PJM Reliability Pricing Model Quadrennial Review: Analysis in Support of The Appropriate Reference Unit

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ENERGYZT

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EXECUTIVE SUMMARY

PJM Reliability Pricing Model Quadrennial Review: Analysis in Support of the Appropriate Reference Unit

The P3 Group commissioned this report as part of a proactive effort to understand the current state of policies, technology, and the characteristics of an appropriate reference unit that would continue to support the existing structure of the Reliability Pricing Model ("RPM") utilized by the PJM Interconnect to procure reliability capacity. The research and analyses described in this report support the following conclusions:

1) **Technological Advances:** Since the last quadrennial review, a number of new technologies are becoming more functionally and commercially viable, in part because of policies set by PJM states that require clean energy generation.

2) **Industry Transformation:** This technological transformation, along with ongoing changes to market rules to support a transition to decarbonization, is establishing a number of generation technologies as viable options in terms of operating characteristics and costs that could be used to set the RPM parameters.

3) **A Combustion Turbine Prevails:** For purposes of this quadrennial review, however, a combustion turbine continues to be the most appropriate reference unit to use for PJM broadly, as it represents a pure-play capacity service offering that does not suffer from significant uncertainty surrounding energy and ancillary services ("E&AS") offsets, and has flexible investment and operating characteristics consistent with a buildout of intermittent renewables.

4) **A Combined Cycle has Flaws:** Choosing a combined cycle, which was recommended but not chosen as the reference unit during the prior quadrennial review, is problematic for a number of reasons, including inconsistency with market dynamics and a greater level of uncertainty around the estimate of Net CONE that cannot and should not be addressed with a steeper demand curve.

5) **A Clean Energy Resource May be Needed:** Going forward, an appropriately configured energy storage resource or other clean energy solution might be a more appropriate reference resource in light of the increasing number of PJM states that are pursuing net zero carbon and 100% renewable goals. Although such alternatives may be required for certain zones, the market would benefit from maintaining the consistency and continuity of a combustion turbine at this time.

The body of this report provides support for these conclusions.

PJM RELIABILITY PRICING MODEL QUADRENNIAL REVIEW: ANALYSIS IN SUPPORT OF THE APPROPRIATE REFERENCE UNIT

Every four years, The PJM Interconnection ("PJM") engages in a quadrennial review regarding a number of decisions pertaining to its centralized capacity market, referred to as the Reliability Pricing Model ("RPM"). RPM is PJM's resource adequacy procurement procedures that create a market-based mechanism with the aim of ensuring long-term resource adequacy through competitive procurement and price signals.[1] Identification of an appropriate reference unit is a key determination of market parameters surrounding the demand curve and the resulting competitive price for capacity. By design and economic theory, the reference unit is supposed to reflect the technology and operating characteristics of a long-term marginal unit of merchant capacity that could be built in PJM broadly, and its designated zones more specifically.

Prior quadrennial reviews limited the debate on which technology should be the reference unit to either: (i) a combustion turbine; or (ii) a combined cycle. Since the last quadrennial review, however, a number of new technologies and different configurations are becoming commercially viable, in part because of political support by states within PJM for cleaner energy generation resources. Such technologies extend beyond renewable resources and batteries to include fossil fuel power generation resources that have greater flexibility, modularity, and ramping capability that can better respond to greater integration of intermittent renewable resources onto the PJM system while mitigating increased market uncertainty. The Cost of New Entry ("CONE") for solar, wind, batteries, aeroderivatives and reciprocating engines are becoming less expensive compared to the traditional entrants of combustion turbines and combined cycles, even without state and federal subsidies.

This report examines the appropriate reference unit for PJM's RPM quadrennial review. The conclusion is that the choice of new entrant, for now, still generally comes down to a combustion turbine versus a combined cycle combustion turbine. Of these, the combustion turbine offers the closest technology to a pureplay capacity provider, as well as the least amount of estimation uncertainty surrounding the Net CONE, for PJM as a whole.[2]

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[1] PJM, https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx

[2] As elaborated upon later in this report, PJM zones in which states have aggressive carbon reduction and renewable energy goals may need to adopt a clean energy alternative to be consistent with permitting and siting limitations. Such alternatives include a solar/battery hybrid, behind-the-meter generation, demand response, and/or the cost of transmission required to ensure reliability to those zones with highly integrated renewable resources plus the RPM reference unit.

Within PJM, there is significant and growing uncertainty surrounding the entry of new technologies, changes to market rules, volatile market prices, and uncertain dispatch projections. Staying with the existing technology of a combustion turbine for a reference unit offers the market constancy and established parameters to meet PJM's reliability reserve requirements over the next four years. Remaining with the combustion turbine as the reference unit also would reduce uncertainty and volatility in RPM prices that face a number of other changes, including PJM's elimination of the Minimum Offer Pricing Rule ("MOPR") and Effective Load Carrying Capability proposals ("ELCC"). By remaining with the combustion turbine, PJM can ensure a more stable price signal for new entry of the caliber needed to ensure reliability instead of compounding the uncertainty by changing reference unit technology.

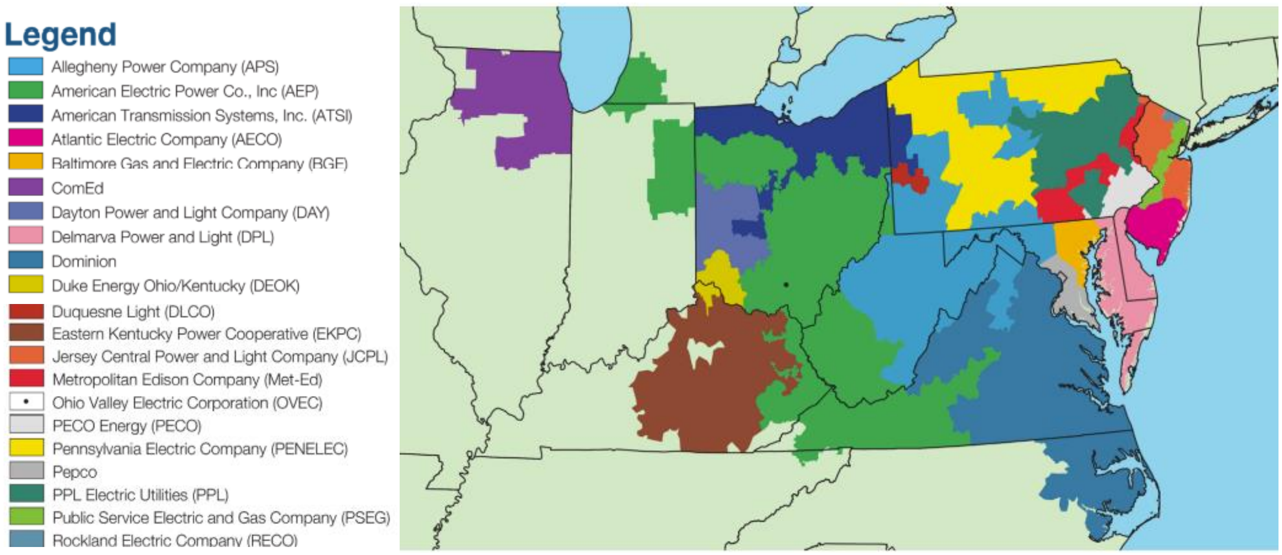
Although the market appears to be at a tipping point with respect to commercialization of new technology, the timing of this quadrennial review arrives in the midst of transition. Whether to adopt a different technology may have a more compelling set of facts at the next quadrennial review as environmental policies and new technology cost curves settle into place.

This report provides the underlying support for these conclusions and is organized as follows. Section 1 describes the current policy preferences of PJM states with respect to the power sector and new generation technology, and implications for the reference unit. Section 2 presents some of the most recent estimates of technology costs in the public domain along with the prices previously adopted by PJM to compare the capital costs for alternative technologies. Section 3 presents support for maintaining a combustion turbine as the appropriate reference unit technology for PJM generally, acknowledging that a more expensive clean energy resource or transmission capacity upgrade may be required for some zones to reflect state policies. Section 4 indicates why a combined cycle introduces needless uncertainty into the reference unit calculation and why a proposal to make the demand curve "steeper" does not resolve these issues and could create barriers to entry and challenges for reliability. Section 5 describes why alternative energy technologies may be more viable candidates for a reference unit during the next quadrennial review. Section 6 summarizes the key conclusions of the analyses described in this report.

1. STATE POLICIES IMPACT PJM'S POWER GENERATION MIX

PJM covers a wide geographical area that includes 21 control areas and 13 states plus the District of Columbia (**Figure 1**). This dispersed system serves 65 million people and has around 180,000 MW of generation capacity across 369,089 square miles of territory.[3]

Figure 1: PJM Footprint and 21 Control Areas[4]



1.1 Multiple states have aggressive renewable and carbon reduction targets

The states that are served by PJM have range of environmental policies. Eleven of these states have passed renewable portfolio standards ("RPS"), with five targeting 100% renewable resources between 2032 and 2050.[5] Nine of the states have aggressive carbon reduction targets with achievement dates as early as 2025 (Illinois, Michigan and Pennsylvania) and 2030 (Delaware, Maryland, North Carolina), with six aiming for total decarbonization of their electric generation by 2050 or before. Three states have stated goals of economy-wide carbon neutrality by 2050, in contrast to the three states that effectively have no environmental policy (**Figure 2**).

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[3] PJM, pjm-at-a-glance.ashx

[4] Reconfigured from Monitoring Analytics, "State of the Market Report for PJM: 2020," Volume 2, Detailed Analysis, Figure 1-1, p. 5, 2020 State of the Market Report for PJM (monitoringanalytics.com)

[5] The 100% RPS states include: Illinois by 2050, Maryland by 2040, New Jersey by 2050, Virginia by 2045 and Washington, DC by 2032.

