONE by the composite index, as noted above, PJM account for the declining tax advantages of decreased bonus depreciation by applying an additional gross up of 1.022 for CT and 1.025 for CCs.

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: Detailed Technical Specification Analysis

A. Combined Cycle Cooling System

For the reference CC plant, we assumed a closed-loop circulating water cooling system with a multiple-cell mechanical draft cooling tower, based on the predominance of cooling towers among new CCs and S&L recommendation.

Our review of EIA-860 data found that a majority of CC plants with a specified cooling system had a cooling tower installed, as shown in Table 22.

Table 22: Cooling System for CC Plants in PJM Built or Under Construction Since 2014

State	Once-Through *(MW)*	Cooling Tower *(MW)*	Dry Cooling *(MW)*
Delaware	0	309	0
Illinois	0	573	0
Indiana	0	642	0
Maryland	0	1,726	800
New Jersey	0	2,962	0
Ohio	0	2,173	683
Pennsylvania	1,064	4,314	3,905
Virginia	0	2,455	2,629
Total	**1,064**	**15,154**	**8,017**

Sources and notes:
Based on 2015 Form EIA-860 Data; cooling tower includes recirculating with forced, induced, and natural cooling towers.

We reviewed whether reclaimed water from municipal waste treatment centers would be available for use in the cooling systems to avoid environmental issues with withdrawing fresh water. Our review of the availability of reclaimed water indicated that EMAAC has at least two recently developed generating facilities that utilize reclaimed water. Previous research indicated that EMAAC has at least one waste water treatment facility per county, such that reclaimed water can be considered generally available. In Rest of RTO, we found one facility that utilized reclaimed water but did not find this is a predominant trend in the area. For SWMACC and WMAAC, municipal waste treatment facilities are much less common such that withdrawals from ground or surface water would be necessary. Our research did not identify any recently developed generating facilities that utilized reclaimed water in either CONE Area. In addition to environmental drivers for using reclaimed water, building the piping and treatment facilities required for ground or surface water costs \$500k to \$1 million more than for reclaimed water, depending on the location.

B. Power Augmentation

Evaporative coolers are included downstream of the filtration system to lower the combustion turbine inlet air temperature during warm weather operation. With a few exceptions the use of evaporative coolers has become a standard in industry practice where water is available. The use of evaporative coolers increases turbine output and efficiency for a small increase in capital cost. In addition, the combustion turbines in both simple- and combined-cycle arrangements are equipped with an inlet filtration system to protect from airborne dirt and particles. Evaporative coolers and associated equipment add $3 million per combustion turbine to the capital costs.

C. Black Start Capability

Based on our analysis in the 2011 PJM CONE Study, we did not include black start capability in either the CC or CT reference units because few recently built gas units have this capability.

D. Electrical Interconnection

While all CONE Areas have a variety of transmission voltages, both lower and higher than 345 kV, we selected 345 kV as the typical voltage for new CT and CC plants to interconnect to the transmission grid in PJM. The switchyard is assumed to be within the plant boundary and is counted as an EPC cost under "Other Equipment," including generator circuit breakers, main power and auxiliary generator step-up transformers, and switchgear. All other electric interconnection equipment, including generator lead and network upgrades, is included separately under Owner's Costs, as presented in Section IV.C.4.

E. Gas Compression

Similar to the 2014 PJM CONE Study, we assume gas compression would not be needed for new gas plants with frame-type combustion turbines located near and/or along the major gas pipelines selected in our study. The frame machines generally operate at lower gas pressures than the gas pipelines.

Appendix B: Detailed Cost Estimate Assumptions

A. 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 2017. 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 work week with per-diem included to attract skilled labor.

Labor rates have been updated since the 2014 CONE study to represent the current competitive market. Additionally, 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. As a result, the labor rates in this CONE study are lower than those in the 2014 CONE study by approximately 5% for CTs and 6% for CCs on average.

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 were used in the 2014 PJM CONE Study and are in-line with recent projects in which S&L has been involved.

A summary of construction labor cost assumptions is shown below in Table 23.