Figure 2: Renewable and Carbon Reduction Goals by PJM State[6]

State	RPS Targets	Economy-wide Carbon Emissions Targets[7]
Delaware	40% by 2026	30% below 2008 levels by 2030
Illinois	45% by 2026, 100% by 2050	26-28% below 2005 levels by 2025
Indiana	10% by 2025	-
Kentucky	-	-
Maryland	50% by 2030, 100% by 2040	50% below 2006 levels by 2030, carbon neutral by 2050
Michigan	15% by 2021	28% reduction by 2025, carbon neutral by 2050
North Carolina	12.5% by 2021	70% below 2005 levels by 2030, carbon neutral by 2050 (power sector specific)
New Jersey	50% by 2030, 100% by 2050	80% below 2006 levels by 2050
Ohio	8.5% by 2026	-
Pennsylvania	18% by 2021	26% below 2005 levels by 2025, 80% by 2050
Tennessee	-	-
Virginia	100% by 2045 (Dominion) 100% by 2050 (AEP)	Net zero by 2045
Washington, DC	100% by 2032	50% below 2006 levels by 2032, 80% by 2050
West Virginia	-	-

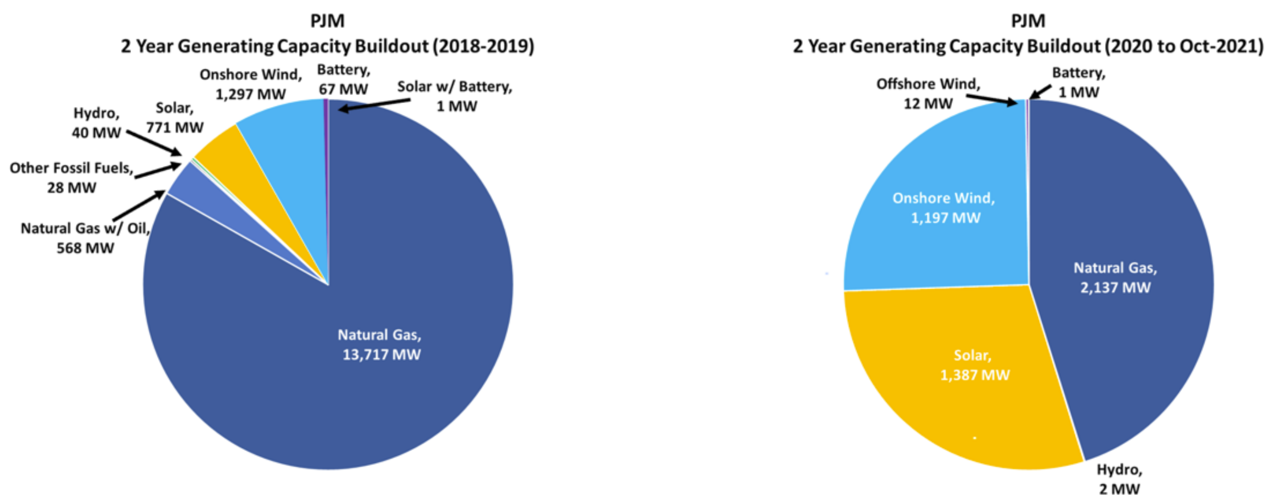
Those states with RPS and carbon reduction policies have put into place multiple programs to achieve these goals including renewable subsidies, net metering credits, and utility mandates for purchases from specific generation technologies such as offshore wind and batteries. Some have begun drafting legislation to prohibit new fossil fuel units from being built, and/or forcing retirement of carbon-emitting generation by a certain date. As a result, investment in generation in those states has moved away from fossil fuels towards renewables and alternative energy resources.

1.2 PJM's recent generation build-out and queue entries reflect state policies

Since the last quadrennial review, PJM's generation build-out has seen a dramatic shift away from fossil fuel units to solar and wind generation projects (**Figure 3**).

[6] Energyzt analysis of DSIRE summary of state policies, Database of State Incentives for Renewables & Efficiency® - DSIRE (dsireusa.org) These goals are established by a combination of executive order, statute, and legislation, depending on the state.
[7] North Carolina's carbon emissions reduction targets are specific to the power sector. All others are economy-wide.

Figure 3: Shift in PJM Generation Build-out since 2018[8]

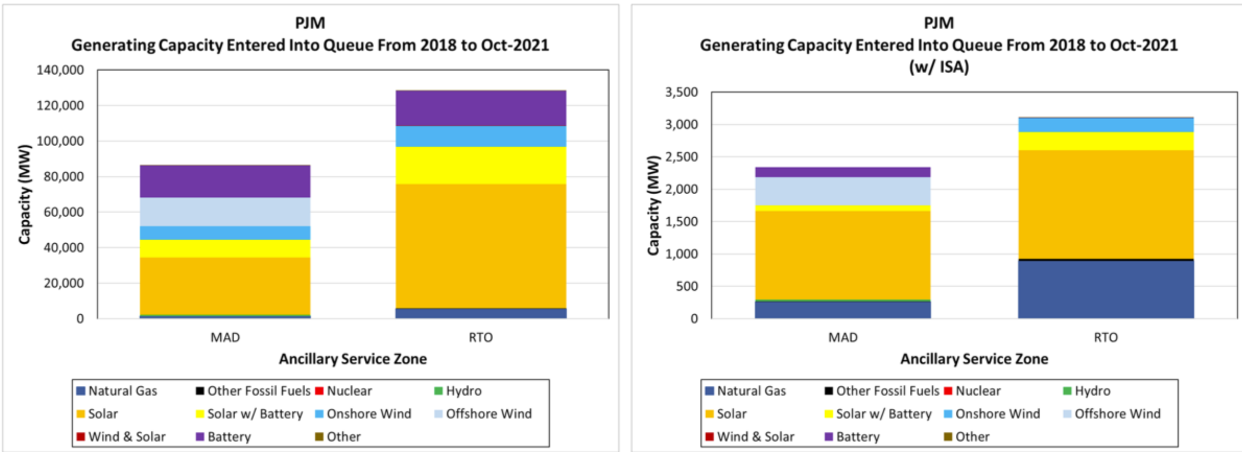


This build-out towards clean energy is likely to continue as PJM's queue has been dominated by resources that reflect state policy goals. Of the total capacity that is in the queue, projects are dominated by solar, solar/battery hybrids, onshore and offshore wind, and batteries. Controlling for the smaller portion of the projects that have an Interconnection Service Agreement ("ISA"), clean energy projects dominate both the Mid-Atlantic Dominion ("MAD") sub-zone projects and the Regional Transmission Organization ("RTO") sub-zone projects. Of all the projects with ISAs, solar projects dominate the queue (**Figure 4**).

An appropriate reference unit should be a technology that can be developed in a given region. The combination of PJM state policies, recent generation build-out, and recent queue entries that are dominated by renewable resources indicate that developers are following state policy goals. The declining portion of fossil fuel projects in the queue along with the dominance of clean energy projects entering into the queue illustrates the market transition to renewable resources that already is underway.

[8] Energyzt analysis of PJM Queue data.

Figure 4: Evolution of PJM Queue [9]



The RPM reference unit should reflect this transition.

1.3 State policies support a smaller, modular, more flexible technology

A clean energy transformation is underway. PJM's elimination of the MOPR reflects this transition and allows renewable units to bid into the RPM at prices that incorporate subsidies and may be well below the competitive cost of the clean energy technology. Some states with clean energy policies already are legislating limitations on existing fossil fuel units and starting to refuse to grant operating permits to fossil fuel units that are counter to the state's renewables and carbon reduction goals. However, PJM still operates a capacity market that procures power supply obligations to provide reliability to the entire system. The parameters of that market need to reflect the operating and cost characteristics of an appropriate reference unit that can be sited, built, and attract financing within the broader PJM area. Zonal adjustments should be made as required to be consistent with legislated policy goals.

At this time, fossil fuel units are continuing to enter into the queue and receive ISAs. PJM includes states that do not have any carbon reduction goals and could site a new fossil fuel unit readily. If this changes over time, along with merchant entry of clean energy projects, the reference unit of the future may need to reflect an alternative energy investment that offers a similar level of reliability as a traditional fossil fuel unit with fuel on demand.

[9] Ibid.

For the time being, however, the PJM reference unit can still reflect a fossil fuel unit despite the growing number of states with clean energy goals that could preclude such technology going forward. The appropriate reference unit, however, should have operating characteristics that are compatible with and valuable in a market that is transitioning to a decarbonized system with increasing levels of renewable energy. Such systems require quicker ramping requirements and fast-start capabilities without significant expectations of dispatchable energy that would contribute to carbon emissions. Growing uncertainty also would support a smaller, more modular technology. Projected economic life should be shorter than the technical life, to reflect legislative phase-out of fossil fuel generation and shorter financing tenors. Under these criteria, a combustion turbine, aeroderivative engine, or reciprocating engine would be the most appropriate technology to use for a reference unit. Of these options, the combustion turbine has the lowest Net CONE.[10]

Growing uncertainty with respect to policy and economic lifespan is likely to encourage lower-cost capital investment commitments. Smaller, more modular units with lower upfront capital cost requirements are more likely to be favored over larger, more expensive commitments. Financing also should reflect a reduced appetite for leverage by investors given revenue uncertainty. Financing tenors should reflect the greater uncertainty around merchant generation, especially fossil fuel units.

1.4 States with renewable policy goals are refusing to permit fossil fuel units

Although a combustion turbine is an appropriate reference unit for the RTO zone, it may not be appropriate for specific zones. One of the key criteria for an appropriate reference unit is the ability to site and operate that unit. PJM is a large geographical area that can site a new unit with certainty, most likely in states without aggressive clean energy policies. Once the ability to site a new project within a specific zone or state is considered, however, environmental policies can limit or outright prohibit siting and operation of fossil fuel units.

Within PJM, a number of states have taken proactive measures to retire carbon-emitting units and reduce carbon emissions throughout their economy. It is difficult to support an

[10] Relative to the combustion turbine, aeroderivatives and reciprocating engines have a higher gross CONE. Although they have more efficient heat rates and would be expected to be dispatched more frequently, public estimates presented below indicate that their levelized costs remain above those of a combustion turbine.

assumption that they would permit fossil fuel replacements. For example, Illinois, New Jersey, and Virginia have taken the lead on legally limiting fossil fuel power plants:

- **Illinois:** On September 15, 2021, Illinois Governor J. B. Pritzker signed the Climate and Equitable Jobs Act into law which, among other things, requires all private coal-fired and oil-fired electric generating units to reach zero emissions by January 1, 2030. All privately-owned natural gas-fired units must reach zero emissions by 2045, subject to several interim targets that are designed to force closures prior to those dates.[11]

- **New Jersey:** On November 15, 2021, the New Jersey Senate passed Senate Resolution 17 which urges the Governor to impose an immediate moratorium on fossil fuel project until, ". . . the State adopts rules regulating CO2 and other climate pollutants adequate to achieve the 80 percent reduction in greenhouse gas emissions from 2006 levels by 2050 as required under the Global Warming Response Act."[12]

- **Virginia:** On April 11, 2020, Virginia Governor Ralph Northam signed the Virginia Clean Economy Act into law which, among other things, creates a "schedule by which Dominion Energy Virginia and American Electric Power are required to retire electric generating units located in the Commonwealth that emit carbon as a by-product of combusting fuel to generate electricity."[13] Specifically, by December 31, 2045, all electric generating units located in Virginia that "emit carbon as a by-product of combusting fuel to generate electricity" would be required to retire unless the utility petitions the Commission and the Commission agrees that retirement would cause reliability to be threatened.[14]

For these states, the goals have been established and are in the process of being legislatively backstopped. The assumption should be that no fossil fuel units can be permitted in these states within the next few years. Even if such units can be permitted, their projected lifespan would be no more than twenty years in light of the legislated retirement requirements.

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[11] Illinois Press Release, "Gov. Pritzker Signs Transformative Legislation Establishing Illinois as a National Leader on Climate Action," September 15, 2021, https://www.illinois.gov/news/press-release.23893.html

[12] Assembly Resolution No. 77 State of New Jersey 2019th Legislature Pre-filed for Introduction in the 2020 Session, https://www.njleg.state.nj.us/2020/Bills/AR/77_I1.PDF

[13] Virginia's Legislative Information System, 2020 Session, Chapter 1193, https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+CHAP1193

[14] Ibid.

States outside of PJM illustrate that executively ordered mandates and/or explicit legislative restrictions are not required for states to prevent permitting of fossil fuel units. For example, in New York, two recent air permit applications for a combined cycle and combustion turbine were rejected, in part, because the fossil fuel units were inconsistent with the state's emissions limit laws.