Table 23: Construction Labor Cost Assumptions

		EMAAC	SWMAAC	Rest of RTO	WMAAC
CT Plant					
2017 Construction Labor Hours	*hours*	260,918	238,253	225,598	258,762
2017 Weighted Average Crew Rates	*$*	119.54	91.59	96.46	102.89
2017 Productivity Factor	--	1.18	1.10	1.12	1.17
2017 Construction Labor Costs	*$*	$36,729,452	$26,839,467	$26,229,993	$31,795,172
2017 Construction Labor Costs	*$/kW*	104	76	82	92
CC Plant					
2017 Construction Labor Hours	*hours*	1,240,716	1,148,990	1,179,563	1,230,523
2017 Weighted Average Crew Rates	*$*	125.85	100.39	103.05	111.38
2017 Productivity Factor	--	1.18	1.10	1.12	1.17
2017 Construction Labor Costs	*$*	$182,316,769	$137,591,371	$144,572,598	$161,654,881
2017 Construction Labor Costs	*$/kW*	158	119	127	144

B. 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 10/10/2017 to estimate 2022 gas prices.
- **Fuel Oil**: rely on No. 2 fuel oil futures for New York harbor through January 2021; escalate fuel oil prices between January 2021 and an assumed fuel delivery date of May 2022 based on the escalation in Brent crude oil futures over the same date range.
- **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;[101] 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.

Table 24: 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	Fuel Oil Use	Fuel Oil Price	Fuel Oil Cost	Total Cost
	(MWh)	*($/MWh)*	*($m)*	*(MMBtu)*	*($/MMBtu)*	*($m)*	*(MMBtu)*	*($/MMBtu)*	*($m)*	*($m)*
Gas CT										
1 Eastern MAAC	186,984	$22.51	$4.21	1,627,295	$3.57	$5.8	81,365	$12.63	$1.03	$2.6
2 Southwest MAAC	187,992	$27.89	$5.24	1,635,888	$3.60	$5.9	81,365	$12.63	$1.03	$1.7
3 Rest of RTO	165,816	$27.42	$4.55	1,439,915	$2.59	$3.7	81,365	$12.63	$1.03	$0.2
4 Western MAAC	180,936	$23.20	$4.20	1,575,694	$2.40	$3.8	81,365	$12.63	$1.03	$0.6
Gas CC										
1 Eastern MAAC	1,081,584	$22.51	$24.34	6,458,602	$3.57	$23.0	162,730	$12.63	$2.06	$0.7
2 Southwest MAAC	1,036,800	$27.89	$28.92	6,499,699	$3.60	$23.4	--	$12.63	$0.00	-$5.5
3 Rest of RTO	1,056,384	$27.42	$28.96	6,306,109	$2.59	$16.4	162,730	$12.63	$2.06	-$10.5
4 Western MAAC	1,048,320	$23.20	$24.32	6,256,973	$2.40	$15.0	162,730	$12.63	$2.06	-$7.2

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 10/10/2017.

C. Gas and Electric Interconnection Costs

Similar to the 2014 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

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

costs. We escalated the project-specific costs to 2017 dollars based on the assumed long-term inflation rate of 2.4% (see Table 12 above). We then calculated the average per-mile costs of the laterals ($4.6 million/mile) and the station costs ($3.4 million). The summary of project costs and the average per-mile pipeline cost and metering station cost are shown in Table 25.[102]