- **New York – Danskammer Energy Center:** On October 27, 2021, the New York State Department of Environmental Conservation issued a Notice of Denial of Title V Air Permit to the Danskammer Energy Center which requested a permit to build a new 536 MW combined cycle on its existing plant site. The project was denied, in part, because it "would be inconsistent with or would interfere with the attainment of the Statewide greenhouse gas (GHG) emission limits established in Article 75 of the Environmental Conservation Law (ECL)."[15]

- **New York – Astoria Gas Turbine Power, LLC:** On October 27, 2021, the New York Statement Department of Environmental Conservation denied Astoria a permit to construct a new simple cycle dual fuel fossil fuel-fired peaking combustion turbine generator of 437 MW. Again, greenhouse gas emission limits established in Article 75 of the ECL were cited as a rationale.[16]

These examples show that there does not need to be an outright ban or prohibition on building new fossil fuel units for state permit authorities to refuse to allow a new or repowered plant to be built. Even if siting permits can be granted, failure to obtain operating permits in light of state policies and emissions reduction goals may halt any construction.

1.5 An alternative reference unit may be required for zones with net zero goals

The transition to clean energy would support using a resource with characteristics that meets system needs for reliability with carbon reduction goals and greater levels of

[15] Letter to Ms. Brenda D. Colella and Ms. Danielle E. Mettler-LaFeir from the New York Department of Environmental Conservation Re: Notice of Denial of Title V Air Permit DEC ID: 3-3346-00011/00017 Danskammer Energy Center – Town of Newburgh, Orange County Title V Air Permit Application, October 27, 2021. https://www.dec.ny.gov/docs/permits_ej_operations_pdf/danskammerdecision102721.pdf

[16] Letter to Mr, Andrew Scano from the New York Department of Environmental Conservation Re: Notice of Denial of Title V Air Permit DEC ID: 2-6301-00191/00014 Astoria Gas Turbine Power - Astoria, Queens County Title V Air Permit Application, October 27, 2021, https://www.dec.ny.gov/docs/administration_pdf/nrgastoriadecision10272021.pdf

renewable resources. Such resources should reflect system reliability needs, the ability to obtain siting and operating permits, and consistency with implementation of environmental goals. For these states, there are a number of alternative reference resources that could be chosen for PJM states unlikely to permit fossil fuel units. For example:

- **Hybrid Solutions:** The appropriate reference unit for states with environmental policies regarding generation type or emissions reductions may not realistically be a natural gas-fired unit or a transmission upgrade for reliability, requiring a renewable/storage hybrid solution or other alternative to reflect limitations on siting carbon-emitting generation resources.

- **Fossil Fuel Units with Carbon Capture Systems:** Carbon capture systems add capital and operating costs to a standard fossil fuel unit, but may be required to mitigate concerns over conflicts with carbon emissions policy goals. Such capital costs should be included in any reference unit that emits carbon in zones where retirement or carbon mitigation is required.

- **Transmission Solutions:** Another alternative for states with clean energy goals could be a combustion turbine located in another part of PJM with associated transmission costs to ensure reliability in a state that would not otherwise permit the plant due to environmental policies and goals. Although not in keeping with the spirit of the state goals, importing reliability through a new transmission line may be the most practical and cost-effective solution for states with clean energy goals that need reliable capacity.

- **Reduced Operating Life and Clean Resource Replacement:** If a fossil fuel reliability unit is assumed to be permitted in states with 100% RPS goals, such plants would need to have an assumed lifespan consistent with those goals or shorter (e.g., retirement by 2045 in Virginia). The capital cost of replacement in the future also may need to be incorporated to reflect the policy requirements for reliability.

There are a number of ways to provide reliability to states with strong renewables or carbon emissions goals. Ensuring an appropriate reference unit for those zones requires appropriate consideration of permitting limitations and feasible alternatives for ensuring reliability.[17] In valuing these clean energy options, however, it is important to recognize that parameters surrounding the reference unit may differ from those of a fossil fuel unit. Specifically:

- **Merchant:** RPM is procuring merchant capacity to meet incremental reliability requirements in PJM. Any specification of a clean energy resource should reflect the capital costs, operations, and financing terms of a merchant plant versus an asset operating under a long-term power purchase agreement.

- **Reliability Characteristics:** An appropriate reference unit should have the ability to provide reliability and load carrying capability on par with fossil fuel units. In the case of intermittent renewable resources, the costs of battery storage or another firming mechanism would need to be included to provide that equivalency.

- **Financing Terms:** The specified clean energy reference unit should be financeable, and reflect the costs and conditions associated with financing merchant units. Tax equity financing generally is provided by banks subject to stringent credit and risk management procedures. Merchant renewable projects in Texas are financed only if they have hedged a portion of their revenues streams adequate to cover debt payments. Tenors tend to be shorter for merchant facilities, generally seven to ten years, requiring refinancing to occur multiple times over the life of the asset.[18] Tax equity financing costs needs to be properly incorporated.

Accuracy is key. Simplifying characteristics of clean energy resources for purposes of estimating the CONE and Net CONE risks introducing needless error into the parameters for those zones.

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[17] Adopting a higher-priced unit consistent with a clean energy future could result in higher equilibrium prices for that zone. Some may argue that the clean reliability premium should not be paid to existing fossil fuel units. However, economics and competitive market pricing would support a single clearing price and paying the premium to existing fossil fuel units because the entry cost of a clean energy resource reflects the cost of the next best unit in the event that an existing fossil fuel unit retires.

[18] For a more detailed discussion regarding a number of considerations surrounding use of a clean energy resource as a reference unit, see the testimony on the offer review trigger price for New England's offshore wind projects submitted in the Joint Affidavit of Richard D. Homich and Dennis Moritz on Behalf of the New England Power Generators Association, Inc. Docket No. ER21-1637-000 Filed April 28, 2021, https://nepga.org/wp-content/plugins/custom-post-type-attachment-pro/download.php?id=MTc4MQ==&file=Mg==

Key Insights:
Given the number of PJM states with RPS requirements and carbon emission reduction goals, and growing integration of renewable resources, the most appropriate fossil fuel unit to use would be a fast-start, quick-ramp, low up-front capital cost technology such as a combustion turbine.

For zones where states have stated renewables or carbon emissions reduction goals, the ability to permit the reference unit needs to be considered. To this end, a more expensive alternative such as the reference unit plus transmission, carbon capture and storage, a reduced operating life consistent with environmental goals, a renewable hybrid solution, or other politically feasible solution to supply reliability to the PJM system should be chosen to set the parameters for that zone.

2. THERE ARE A NUMBER OF COMPETING TECHNOLOGIES

Power generation is experiencing a technological revolution. Whereas the past thirty years saw incredible efficiency gains in natural gas-fired combined cycles, the past five years have seen significant cost declines in clean energy resources and the technologies required to support them. In U.S. electricity markets that have experienced significant levels of renewable integration, combustion turbines, aeroderivatives, and reciprocating engines with faster operational response speeds have been and are being built to support the decarbonized grid. This section describes the types of generation technologies that are commercialized throughout the U.S. and how their pricing compares to the traditional reference unit choices of combustion turbines and combined cycles.

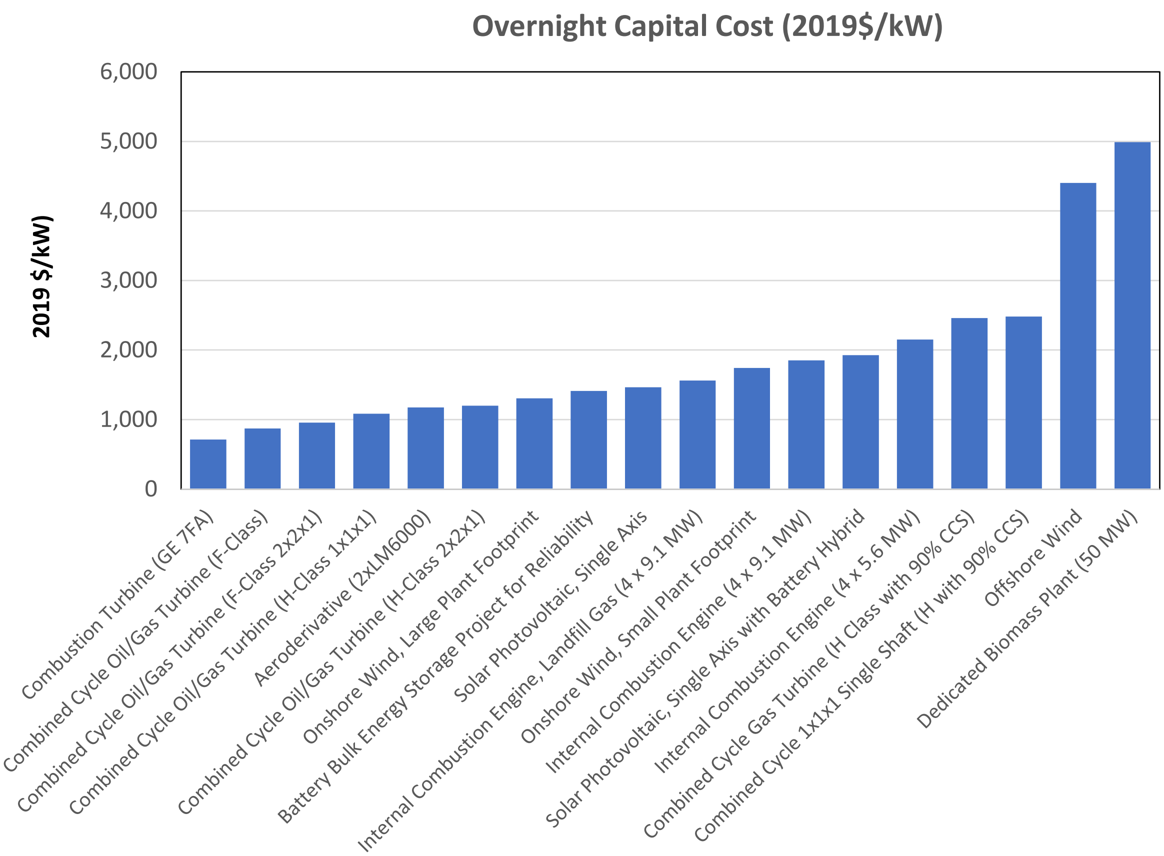
2.1 New technologies are becoming increasingly competitive

A number of new generation technologies are becoming less costly to build, offering different operating characteristics in exchange for slightly higher prices. During the last quadrennial review, Sargent & Lundy provided capital cost estimates for alternative technologies to calculate Gross CONE. Since then, Sargent & Lundy has provided detailed cost estimates in support of the Energy Information Administration's Annual Energy Outlook ("AEP") in 2020, which were used again in the 2021 AEO.

Sargent & Lundy provides adjusted estimates by state in the AEO supporting documents. As shown in **Figure 5**, their estimates for Pennsylvania and New Jersey indicate that simple cycle combustion turbines have the lowest up-front capital cost followed by combined cycles (whether F-class or H-class).

Aeroderivatives are on par with H-class combined cycles in a 2x2x1 configuration. The GE H-class turbines are more expensive on a capital cost basis than the F-class, but have more efficient heat rates. Internal combustion engines are smaller and more expensive, but on par with renewables. The capital cost for simple cycle combustion turbines is less than the cost of a combined cycle. On an overnight capital cost basis, Sargent & Lundy estimates that the GE Frame H combined cycle technologies would cost above $1,000 / kW.

Figure 5: Sargent & Lundy Comparison of Capital Costs across Technologies[19]



A recent NYISO Net CONE exercise found the same relative cost relationship between the combustion turbine and combined cycle costs. Estimates presented by Analysis Group

[19] Sargent & Lundy, *Capital Cost and Performance Characteristic Estimates for Utility Electric Power Generation Technologies*, February 2020, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

and Burns & McDonnell estimate the cost of a Frame H Combustion Turbine without a Selective Catalytic Reduction ("SCR") at around $830 - $840 / kW; with SCR is above $1,000/ kW. The cost of a Frame H Combined Cycle with SCR comes in at around $1,400 / kW for Central New York (**Figure 6**).

Figure 6: NYISO Net CONE Capital Cost Estimates ($2020/kW)[20]

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
3x0 Siemens SGT-A65	$1,928	$1,945	$2,099	$2,161	$2,680	$2,211
1x0 GE 7F.05 (with Dual Fuel and SCR)	$1,315	$1,324	$1,342	$1,403	$1,817	$1,488
1x0 GE 7F.05 (Gas Only, without SCR)	$1,072	$1,082	-	-	-	-
1x0 GE 7HA.02 (with Dual Fuel and SCR)	$1,050	$1,054	$1,065	$1,100	$1,353	$1,170
1x0 GE 7HA.02 (Gas Only, without SCR)	$831	$837	-	-	-	-
Informational Combined Cycle Plants						
1x1 GE 7HA.02 (with SCR)	$1,401	$1,421	$1,547	$1,649	$1,961	$1,832
Energy Storage						
BESS 4-hour	$1,539	$1,552	$1,565	$1,620	$1,910	$1,649
BESS 6-hour	$2,146	$2,166	$2,184	$2,263	$2,592	$2,326
BESS 8-hour	$2,753	$2,778	$2,802	$2,906	$3,273	$3,004

Note:
[1] Estimates for the Siemens SGT-A65 and informational 1x1 GE 7HA.02 combined cycle units are specified with dual fuel in Load Zone G (Dutchess County), Load Zone G (Rockland County), NYC, and LI, and are specified as a gas-only design in Load Zone C and Load Zone F.
[2] All estimates include construction financing costs.

Contrast this with the assumptions adopted by PJM during the last quadrennial review and recent updates. Whereas NYISO consultants, Lazard, the EPA, and EIA all place the overnight capital cost of combined cycles higher than combustion turbines, only NREL adopted a price that has combined cycles at a cost on par with combustion turbines. PJM's chosen capital cost for combined cycles used in recent MOPR calculations was similar to the NREL relationship, placing capital costs for combined cycles on par with combustion turbines, an outlier when compared to other publicly-available estimates (**Figure 7**).

[20] Analysis Group and Burns & McDonnell, "Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Interim Final Draft Report," August 5, 2020, Table 24, p. 47, 214567fb-b960-233f-bcda-4b919678bce4 (nyiso.com)

Figure 7: Comparison of Capital Cost Estimates ($/kW) Used by PJM[21]

Technology	NREL 2022	Lazard 2019	EPA 2021	EIA 2019	PJM
Nuclear	6,506	6,900 – 12,200	5,644	6,041	6,041
Coal	3,944	3,000 – 6,250	3,580	3,676	3,676
Combined Cycle	894	700 – 1,300	1,081	1,084 (H)	874
Combustion Turbine	905	700 – 950	662	713 (7FA)	875
Solar PV (tracking)	1,343	1,100	1,034	1,313	1,313
Solar PV (fixed)	*1,262	900		1,234*	1,234
Onshore Wind	1,472	1,100 – 1,500	1,404	1,677	1,677
Offshore Wind	3,682	2,350 – 3,550	4,529	4,375	4,375
Battery Storage	1,157	898 – 1,874	N/A	1,389	1,389

** Fixed cost obtained from multiplying Tracking cost by 0.94*

Given the more efficient heat rate of combined cycles, equating their capital costs ensured that the Net CONE for combined cycles would always come in lower than combustion turbines given the energy and ancillary services ("E&AS") offset. As a result, estimates for Net CONE included in PJM's analyses for both 2020 and 2021 put the cost of combined cycles well below the cost of alternative technologies (**Figure 8**). It also is important to note that aeroderivatives and reciprocating engines are not even included in the Net CONE estimates.

[21] PJM, Market Implementation Committee, "Default MOPR Floor Offer Prices for New Generation Capacity Resources," March 11, 2020.

Figure 8: Comparison of Net CONE Estimates ($/MW-Day) Used by PJM[22]

Resource Type	Gross CONE ($/MW-Day) (Nameplate)	Average Zonal E&AS Revenue Offset ($/MW-Day) (Nameplate)	Net CONE ($/MW-Day) (Nameplate) Net Reactive Offset	Capacity Value (Percent of Nameplate)	Net CONE ($/ICAP MW-Day)
Nuclear	2,000	420	$1,570		$1,570
Coal	1,068	36	$1,023		$1,023
Combined Cycle	320	195	$116		$116
Combustion Turbine	294	62	$226		$226
Solar PV (Tracking)	290	153	$128	60.0%	$213
Solar PV (Fixed)	271	94	$168	42.0%	$400
Onshore Wind	420	203	$208	17.6%	$1,182
Offshore Wind	1,155	284	$862	26.0%	$3,315
Battery Storage	532	429	$93	40.0%	$233
Energy Efficiency	644	517	$127		$127
Demand Resp. (Gen)	254	0	$254		$254

For this Quadrennial Review, the Brattle Group has offered initial estimates of Gross CONE and Net CONE for a limited set of generation technologies: 1) A combustion turbine (1x0 7HA.02); 2) a gas combined cycle (1x1 7HA.02 with duct firing); and 3) An indicative combined cycle (2 x 1).[23]

Values that would have been higher due to escalation are offset by the assumption of a 30-year technical life which reduces CONE by $40-45/ICAP MW-day.[24] Brattle also notes that their estimated cost for a new combustion turbine is $55 to $114/MW-day above recent RPM clearing prices whereas the estimated costs of combined cycles are within the range of recently-cleared prices. Brattle's estimated costs have the following shortcomings:

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[22] PJM, Market Implementation Committee, "Default MOPR Floor Offer Prices for New Generation Capacity Resources," March 11, 2020; update provided https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20200311/20200311-item-06c-default-mopr-cone.ashx

[23] Fifth Review of the Variable Resource Requirement Curve PRESENTED BY Samuel Newell Michael Hagerty Travis Carless GROSS CONE AND E&AS DRAFT RESULTS PRESENTED TO PJM Market Implementation Committee DECEMBER 8, 2021.

[24] Ibid., p. 5.

1) **Inconsistency with Public Estimates:** The estimated cost of a CC 1 x 1 are well below other cost estimates in the public domain, including those submitted by Burns & McDonnell as part of the NYISO review in 2021 and the 2020 estimates from Sargent & Lundy used by the EIA.

2) **Cost-free Life Extension:** Brattle extends the life of the technology from 20 years to 30 years without any discussion of the incremental costs required to ensure operational reliability for that extended term. Brattle specifically notes this omission: "The long-term service agreement (LTSA) costs included in the O&M costs are expected to cover all costs necessary to maintain unit performance for over 30 years, but does not include capital projects or major equipment replacement that may be necessary to further extend the life."[25]

3) **Financing Tenor and Costs:** Financing is not available for merchant power plants for 20 years, let alone 30 years. Any estimated cost needs to reflect this reality and include the costs of multiple refinancings along with the projected interest rates at which such financing can occur based on the yield curve. Such costs of capital also should be applied to the capital investment required to extend the operating life of the plant to 30 years.

4) **Calibration to Current Prices is Inappropriate:** The Brattle presentation claims that extending the life to 30-years is more consistent with where RPM prices are clearing. However, prices are clearing below the cost of new entry on the VRR Curve as is consistent with excess supply that PJM currently is experiencing. Resetting the parameters of the reference unit to match current clearing prices is inappropriate. If prices start to clear above the Net CONE, is it appropriate to reduce the technical life of the reference unit to match the higher prices?

5) **No Basis for a Life Extension:** The Brattle Group's recommendation to extend the plant life to 30 years is unsupported. The fact that the technical life of fossil-fuel power plants can be extended does not necessarily mean that the reference unit should be assumed to have a longer life. Similarly, a recommendation by the IMM that the life should be 35 years, without any associated costs, lower efficiency, or increased outage rates risks, also provides no basis for extending the life of the reference unit. Indeed, it is unclear whether both combined cycles and combustion turbines should have the same life extension; combined cycles could be more likely than combustion turbines to retire earlier due to decarbonization goals and higher

[25] Ibid., p. 13.

capital costs.

The Brattle Group's initial screening and CONE estimates are limiting and require additional support before they can be considered valid estimates. Depending on market conditions and operating characteristics needed in the market to maintain reliability, technologies other than combined cycles and combustion turbines can be competitive options and, in some cases, may be the only option.

2.2 Updated cost estimates should reflect inflation

Many of the cost estimate sources referenced by PJM and relied upon by the Brattle Group have been updated since the last quadrennial review.

As already noted, Sargent and Lundy issued updated cost estimates in 2020 as part of the EIA AEO.[26] EIA used these same updated costs in its 2021 AEO.[27]

NREL also updated its capital cost values for generation resources. Although the prior NREL cost estimates placed the cost of combustion turbines and combined cycles close to par in their 2019 estimated overnight capital costs, the updated cost estimate are more consistent with the relative relationship calculated by other sources. In particular, combined cycle costs are now around 14 percent higher than those of a combustion turbine.

Figure 9: Comparison of NREL Overnight Capital Cost Estimates ($/kW)[28]

Overnight Capital Cost ($/kW)	2019	2021
Combustion Turbine	$899	$914
Combined Cycle	$906	$1,042

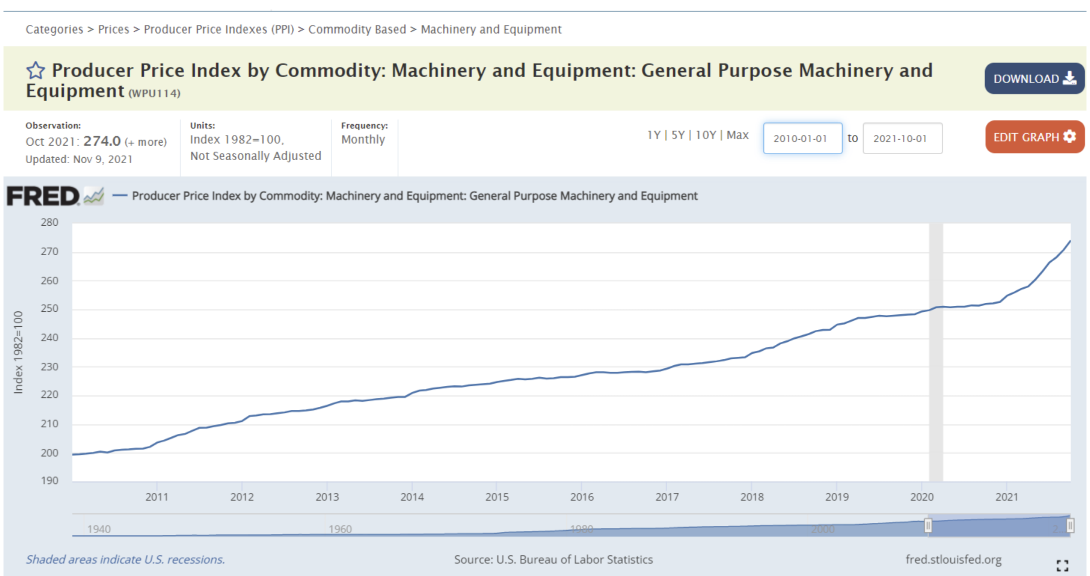
Once again, it appears that Brattle is basing their approach on a methodology similar to NREL, or somehow obtaining similar results. NREL continues to be an outlier compared to other public estimates.