Table 25: Gas Interconnection Costs

Gas Lateral Project	State	In-Service Year	Pipeline Width *(inches)*	Pipeline Length *(miles)*	Pipeline Cost *(service year $m)*	Pipeline Cost *(2017$m)*	Pipeline Cost *($m/mile)*	Meter Station *(Y/N)*	Station Cost *(service year $m)*	Station Cost *(2017$m)*
Delta Lateral Project	PA	2010	16	3.4	$9	$11	$3	Y	$3.3	$3.8
FGT Mobile Bay Lateral Expansion	AL	2011	24	8.8	$27	$31	$4	Y	$2.4	$2.8
Northeastern Tennessee Project	VA	2011	24	28.1	$127	$147	$5	Y	$2.8	$3.2
Hot Spring Lateral Project	TX,AR	2011	16	8.4	$33	$38	$4	Y	$3.6	$4.2
Bayonne Delivery Lateral Project	NJ	2012	20	6.2	$13	$15	$2	Y	$3.8	$4.3
North Seattle Delivery Lateral Expansion	WA	2012	20	2.2	$11	$13	$6	Y	$1.4	$1.6
South Seattle Delivery Lateral Expansion	WA	2013	16	4.0	$14	$15	$4	N	n.a.	n.a.
Carty Lateral Project	OR	2015	20	24.3	$52	$55	$2	Y	$2.3	$2.4
Woodbridge lateral	NJ	2015	20	2.4	$29	$30	$13	Y	$3.5	$3.6
Western Kentucky Lateral Project	KY	2016	24	22.5	$71	$73	$3	Y	$4.8	$4.9
Rock Springs Expansion	PA,MD	2016	20	11.17	$41	$42	$4	Y	$3.3	$3.3
Average							**$4.6**			**$3.4**

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 26 below summarizes the average electrical interconnection costs of recently installed gas-fired resources that we identified as representative of the CT and 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 2017 dollars based on the assumed long-term inflation rate of 2.2% plus the additional real escalation rate for equipment of 0.2%. We then calculated the capacity-weighted average costs. We used the capacity-weighted average across all representative plants of $19.9/kW for setting the electrical interconnection of the CT and CC reference resources.

102 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 26: Electric Interconnection Costs in PJM

Plant Size	Observations	Electrical Interconnection Cost Capacity Weighted Average	
	(count)	*(2017\$m)*	*(2017\$/kW)*
< 500 MW	3	\$4.5	\$16.6
500-750 MW	4	\$9.8	\$14.5
> 750 MW	5	\$29.7	\$23.4
Capacity Weighted Average	**12**	**\$21.1**	**\$19.9**

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

D. 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 27.

Table 27: Current Land Asking Prices

CONE Area	Current Asking Prices		
	Observations *(count)*	Range *(2018\$/acre)*	Land Price *(2018\$/acre)*
1 EMAAC	6	\$21,500 - \$49,000	\$36,300
2 SWMAAC	3	\$58,400 - \$95,100	\$66,700
3 RTO	7	\$6,100 - \$60,300	\$26,200
4 WMAAC	2	\$25,000 - \$63,600	\$51,100

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

E. Property Taxes

Table 28 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 28: 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]
		(%)	*(%)*	*(%)*	*(%)*	*(%)*	*(%)*	
1 EMAAC								
New Jersey	[1]	3.8%	97.8%	3.7%	n/a	n/a	n/a	n/a
2 SWMAAC								
Maryland	[2]	1.1%	100.0%	1.1%	2.8%	50.0%	1.4%	3.3%
3 RTO								
Ohio	[3]	5.8%	35.0%	2.0%	5.8%	24.0%	1.4%	Follow annual report "SchC-NewProd (NG)"
Pennsylvania	[4]	2.5%	100.0%	2.5%	n/a	n/a	n/a	n/a
4 WMAAC								
Pennsylvania	[5]	3.6%	99.0%	3.5%	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:
http://www.state.nj.us/treasury/taxation/pdf/lpt/chap123/2017/gloucester.pdf &
http://www.gloucestercountynj.gov/depts/b/botcounty/trb.asp for Camden county see:
http://www.camdencounty.com/service/board-of-taxation/

[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:
http://dat.maryland.gov/Documents/statistics/Taxrate_July2017.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/2016%20Tax%20Rate%20Card.pdf for Carroll county see:
http://www.carrollcountyauditor.us/auditorsadvisory/Rates%20of%20Taxation%202017.pdf

[3b],[3d] Assessment ratios for real property and personal property taxes found on pages 129 and 124:
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:
http://co.lawrence.pa.us/wp-content/uploads/2014/10/2017-Sheet-for-Millage-.pdf

[4b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf
Note: Assessment ratio for calculations is capped at 100%