[26] Sargent & Lundy, *Capital Cost and Performance Characteristic Estimates for Utility Electric Power Generation Technologies*, February 2020.
[27] Confirmed by Energyzt with conversation with the EIA.
[28] 2019 version: https://atb-archive.nrel.gov/electricity/2019/data.html; 2021 version: https://data.openei.org/submissions/4129

Furthermore, any estimate using 2021 cost assumptions needs to be escalated to 2025/26 to reflect inflation. Following the pandemic, supply chain disruptions and government money injected into the economy has created higher levels of inflation than have been experienced in recent years. In developing PJM's Net CONE during the past quadrennial review, Brattle used an inflation assumption of a long-term inflation rate of 2.2% based on Cleveland Federal Reserve website. Since then, expectations have declined, primarily driven by the Federal Reserve's monetary policies that have lowered Treasury yields such that implied inflation estimates are 1.74% versus 2.2%.[29] Given inflation, however, the Federal Reserve has indicated that it will start raising interest rates as early as 2022, in multiple tranches, and the market already has responded.

In contrast to Treasury Yields, the escalation rate for equipment and labor derived from the BLS Producer Price Index machinery and equipment has increased by 8.8 percent over the past year versus a 20-year annual average growth rate of 3.0 percent (**Figure 10**). The Brattle Group used the BLS Producer Price Index to estimate the real growth rate of overnight capital costs for new generation. Recent changes in inflation should not be ignored during this quadrennial review.

Figure 10: Producer Price Index for All Commodities (2000 – 2021)[30]



[29] Federal Reserve Bank of Cleveland (2017), Cleveland Fed Estimates of Inflation Expectations, https://www.clevelandfed.org/our-research/indicators-and-data/inflationexpectations.aspx

[30] Bureau of Labor Statistics, Producer Price Index by Commodity: Machinery and Equipment, https://fred.stlouisfed.org/series/WPU114

Despite the Federal Reserve's initial exhortations that inflation was transitory, it is expected to continue for at least the near term. An appropriate inflation adjustment to cost estimates developed in 2021 should be applied to reflect the near-term expectations regarding inflationary conditions relevant industries are experiencing when bringing capital costs forward to 2026. Applying a long-term inflation rate expectation would not be appropriate in the short-term given supply chain challenges in meeting demand recovery following the pandemic.

In its December 2021 presentation, the Brattle Group proposes an inflation assumption of 2.0% inflation based on the latest long-term inflation estimates projected by Cleveland Fed and Blue Chip Economic Indicators, which are in the range of 1.8 – 2.0%.[31] Although their sources and estimates are accurate, the application is inappropriate. Capital costs to build a plant that would be operational by the 2025/26 period will increase according to short-term inflation rates. Even one year of high inflation, as is currently being experienced, will increase overnight capital costs of a new generating unit. Capital costs for the reference unit should reflect short-term inflation rates as opposed long-term rates which are likely to regress to the target.

2.3 Focusing on the lowest cost unit can adversely impact reliability

The clustered costs for competing technologies illustrate a potential hazard of relying on the lowest cost alternative. PJM's assumptions for combined cycles have been using an outlier for the capital cost, resulting in a significantly lower price than competitive alternatives. If PJM were to choose this representation of a combined cycle as the reference unit, it could create barriers to entry for high quality reliability resources and adversely impact reliability.

PJM recently proposed eliminating the MOPR, a proposal that went into effect via operation of law because it was unable to garner support from a majority of the Commission.[32] Given elimination of the MOPR, renewable resources will be able to bid into the PJM RPM market without being subject to a minimum offer price based on an unsubsidized, competitive market bid. This change alone can be expected to decrease RPM prices as renewable resources bid in their qualified capacity with zero to minimal marginal cost of capacity.

[31] Fifth Review of the Variable Resource Requirement Curve, December 8, 2021, p. 20.

[32] Federal Energy Regulatory Commission, PJM, L.L.C., Docket No. ER21-2582-000, Statement of Chairman Glick and Commissioner Clements (October 19, 2021), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211019-4001&optimized=false

Choosing a lower cost resource than a combustion turbine as the appropriate reference unit could challenge a stable price signal. More expensive resources that can provide flexible capacity on demand would not be valued and could be less likely to clear the market. PJM may clear a higher portion of intermittent resources to meet its capacity requirements. Although PJM is engaged in developing the ELCC process to qualify reliability resources, the net result could be a set of cleared resources that adversely impact system reliability in three ways:

1) **Bidding Barriers:** New technologies that could provide system reliability due to superior operating characteristics could be precluded from bidding or being competitive due to the lower maximum price on the demand curve set by the lower Net CONE cost estimate for a reference unit; and

2) **Reduced Quality of Reliability Resources:** Despite the ELCC, RPM could experience increased reliance on renewable resources that now clear, but would not be available on demand to provide reliability at all times.

3) **Fat Tail Events:** The potential for low probability, high impact events could challenge reliability if multiple resources qualified through ELCC are not available at the same time due to common events.

PJM avoided adding unnecessary regulatory volatility to RPM prices during the last quadrennial review by remaining with the combustion turbine as the reference unit. Despite an appeal that argued the lowest cost resource should be chosen, the U.S. Court of Appeals determined that the higher cost combustion turbine was justified for incorporation into the Variable Resource Requirement ("VRR") curve:

> The Commission reasonably determined that an oversupplying combustion turbine plant-based VRR Curve, at a modest cost increase, was compatible with consumer interests because it ensured reliability more consistently than a combined cycle plant-based VRR Curve.[33]

[33] United States Court of Appeals FOR THE DISTRICT OF COLUMBIA CIRCUIT, Argued April 6, 2021, Decided July 9, 2021, No. 20-1212 DELAWARE DIVISION OF THE PUBLIC ADVOCATE, ET AL., PETITIONERS v. FEDERAL ENERGY REGULATORY COMMISSION, RESPONDENT PJM INTERCONNECTION, L.L.C., INTERVENOR On Petition for Review of Orders of the Federal Energy

Given the significant changes that already have been made to RPM, changing rules due to ELCC, and increased uncertainty in market conditions going forward as higher levels of renewable resources are integrated into PJM's markets, modifying the reference unit to a combined cycle compounds what already will be dramatic changes to the RPM market. To ensure reliability and allow for new technologies to compete, the reference unit should be a consistent technology that provides reliable capacity upon demand.

2.4 PJM's markets already limit the entry of new technologies

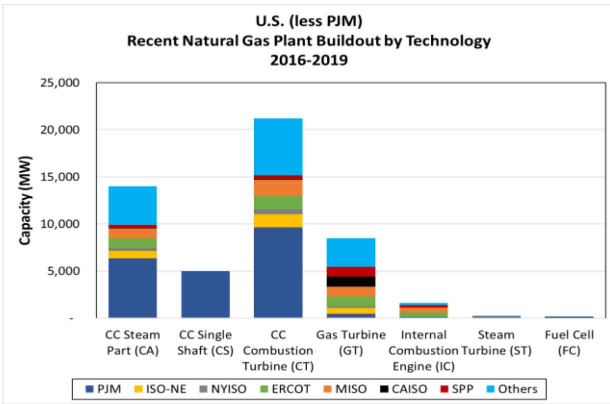
Fossil fuel generation build-out in PJM has been primarily combined cycle combustion turbines, combined cycle steam turbines, and combined cycle single shaft turbines.

Markets such as California (CAISO) and Texas (ERCOT) that have experienced greater integration of renewables than PJM have seen a greater number of gas turbines and internal combustion turbines. **Figure 11** illustrates the generation technology build-out in PJM versus other markets between 2016 and 2019.

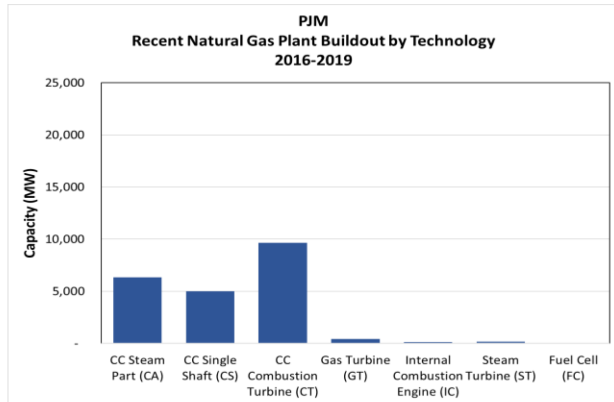
Regulatory Commission, p. 12, Footnote 6.
https://www.cadc.uscourts.gov/internet/opinions.nsf/C58F501FCCA3ABCE8525870D0050CBAC/$file/20-1212-1905643.pdf

Figure 11: Natural Gas Generation Technology Build-out 2016-2019[34]

U.S. RTO/ISO Build-out



PJM Build-out



Natural Gas Recent Buildout 2016-2019

Location	CC Steam Part (CA)	CC Single Shaft (CS)	CC Combustion Turbine (CT)	Gas Turbine (GT)	Internal Combustion Engine (IC)	Steam Turbine (ST)	Fuel Cell (FC)	Total
PJM	6,347	4,988	9,630	439	127	161	10	21,701
ISO-NE	801	-	1,418	644	5	-	23	2,890
NYISO	300	-	470	140	-	-	8	917
ERCOT	1,020	-	1,442	1,069	502	-	-	4,032
MISO	1,056	-	1,742	1,028	478	33	-	4,336
CAISO	16	-	71	1,109	7	-	85	1,288
SPP	350	-	369	993	265	-	-	1,976
Others	4,123	-	6,053	3,072	212	1	3	13,464
Total	**14,012**	**4,988**	**21,195**	**8,492**	**1,594**	**195**	**128**	**50,604**
% of Total (PJM)	**29%**	**23%**	**44%**	**2%**	**1%**	**1%**	**0%**	**100%**
% of Total (Less PJM)	**27%**	**0%**	**40%**	**28%**	**5%**	**0%**	**0%**	**100%**
PJM % of Total for Technology	**45%**	**100%**	**45%**	**5%**	**8%**	**83%**	**8%**	**43%**

Energyzt reached out to manufacturers of both aeroderivatives and reciprocating engines to understand the discrepancy between PJM and other markets. Those conversations indicated that there were three primary factors preventing opportunities for these technologies in PJM:

1) **Renewable Integration:** PJM is still in the initial stages of renewable integration versus other markets that require faster response capabilities;

2) **Reliance on a Single Type of Resource:** PJM's market design does not distinguish between operating characteristics of different capacity resources, making it more difficult to finance superior reliability resources; and

3) **Market Design:** PJM RPM design is based on a single reference unit for parameters that limit entry of other technologies.

[34] EIA, Form EIA-860 (2016-2019). https://www.eia.gov/electricity/data/eia860/

Both aeroderivatives and internal combustion engines have had better success in selling their generation technology capabilities to vertically integrated utilities, municipal light companies, and electric cooperatives where negotiations are done bilaterally for valued attributes versus through a standardized product procured through a central market. Given the success of these more flexible resources in other markets, PJM's RPM market design decisions should choose a reference unit that establishes parameters that allow for inclusion rather than exclusion of alternative technologies.

Key Insights:
A number of generation technologies with more flexible operating characteristics are becoming more competitive. In other markets with increased renewable penetration, combustion turbines, aeroderivatives and reciprocating engines have proliferated. PJM's Net CONE calculations have not considered these alternative technologies, and therefore could block them from participating in the RPM. This situation could be made worse if the switch to a combined cycle also uses a capital costs for combined cycles that is more consistent with an outlier compared to other independent sources. Choosing a combined cycle as the reference unit under those Net CONE assumptions creates market restrictions that, combined with the recent MOPR elimination, can adversely impact reliability.

3. MULTIPLE FACTORS SUPPORT A COMBUSTION TURBINE

Initial presentations from the Brattle Group indicate that the choice for a reference unit basically comes down to a combustion turbine or a combined cycle. This section describes the reasons for supporting a combustion turbine while the following section addresses considerations that would argue against choosing a combined cycle.

3.1 A combustion turbine represents a pure capacity unit

The RPM was designed to incorporate parameters for a representative unit reflecting the long-run marginal unit for reliability. The entire exercise surrounding the calculation of the CONE and Net CONE for that reference unit attempts to isolate the cost of reliability after revenues for E&AS are removed from the gross CONE.

In PJM, a new combustion turbine is not expected to be dispatched to provide energy very often. According to PJM's estimated dispatch performed as part of the MOPR calculations, combustion turbine units are projected to have capacity factors of around 25 percent compared to the projected capacity factors for combined cycles of around 75 percent.[35]

Given the operating characteristics of existing generation units, combustion turbines generally provide capacity whereas combined cycles also supply energy on a regular basis. As such, combined cycles are not a pure reliability unit. If the goal is to adopt a technology for the reference unit that is closest to a pure reliability offering, combustion turbines would be the appropriate technology to use.

3.2 The Net CONE of a combustion turbine has less uncertainty

A combustion turbine in PJM operates much less than a combined cycle, generating less uncertainty surrounding the value of the Net CONE due to errors in estimating the value of E&AS offsets.

As part of the discussions leading up to their recommendation, the Brattle Group identified a screening criteria pertaining to estimation accuracy. Both energy efficiency and demand response were eliminated due to the "Inability to accurately estimate Net CONE."[36] In addition, Brattle concluded that the gas combined cycle had a higher estimation accuracy than the combustion turbine due to uncertainty around the E&AS offset. This is incorrect.

Although the E&AS offset of a combustion turbine may have greater variability than the E&AS estimate for a combined cycle, the overall impact on Net CONE is smaller for the combustion turbine. The Brattle Group improperly conflates the two.

The E&AS offset faces a greater level of uncertainty given a number of factors occurring in the industry.[37] Energy prices are highly dependent on natural gas prices and characteristics of the generation supply mix. As renewable resources come online, energy prices will become more volatile due to direct impacts on the supply curve on an hour-to-hour basis in addition to increased volatility in natural gas prices due to changing demand. In addition, PJM's already limited ancillary services markets could collapse with the entry of batteries. Therefore, any calculation of Net CONE using current market

[35] PJM August 2020 Worksheet on Net CONE calculations, 20200814-net-cone-values-and-indicative-eas-offset-workbook-supplemental.xls

[36] The Brattle Group, "Fifth Review of the Variable Resource Requirement Curve," Presented to PJM Market Implementation Committee, 10/8/2021, p. 13.

[37] Ibid., p. 14.

conditions will include uncertainty around the true Net CONE for an asset that depends on energy revenues. The impact will be greater for technologies that have a higher E&AS offset.

Uncertainty surrounding the combination of changing fuel prices, dispatch and energy revenues has a greater impact on the Net CONE for combined cycles versus a generation technology such as combustion turbines that operate less frequently. Combustion turbines only operate during peak hours and, due to their higher heat rates and lower dispatch, have a Net CONE that are more immune to changes in average energy prices. Although combustion turbines tend to supply the vast majority of ancillary services,[38] estimates of the E&AS offset is smaller for the combustion turbine than for the combined cycle due to their different capacity factors.

Referring back to **Figure 8**, the Net CONE calculation for a combustion turbine incorporates less uncertainty than that of a combined cycle. First, the capital cost estimates are more consistent across third-party publications (refer back to **Figure 7**). Perhaps more importantly, the highly uncertain and volatile estimates for E&AS offsets are among the lowest levels as a percentage of Gross CONE across the technologies examined by PJM and the Brattle Group. Whereas the E&AS offset is 61% of Gross CONE for a combined cycle, the E&AS offset for a combustion turbine is only 21% of Gross CONE (**Figure 12**).

[38] Monitoring Analytics, "State of the Market Report for PJM: 2020," Volume 2, Detailed Analysis, pp. 481, 490, 493, 2020 State of the Market Report for PJM (monitoringanalytics.com)

Figure 12: PJM Estimated E&AS Offset as a Percentage of Gross CONE[39]

Resource Type	Gross CONE ($/MW-Day)	Average Zonal E&AS Revenue Offset ($/MW-Day)	E&AS as Percentage of Gross CONE
Nuclear	2,000	420	21%
Coal	1,068	36	3%
Combined Cycle	320	195	61%
Combustion Turbine	294	62	21%
Solar PV (Tracking)	290	153	53%
Solar PV (Fixed)	271	94	35%
Onshore Wind	420	203	48%
Offshore Wind	1,155	284	25%
Battery Storage	532	429	81%
Energy Efficiency	644	517	80%
Demand Response (Gen)	254	0	0%

As a result, the impact of changes in market price conditions may have a large relative impact on the E&AS offset for combustion turbines versus combined cycles, but the total impact on Net CONE is lower. The estimated Net CONE for combustion turbines has a higher level of accuracy than the Net CONE for a combined cycle.

The greater potential for error around Net CONE estimates for combined cycles versus combustion turbines can be illustrated using PJM's August 2020 Net CONE calculations. Those calculations include an estimate of the E&AS offset for each zone within PJM, but hold Gross CONE constant. This data illustrates how variability around the E&AS offset is greater for the combustion turbine, but estimates for the Net CONE of a combined cycle are much more variable.

Figure 13 shows the original data and average across all PJM zones. The calculation of the standard deviation (a measure of volatility) and coefficient of variation (standard deviation divided by the average) are added at the bottom. The coefficient of variation measures the relative variability of the estimated E&AS and Net CONE. For the combustion turbine, the coefficient of variation is greater around the E&AS estimate compared to the combined cycle. But, because there is a lower relative value for the E&AS

[39] E&AS offset calculations based on PJM's August 2020 Net CONE values and indicative E&AS Offset workbook: 20200814-net-cone-values-and-indicative-eas-offset-workbook-supplemental
This assumes that the estimate for ancillary services revenues in the E&AS offset for combustion turbines is accurate. In fact, PJM's ancillary services markets are very small and prior estimates have overstated the potential revenues that could be available to a single project.

estimate versus Gross CONE, the coefficient of variation (i.e., standard deviation divided by the mean) on Net CONE for the combustion turbine is much smaller (i.e., 9%) than the coefficient of variation on Net CONE for the combined cycle (i.e., 31%).[40]

Figure 13: PJM E&AS and Net CONE Sensitivity to Market Conditions[41]

Default Zonal Net CONE

All quantities are in $/MW-Day (Nameplate) and Default Net CONE is in $/ICAP-MW-Day

Combustion Turbine				Combined Cycle			
		Gross CONE	$294			Gross CONE	$320
		Net Reactive Service Revenue Offset	$6.02			Net Reactive Service Revenue Offset	$9.18
		Capacity Value (% Nameplate MW)	NA			Capacity Value (% Nameplate MW)	NA
Zone	**Net E&AS* Revenue Offset**	**Net CONE**	**Default Net CONE ($/ICAP MW-Day)**	**Zone**	**Net E&AS* Revenue Offset**	**Net CONE**	**Default Net CONE ($/ICAP MW-Day)**
AECO	$36.72	$251	$251	AECO	$142.70	$168	$168
AEP	$66.47	$222	$222	AEP	$214.72	$96	$96
APS	$86.40	$202	$202	APS	$241.90	$69	$69
ATSI	$72.95	$215	$215	ATSI	$219.98	$91	$91
BGE	$78.23	$210	$210	BGE	$237.39	$73	$73
COMED	$48.17	$240	$240	COMED	$170.74	$140	$140
DAYTON	$71.04	$217	$217	DAYTON	$221.05	$90	$90
DEOK	$77.93	$210	$210	DEOK	$217.30	$94	$94
DOM	$55.57	$232	$232	DOM	$184.01	$127	$127
DPL	$67.10	$221	$221	DPL	$199.12	$112	$112
DUQ	$71.15	$217	$217	DUQ	$212.69	$98	$98
EKPC	$71.00	$217	$217	EKPC	$222.55	$88	$88
JCPL	$36.44	$252	$252	JCPL	$142.05	$169	$169
METED	$58.75	$229	$229	METED	$194.20	$117	$117
PECO	$43.96	$244	$244	PECO	$165.61	$145	$145
PENELEC	$118.00	$170	$170	PENELEC	$270.68	$40	$40
PEPCO	$53.17	$235	$235	PEPCO	$193.41	$117	$117
PPL	$45.01	$243	$243	PPL	$165.97	$145	$145
PSEG	$35.07	$253	$253	PSEG	$140.55	$170	$170
RECO	$38.53	$249	$249	RECO	$144.76	$166	$166
Average	**$62**	**$226**	**$226**	**Average**	**$195**	**$116**	**$116**
Std Dev	**$20**	**$20**	**$20**	**Std Dev**	**$36**	**$36**	**$36**
Std Dev / Average	**33%**	**9%**	**9%**	**Std Dev / Average**	**19%**	**31%**	**31%**

*** Net E&AS Revenue Offset value in tables above does not include reactive services. Reactive services constant is added to Net E&AS to determine Net CONE.**

Therefore, a change in market conditions may impact the E&AS of a combustion turbine at a relatively greater level than the E&AS of a combined cycle, but the smaller E&AS

40 A similar relationship holds in the most recent analysis of MOPR values, 2023-2024 BRA Default MOPR Floor Offer Prices for New Entry Capacity Resources with State Subsidy, $/MW-Day (UCAP Basis), PJM Interconnection LLC, August 2, 2021, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-new-entry-capacity-resource-with-state-subsidy-with-elcc-rules.ashx

41 Based on the Net CONE calculations presented by PJM on August 2020, 20200814-net-cone-values-and-indicative-eas-offset-workbook-supplemental.xls

offset mitigates the ultimate impact on Net CONE. As a result, the Net CONE of a combined cycle is subject to greater uncertainty than the Net CONE of a combustion turbine due to changing market conditions.