[4c]-[4e] According to *Pennsylvania Legislator's Municipal Deskbook (taxation & finance)* , 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:
http://www.luzernecounty.org/uploads/images/assets/county/departments_agencies/2017/2017%20Millages.pdf
http://www.lyco.org/Portals/1/TaxClaimBureau/Documents/2017%20Millage%20Rates-JULY%202017.pdf
http://www.bradfordcountypa.org/application/files/1314/9970/7556/2017_Mill_Rates.pdf

[5b] Pennsylvania assessment ratios available at:
http://www.revenue.pa.gov/FormsandPublications/FormsforIndividuals/Documents/Realty%20Transfer%20Tax/clr_factor_current.pdf

[5c]-[5e] According to *Pennsylvania Legislator's Municipal Deskbook (taxation & finance)* , only real estate tax assessed by local governments

F. Firm Gas Contracts

To estimate the costs of acquiring firm transportation service for SWMAAC CCs coming online in 2022, we calculated the average costs of firm gas capacity on a per-kW basis for two recent SWMAAC CCs (St. Charles and Keys Energy Center) based on rates approved by FERC in 2015. We account for the 2022 online date by escalating the reservation rates of $3.7417 per dekatherm for St. Charles and $5.4278 per dekatherm for Keys by 2.4% per year from the online plant years of 2017 (St. Charles) and 2018 (Keys) to 2022. We then calculate the total costs by multiplying the reservation rates by the amount of gas reserved by each facility per month. Next, we calculate the per-kW costs by dividing the total cost of firm gas by the net plant capacity. We calculate the total cost of firm gas reservations for the new reference resource by multiplying the average $/kW value by the net plant capacity for the SWMAAC CC reference resource. Table 29 summarizes the escalated rates and reservation for procuring firm gas service on the DCP pipeline.

Table 29: Estimated Cost of Procuring Firm Gas Service on DCP Pipeline

Component	Units	St. Charles	Keys	Reference Resource
Net Plant Capacity - Max Summer	*(MW)*	726	800	1,031
Cost of Firm Gas Capacity per Month	*(2022$ per Dth/d)*	$4.21	$5.97	$4.96
Total Firm Gas Capacity Reservation	*(Dth/d per year)*	1,584,000	1,284,000	1,952,105
Total Cost of Firm Gas Reservations	*(2022$/kW)*	$9.19	$9.58	$9.39
Total Cost of Firm Gas Reservations	***(2022$)***	**6,673,000**	**7,663,000**	**$9,676,000**

Sources and notes:
153 F.E.R.C. ¶ 61,074 (Issued October 20, 2015).
1 dekatherm (Dth) is equivalent to 1 MMBtu.

G. Operational Startup Parameters

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 30.

Table 30: Recommended Startup Parameters for Reference Resources

		CT		CC	
Parameter	Unit	Current	New	Current	New
ICAP_NOSCR	MW	392	321	n.a.	n.a.
ICAP_SCR	MW	390	348	656	1,012
NOX_RATE_NOSCR	lb/MMBtu	0.0332	0.0332	n.a.	n.a.
NOX_RATE_SCR	lb/MMBtu	0.0074	0.0093	0.0074	0.0074
SO2_RATE	lb/MMBtu	0	0.001	0	0.001
START_MMBTU	MMBtu	146.5	508.5	3,310.8	8,241.4
START_CONSUMED_MWH	MWh	0.4	0.9	10.1	12.6
START_PRODUCED_MWH	MWh	n.a.	n.a.	292.3	1074.7
START_NOX	Lb/Start	28	55	332.71	160

Appendix C: CONE Results with LTSA Costs in Fixed O&M

In the report above, we included hours-based major maintenance costs as variable O&M costs. Since June 2015, long-term major maintenance and overhaul costs that are specified in Long-Term Service Agreements (LTSAs) have been excluded from being counted as variable O&M costs in the PJM cost guidelines for cost offers.[103] We understand these guidelines are being discussed in a current initiative within the Market Implementation Committee. In case the guidelines remain unchanged, we provide a second set of O&M costs and CONE estimates below that include these costs as fixed O&M.