The U.S. Court of Appeals agrees with this interpretation of the relative impacts:

> Combined cycle plants are more reliant on energy market revenues to justify construction. Those energy market revenues—included in the EAS Revenue Estimate— are often considered more difficult to estimate than the construction costs that also factor into the net CONE. Accordingly, any mis-estimation of energy market revenues has a larger impact on the accuracy of a combined cycle plant's net CONE than on a combustion turbine plant's.[42]

Given that the value of the Net CONE impacts the RPM parameters, keeping the combustion turbine as the reference unit will result in less uncertainty surrounding projection error than using a combined cycle as the reference unit.

3.3 Nearby markets use a combustion turbine as the reference unit

Both New York and New England use a combustion turbine as the reference unit, albeit with different justifications. Although the characteristics of different regions could, in theory, support different technologies as a reference unit, electricity markets in the northeastern United States are highly interconnected. PJM interconnects directly with the New York ISO and is physically close to ISO-NE via New Jersey and Connecticut. Power flows through each of these markets and all of these markets offer each other capacity support during emergencies and real-time planning coordination. Maintaining the combustion turbine as the reference unit is consistent with surrounding jurisdictions.

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[42] United States Court of Appeals FOR THE DISTRICT OF COLUMBIA CIRCUIT, Argued April 6, 2021, Decided July 9, 2021, No. 20-1212 DELAWARE DIVISION OF THE PUBLIC ADVOCATE, ET AL., PETITIONERS v. FEDERAL ENERGY REGULATORY COMMISSION, RESPONDENT PJM INTERCONNECTION, L.L.C., INTERVENOR On Petition for Review of Orders of the Federal Energy Regulatory Commission, p. 10.
https://www.cadc.uscourts.gov/internet/opinions.nsf/C58F501FCCA3ABCE8525870D0050CBAC/$file/20-1212-1905643.pdf

3.4 Combustion turbines offer greater flexibility, modularity and optionality

Given uncertainty surrounding future market conditions, combustion turbines offer greater modularity and optionality versus the much larger combined cycle configuration. The lower upfront capital cost also is likely to be more attractive to developers who face an uncertain policy life for their plant. Although the market monitor recommends using a 35-year useful life, policy trends and technology developments can be expected to shorten project life dramatically. As already mentioned, adopting this life extension also needs to incorporate the associated capital and financing costs. If the face of this uncertainty, developers are more likely to lean towards lower capital cost projects.

In addition, combustion turbines have lower labor cost requirements compared to combined cycles, and offer a relatively low fixed operating cost commitment going forward.

Lessons learned from regions that already have experienced higher levels of renewable integration is informative. A decade ago, combustion turbines became the resource of choice as renewables started coming online in Texas, followed by more operationally flexible aeroderivatives and reciprocating engines. As renewable policy goals are realized in PJM, combustion turbines could see a resurgence in areas that allow new fossil fuel units to be permitted.

3.5 Any cost estimate for a combustion turbine should reflect industry consensus

PJM's current Gross CONE assumptions are similar to an NREL estimate of combustion turbine costs. NREL has since updated its estimates, but the relative overnight capital cost of combined cycles is still closer to the overnight capital cost of combustion turbines than other estimates. This is an outlier on the lower end of the range provided by other independent resources and should be adjusted to reflect capital cost data adopted through a public process (e.g., Analysis Group CONE estimates for NYISO, Sargent & Lundy's cost estimates adopted by the EIA) and/or vetted through a more robust discussion at PJM. As the overnight capital cost translates directly into the Gross CONE, it is important to use a consensus versus an outlier. Even better would be to eliminate the variability by adopting the combustion turbine which offers consistency and a technology that has a tighter range of publicly-available cost estimates.

Key Insights:
The PJM generation mix is rapidly evolving, multiple technologies are viable, operating characteristics contribute to reliability, and there is no obvious reference resource to which to switch. In PJM, E&AS offsets for combustion turbines are less critical to the calculation of Net CONE, eliminating a source of error compared to technologies that heavily rely on energy revenues (e.g., combined cycles). Given uncertainty surrounding the generation mix, projected E&AS offsets due to the changing generation mix, and absence of a clear alternative to the current reference resources, the capacity market would benefit from stability in maintaining the same reference resource.

4. USING A COMBINED CYCLE IS PROBLEMATIC

This report already has identified some of the problems with the proposed combined cycle calculation:

1) PJM capital costs have been consistent with an outlier cost estimate and are too low compared to updated independent estimates;

2) The E&AS offset is a larger proportion of Gross CONE, resulting in greater uncertainty and error around the Net CONE estimate; and

3) Switching to a dramatically lower cost estimate introduces unnecessary regulatory volatility into RPM prices, can create barriers to entry, and could have adverse consequences for reliability.

If a combined cycle is to be used as the reference unit, there are a number of adjustments to be considered. This section describes issues that need to be addressed before a combined cycle unit could be adopted as the reference unit for the RPM.

4.1 Capital costs should reflect updated estimates and industry consensus

Capital costs for a combined cycle unit should reflect an industry consensus versus outlier, reflect updated estimates in the public domain, and incorporate existing and short -term inflation expectations.

4.2 The assumed combined cycle configuration should be realistic

The combined cycle configuration should reflect the most flexible option available given investor preference for optionality, modularity and flexibility in light of changing market conditions.

4.3 The ancillary services offset should reflect existing and anticipated conditions

The offset for ancillary services should properly reflect the limited demand in PJM for ancillary services given the self-supply for most of the system's needs. Much of PJM's ancillary services are self-supplied by market participants. As a result, there is a limited amount of ancillary services required to be procured through competitive markets.[43] The average interval Tier 1 Synchronized Reserve (MW) procured is only 2,000 MW. It would be unrealistic to assume that a single new entrant would supply a significant amount of those reserves.

In fact, combined cycles supply very little, if any, of the ancillary services procured by PJM (**Figure 14: Percentage of Ancillary Services Provided by Unit/Fuel Type in 2020Figure 14**). In 2020, combined cycles only supplied 11.7% of the Tier 2 Synchronized Reserve and negligible amounts of the nonsynchronized reserves and scheduled DASR. Therefore, there should be negligible or no ancillary services offsets for the assumed combined cycle.

[43] Monitoring Analytics, "State of the Market Report for PJM: 2020," Volume 2, Detailed Analysis, p. 484, 2020 State of the Market Report for PJM (monitoringanalytics.com)

Figure 14: Percentage of Ancillary Services Provided by Unit/Fuel Type in 2020[44]

Generation Technology	Tier 2 Synchronized Reserve		Nonsynchronized Reserve		Scheduled DASR	
	% by MW	% by Credits	% by MW	% by Credits	% by MW	% by Credits
CT – Natural Gas	37.0%	42.1%	50.6%	58.9%	61.7%	51.7%
CT – Oil	12.3%	16.7%	34.6%	31.1%	18.9%	18.2%
DSR	27.8%	11.2%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	11.7%	21.3%	0.0%	0.0%	2.8%	13.0%
Hydro-Run of River	6.4%	3.2%	14.6%	9.9%	0.0%	0.0%
Hydro – Pumped Storage	0.7%	0.6%	0.1%	0.1%	10.3%	3.6%
CT – Other	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	3.6%	4.2%	0.0%	0.0%	5.6%	9.0%
RICE – Natural Gas/Other	0.4%	0.4%	0.0%	0.0%	0.4%	1.4%
Steam – Natural Gas	0.1%	0.3%	0.0%	0.0%	0.3%	1.0%
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

In addition, both quantity and cost of ancillary services that could be provided by combined cycles should reflect anticipated entry of batteries, which are better positioned to provide ancillary services on a more economic basis than fossil fuel units.

4.4 The energy revenue offset should use a projected PJM generation mix

The offset for energy revenues earned by a combined cycle should incorporate:

- **Changing Fuel Mix:** The changing fuel mix on energy prices (e.g., higher integration renewables could increase price volatility due to greater intermittency and may suppress overall prices).

[44] Ibid., pp. 481, 490, 493, 2020 State of the Market Report for PJM (monitoringanalytics.com)

- **Impact on Natural Gas Prices:** The changing fuel mix could impact natural gas prices (e.g., the lower demand for natural gas-fired units could increase fuel price volatility which would impact energy prices).

- **Lower Capacity Factors:** Higher supply of renewables in the generation mix could reduce combined cycle capacity factors.

- **Volatility:** Changing volatility in energy prices could impact merit order, dispatch, and the total energy offset for combined cycles versus coal plants in PJM.

Alternatively, a resource such as a combustion turbine does not face these complications and associated estimation errors associated with the energy offset.

4.5 Location and costs should assume realistic siting and permitting assumptions

The assumed location for a combined cycle reference unit should be in a subzone that allows for combined cycle generation to be built (e.g., consistent with state policies, sufficient natural gas pipeline capacity, near to both gas pipelines and transmission lines with sufficient capacity, and ability to obtain the necessary permits). For states with near-term policy goals (e.g., 2025 – 2032), assume that new fossil fuel units will not be built and adopt a feasible alternative as the reference unit instead.

4.6 The assumed lifespan should reflect realistic economics, technology and policy

The assumed life of a new combined cycle should reflect the achievement of state policy goals and associated economics. For example, a combined cycle sited in a state with a 100 percent RPS policy by 2050 would only have a 25-year or less lifespan, whereas a state with a 100 percent RPS policy by 2040 would only have a 15-year or less lifespan. A long-term economic analysis should be used to ensure that the assumed technical life is feasible given policy goals and changing economics because of those policy goals. In addition, extending the project life of the reference unit also needs to incorporate anticipated capital costs and equipment upgrades, as well as financing costs associated with the extended life.

4.7 A steeper demand curve does not address uncertainty

The RPM assumes a sloped shape for the VRR curve.[45] The slope and shape of this curve is impacted by the choice of reference unit. The starting point for the position of the VRR Curve is where the Net CONE of the reference unit intersects the targeted installed reserve margin requirement. The slope around that point reflects a number of factors including higher value of additional resources beyond the targeted reserve margin, desire to reduce reliability price volatility as market conditions change, and market power mitigation. The shape PJM has adopted reflects tradeoffs between the goal of meeting reserve margin requirements without too much price volatility or excess cost.

Brattle has proposed to change the slope of the VRR curve to address the greater uncertainty associated with Net CONE due to the E&AS adjustments. Such an adjustment presumably would be made if the chosen reference unit is the combined cycle which has been projected to operate frequently in PJM's energy markets. Such a change injects a new rationale for the shape of the VRR Curve, one that is focused on error versus economic theory.