Since major maintenance activities and costs are spaced irregularly over the long-term, the cost in a given year represents an annual accrual for future major maintenance. For hours-based major maintenance, the fixed O&M cost is calculated based on the estimated hours-based costs of major maintenance times the expected operation of the unit in a given year. For a CC, we assume it will operate at 75% capacity factor based on the capacity factors of actual units. For the CT, we assume it will start 240 times per year based on the results of PJM's Peak-Hour Dispatch simulation for estimating the E&AS revenue offset. Removing these costs from variable O&M will increase Net E&AS revenues and offset some (or all) of the increased CONE value in the calculation of Net CONE.

Table 31 and Table 32 below summarize the O&M costs, where the LTSA costs under fixed O&M increased on average by approximately $5.6 million and $10.1 million (in 2022 dollars) for CTs and CCs, respectively.

Table 31: O&M Costs for CT Reference Resource (Alternative O&M Case)

	CONE Area			
O&M Costs	**1 EMAAC** *352 MW*	**2 SWMAAC** *355 MW*	**3 Rest of RTO** *321 MW*	**4 WMAAC** *344 MW*
Fixed O&M (2022$ million)				
LTSA, including Major Maintenance	$5.9	$5.9	$5.9	$5.9
Labor	$1.1	$1.2	$0.8	$0.9
Maintenance and Minor Repairs	$0.5	$0.5	$0.5	$0.5
Administrative and General	$0.2	$0.2	$0.2	$0.2
Asset Management	$0.5	$0.6	$0.4	$0.4
Property Taxes	$0.3	$4.1	$1.8	$0.3
Insurance	$1.9	$1.8	$1.5	$1.8
Working Capital	$0.04	$0.03	$0.03	$0.03
Total Fixed O&M (2022$ million)	**$10.4**	**$14.3**	**$11.2**	**$10.0**
Levelized Fixed O&M (2022$/MW-yr)	**$29,600**	**$40,300**	**$34,900**	**$29,000**
Variable O&M (2022$/MWh)				
Consumables, Waste Disposal, Other VOM	1.10	1.10	0.95	1.10
Total Variable O&M (2022$/MWh)	**1.10**	**1.10**	**0.95**	**1.10**

103 PJM Manual 15: Cost Development Guidelines, p. 44.

Table 32: O&M Costs for CC Reference Resource (Alternative O&M Case)

O&M Costs	CONE Area 1 EMAAC *1152 MW*	 2 SWMAAC *1160 MW*	 3 Rest of RTO *1138 MW*	 4 WMAAC *1126 MW*
Fixed O&M (2022$ million)				
LTSA, including Major Maintenance	$10.7	$10.8	$10.5	$10.4
Labor	$5.8	$6.3	$4.4	$4.6
Maintenance and Minor Repairs	$5.9	$6.1	$5.4	$5.5
Administrative and General	$1.3	$1.4	$1.1	$1.2
Asset Management	$1.6	$1.7	$1.2	$1.3
Property Taxes	$2.0	$12.3	$7.1	$1.9
Insurance	$6.0	$5.4	$5.6	$5.8
Firm Gas Contract	$0.0	$9.7	$0.0	$0.0
Working Capital	$0.1	$0.1	$0.1	$0.1
Total Fixed O&M (2022$ million)	**$33.4**	**$53.8**	**$35.4**	**$30.8**
Levelized Fixed O&M (2022$/MW-yr)	**$29,000**	**$46,400**	**$31,100**	**$27,300**
Variable O&M (2022$/MWh)				
Consumables, Waste Disposal, Other VOM	0.67	0.67	0.67	0.67
Total Variable O&M (2022$/MWh)	**0.67**	**0.67**	**0.67**	**0.67**

Table 33 and Table 34 summarize the CONE estimates where the change in LTSA costs increase CONE on average by $19,000/MW-year for CTs and $10,000/MW-year for CCs due to including the LTSA-related major maintenance costs as fixed O&M. The increase in CONE is greater than the increase in first-year fixed O&M costs (about $16,000/MW-year for CTs and $9,000/MW-year for CCs) due to the "level-nominal" levelization approach described in Section VII.A.[104] The higher CONE is likely to be offset somewhat by increases in Net E&AS revenues in the calculation of Net CONE.