Although details surrounding how the VRR curve would be adjusted has not been disclosed in detail, any change would have to ensure that: 1) there is no other way to adjust for the error or uncertainty; 2) a change to the parameters underlying the VRR curve can be justified; and 3) the proposed change actually addresses the issue of concern. None of the Brattle Group's analysis to date explains these factors.

For example, a steeper demand curve is not needed to adjust for estimation error if the error can be remedied in other ways. If a combustion turbine is used as the reference unit, adjustment to the VRR curve is not required given limited variability around the average Net CONE estimate.

If a combined cycle under the proposed assumptions is adopted, the VRR curve should be steepened only if that adjustment shifts the VRR Curve outwards beyond the intersection of the Net CONE of the reference unit and targeted quantity. PJM has shifted the VRR Curve out beyond the starting point based on the reference unit before. This shift outward

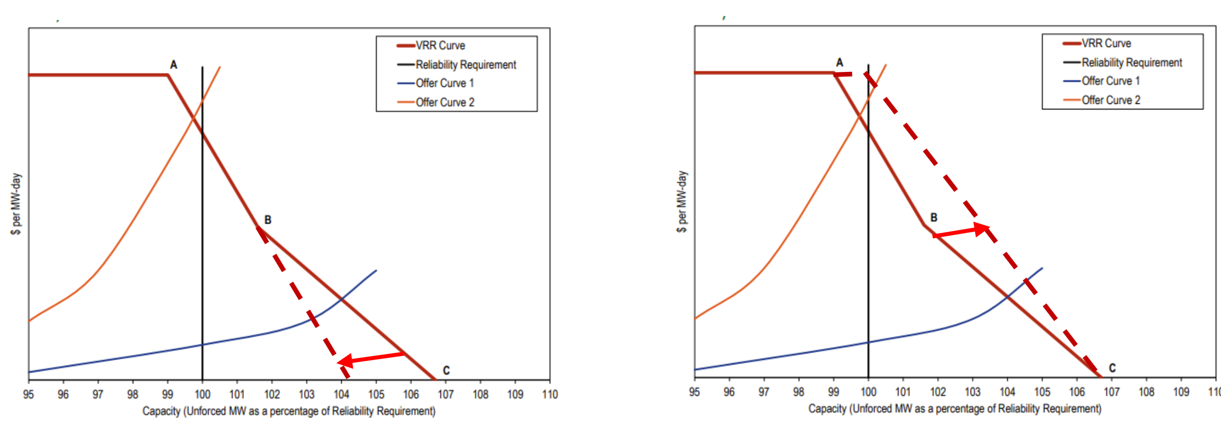
[45] The Brattle Group, "Fifth Review of the Variable Resource Requirement Curve," Presented to PJM Market Implementation Committee, 10/8/2021.

generally increases the amount of capacity procured, something that should be done in the face of uncertain cost estimates to ensure adequate reliability. Making the demand curve steeper around a lower, more uncertain reference unit Net CONE simply compounds the reliability issues created by elimination of the MOPR and should be avoided.

The distinction is illustrated in **Figure 15**. The underlying charts of the VRR curve come from the 2021 Quarterly State of the Market Report for PJM. The red dotted line is added to represent alternative ways to "steepen the VRR curve."

Figure 15: Alternative Ways to Steepen the VRR Curve[46]

Alternative 1 **Alternative 2**



Alternative 1 reflects the steepening that the Brattle Group appears to be considering. Making such an adjustment would reduce the highest MW point to be below the 106.7 percent of the reliability requirement. This adjustment serves to decrease the potential range of quantity procured, but there is no assurance that the more targeted procurement would be achieved. Given that the reliability supply curve with the MOPR elimination looks similar to the blue line, the resulting equilibrium is likely to reduce quantity procured. This is exactly the opposite of what should be done in the face of uncertainty, elimination of the MOPR, and adoption of new reference unit with a much lower Net CONE.

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[46] Monitoring Analytics, LLC, p. 296, [2021 Quarterly State of the Market Report for PM: January through June (monitoringanalytics.com)]

Alternative 2 reflects a different way to "steepen the VRR Curve" and properly account for greater uncertainty. This approach is achieved by maintaining the highest MW point at 106.7 MW, but shifting the starting MW point of the downward sloping demand curve at 100 percent or higher than the reliability requirement. This approach adjusts for the potentially adverse reliability impacts previously discussed, namely bidding barriers, reduced quality of reliability resources and increased unavailability of reliability resources over time. It recognizes that elimination of the MOPR combined with adoption of a combined cycle Net CONE with high potential for error serves to: 1) set the pivot point in the VRR curve too low; and 2) preclude higher quality resources from clearing. By shifting the VRR curve out to the right, and steepening the curve by extending the RPM bid cap outward, additional reliability resources can be procured to mitigate the potential reliability issues.

The problem with both of these approaches is that they are spurious without any justified metric to ensure that the adjustment addresses the concern. A simpler solution is to choose a combustion turbine instead of choosing a combined cycle reference unit. The combined cycle includes so much uncertainty around the Net CONE estimate due to the E&AS offset and unrealistically long economic life. Either the potential for error should be minimized, which is difficult to do in the face of so much market uncertainty, or an alternative reference unit with less potential for error should be chosen. To this end, the combustion turbine is a superior choice for a reference unit as opposed to the more complicated and risky approach of choosing an inaccurately estimated combined cycle and steepening the demand curve.

That said, elimination of the MOPR could inflict a significant change on the RPM bids and "equilibrium" outcome. Renewable resources purchased under state requirements would be able to bid into the auction at whatever price they wish, with no limits to ensure achievement of long-run marginal costs on average over time or competitive market outcomes that send an appropriate price signal. To remedy this situation, PJM can either:

1) **Qualify supply:** Establish a qualification process that ensures availability of reliable resources, perhaps more similar to the orange supply line in the charts (e.g., the ELCC approach being developed); and/or

2) **Increase demand:** Adjust the VRR curve to procure a higher level of reliability resources in recognition of the fact that the average availability on demand of

reliability resources bidding into the market will be reduced and the long-run marginal cost of new entry will not be achieved.

It is possible that a steeper VRR curve similar to Alternative 2 can address some of the potential reliability challenges that would occur with elimination of the MOPR. However, such an adjustment would need to go through a more detailed process tied to justification for changing the parameters of the VRR curve as opposed to simply trying to adjust for a known set of errors introduced into the RPM construct due to an inappropriately estimated reference unit.

Key Insights:
As proposed, the combined cycle is an inappropriate reference unit. There are a number of problems to be addressed before this technology can be adopted as a representation of the long-run marginal cost of new entry. Any adjustment to the shape or slope of the VRR curve to address adoption of the proposed combined cycle as the reference unit is a poor attempt to fix a problematic set of assumptions. Instead of going through the complicated process of developing a more accurate representation of the Net CONE of a combined cycle or steepening the demand curve to address those shortcomings, it would be easier to simply adopt a combustion turbine as the appropriate reference unit.

5. GOING FORWARD, A NEW REFERENCE UNIT MAY BE NEEDED

Competitive markets appear to have reached a tipping point. Throughout the U.S., expansion of clean energy resources supported by state subsidies, consumer preferences, and renewable requirements are reaching levels that can infringe upon the proper functioning of competitive markets designed to procure scarce fossil fuel generation. The situation facing PJM's RPM is no different.

As states within PJM continue to pursue their environmental goals and the costs of those alternatives decline, PJM may need to consider whether something other than a fossil fuel unit is the more appropriate reference unit for a new entrant into PJM markets for the following reasons.

- States within PJM already are passing laws to retire existing fossil fuel units and limit the operation of new units. There are several jurisdictions in PJM in which carbon emitting plants may not be able to receive permits, evidence of which may become more apparent prior to the next VRR reset.[47]

- Although renewables are more likely to be permitted in certain states serviced by PJM, wind and solar are intermittent resources that do not offer the same level of reliability as generators that can provide energy on demand, making them an inappropriate reference unit on a stand-alone basis.

- As technology improves, there are a number of potential alternatives to a large fossil fuel reference unit that could be considered, including a renewable hybrid, more flexible backup generation behind the meter at the distribution level, or a fossil fuel unit with carbon capture may represent the most viable means of adding reliability resources to insure reliability consistent with state policies.

- Although costs are projected to decline, any estimates of Net CONE for alternative reliability resources should reflect actual versus hypothetical cost curve estimates to provide the most certainty surrounding, including:
    - Capital costs
    - Operating characteristics
    - Technical life
    - Location

- Changing market conditions may challenge traditional fossil fuel resources with greater regulatory volatility.

- Given intermittency and uncertainty associated with dispatch of battery storage, the offset for E&AS may need to reflect a value generated using a stochastic approach versus a single forecast.

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[47] Other jurisdictions are rejecting requests to repower fossil fuel units (e.g., New York) and require energy storage to be procured or built for solar energy arrays above 500 kW (e.g., Massachusetts).

Key Insights:
The RPM reference unit and associated parameters may need to be completely reexamined to reflect the transition to a decarbonized grid by the next quadrennial review. In light of that adjustment, which could generate a much higher Net CONE value driven by policy requirements, reliability requirements, and new technologies, it would be dangerous to adopt a different type of fossil fuel unit than the combustion turbine at this time. In particular, choosing to adopt a reference unit that has a Net CONE significantly lower and subject to greater uncertainty than the value of the Net CONE currently being used in PJM's RPM parameters and VRR curve could introduce needless regulatory changes, increase price volatility, create unnecessary noise around the price signal, and create barriers to entry for new technologies.

6. CONCLUSION

PJM is in a state of transition. With more than half of its states pursuing aggressive RPS and carbon emission reduction goals, PJM's generation mix, queue composition, and reliability requirements are starting to follow the path of other regions that already have experienced greater levels of renewable integration.

To this end, lessons learned from those markets are insightful:

1) Manage the market to allow for a smooth transition to clean energy resources.

2) Account for different operating characteristics that can create value.

3) Recognize the shift away from development of extremely large, capital-intensive generation projects to smaller, more modular and flexible projects that are better equipped to meet operational needs in a market that integrates higher levels of renewables.

With respect to choosing an appropriate reference unit during this quadrennial review, there are a number of reasons to support continued use of a combustion turbine as the reference unit. Remaining with this technology mitigates compounding impacts in RPM markets. This type of resource serves as the reference unit in neighboring markets. It represents a pure capacity resource. The potential for error surrounding the Net CONE due to misspecification of the E&AS offset is lower for the combustion turbine than alternatives such as the combined cycle that has a higher capacity factor. Maintaining the existing resource as the reference unit will result in less disruption to a market already undergoing significant upheaval due to changing market rules and generation mix.

Adopting a combined cycle as the appropriate reference unit is problematic for a number of reasons. Uncertainty surrounding the Net CONE is higher due to potential estimation error of both the capital cost and E&AS offset. Given the potential need to adjust the reference unit to reflect state policies pursuing a clean energy future on a zonal basis during this quadrennial review, and the possibility of adjusting the reference unit to reflect these policies at the next quadrennial review, adoption of a combined cycle reference unit would inject needless regulatory volatility into the RPM and could create adverse consequences for reliability.

All of these considerations lead to a recommendation to continue with the combustion turbine as the general PJM reference unit for purposes of setting the RPM parameters at this time.

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