104 Fixed O&M costs generally escalate year-by-year near the assumed inflation rate. The level-nominal approach for calculating CONE converts the rising costs into an annual value that remains constant in nominal terms (does not increase with inflation).

Table 33: Recommended CONE for CTs (Alternative O&M Case)

				Simple Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$316	$297	$257	$305
[2]	Installed (inc. IDC)	*$m*		$330	$310	$268	$318
[3]	First Year FOM	*$m/yr*		$10	$14	$11	$10
[4]	**Net Summer ICAP**	***MW***		**352**	**355**	**321**	**344**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$898	$836	$799	$886
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$938	$874	$835	$925
[7]	Levelized FOM	*$/kW-yr*	= [3] / [4]	$35	$43	$39	$34
[8]	**After-Tax WACC**	***%***		**7.4%**	**7.5%**	**7.4%**	**7.4%**
[9]	Effective Charge Rate	*%*		10.1%	10.1%	10.0%	10.0%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$125,300**	**$127,100**	**$118,800**	**$123,100**
	Prior Auction CONE						
[11]	PJM 2021/22 CONE	*$/MW-yr*		$133,144	$140,953	$133,016	$134,124
[12]	Escalated to 2022/23	*$/MW-yr*	= [11] x 1.028	$136,900	$144,900	$136,700	$137,900
	Difference between Updated CONE and Escalated Prior Auction CONE						
[13]	Escalated to 2022/23	*$/MW-yr*	= [10] - [12]	($11,600)	($17,800)	($17,900)	($14,800)
[14]	Escalated to 2022/23	*%*	= [13] / [12]	-8%	-12%	-13%	-11%

Sources and notes:

PJM 2021/22 parameters escalated to 2022/23 by 2.8%, based on escalation rates for individual cost components.

CONE values expressed in 2022 dollars and ICAP terms.

Table 34: Recommended CONE for CCs (Alternative O&M Case)

				Combined Cycle			
				EMAAC	SWMAAC	Rest of RTO	WMAAC
	Gross Costs						
[1]	Overnight	*$m*		$1,006	$896	$928	$961
[2]	Installed (inc. IDC)	*$m*		$1,095	$976	$1,009	$1,046
[3]	First Year FOM	*$m/yr*		$33	$54	$35	$31
[4]	**Net Summer ICAP**	***MW***		**1,152**	**1,160**	**1,138**	**1,126**
	Unitized Costs						
[5]	Overnight	*$/kW*	= [1] / [4]	$873	$772	$815	$853
[6]	Installed (inc. IDC)	*$/kW*	= [2] / [4]	$951	$841	$887	$929
[7]	Levelized FOM	*$/kW-yr*	= [3] / [4]	$34	$49	$34	$32
[8]	**After-Tax WACC**	***%***		**7.4%**	**7.5%**	**7.4%**	**7.4%**
[9]	Effective Charge Rate	*%*		10.6%	10.6%	10.5%	10.5%
[10]	**Levelized CONE**	***$/MW-yr***	= [5] x [9] + [7]	**$126,400**	**$130,600**	**$120,000**	**$122,100**
	Prior Auction CONE						
[11]	PJM 2021/22 CONE	*$/MW-yr*		$186,807	$193,562	$178,958	$185,418
[12]	Escalated to 2022/23	*$/MW-yr*	= [11] x 1.028	$192,000	$199,000	$184,000	$190,600
	Difference between Updated CONE and Escalated Prior Auction CONE						
[13]	Escalated to 2022/23	*$/MW-yr*	= [10] - [12]	($65,600)	($68,400)	($63,900)	($68,500)
[14]	Escalated to 2022/23	*%*	= [13] / [12]	-34%	-34%	-35%	-36%

Sources and notes:

PJM 2021/22 parameters escalated to 2022/23 by 2.8%, based on escalation rates for individual cost components.

CONE values expressed in 2022 dollars and ICAP terms.

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