Toward 100% Carbon-Free Electricity

HOW THE REGIONAL ELECTRICITY MARKET CAN EVOLVE TO HELP WASHINGTON, DC ACHIEVE ITS ENERGY AND CLIMATE CHANGE GOALS

PREPARED FOR

District of Columbia Department of Energy and Environment

OCTOBER 2021

DEPARTMENT OF ENERGY & ENVIRONMENT

GOVERNMENT OF THE DISTRICT OF COLUMBIA
MURIEL BOWSER, MAYOR

PRINCIPAL AUTHOR

Brattle Group

PREPARED BY

Kathleen Spees
Travis Carless
Sean Chew

NOTICE

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

© 2021 The Brattle Group

TABLE OF CONTENTS

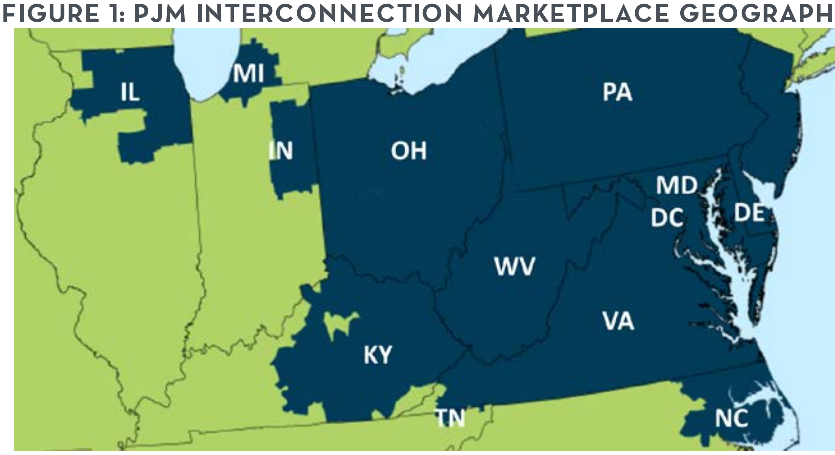
Executive Summary

Washington, DC leads the nation in its commitment to achieve a 100% renewable power supply mix by 2032 and 100% economy-wide greenhouse gas (GHG) neutrality by 2050. The District's Clean Energy DC plan has identified rapid elimination of GHG emissions from the power grid as a central and critical component of its decarbonization strategy.[1] The electricity sector is the source of 55% of total District GHG emissions; reducing these emissions through investments in energy efficiency and renewable power together make up the majority of the emissions reductions anticipated between now and 2032.[2] A 100% clean electricity supply mix is also required to deliver GHG reductions through electrification of transportation and building energy uses.

The broad scope of policy reforms required to achieve 100% clean energy on the District's accelerated timeframe will alter nearly every aspect of how electricity supply is developed, operated, and delivered to the District. The Clean Energy DC plan includes substantial expansion of energy efficiency, demand response, local solar, and other distributed resources. Further, deliveries of power from the bulk system must be fully decarbonized to ensure GHG neutrality.

The District's position within the regional electricity grid presents both opportunities and challenges with respect to achieving rapid and affordable grid decarbonization. The opportunities derive from access to a broad interconnected marketplace operated by PJM Interconnection that connects the District to 13 other states "see Figure 1". This large power market has, for the most part, delivered reliable and affordable power to the District for the past two decades.[3] Access to low-cost power supply at competitive prices has been particularly important for the District, given the limited ability (and high costs) to develop power projects locally.

FIGURE 1: PJM INTERCONNECTION MARKETPLACE GEOGRAPHY



Source and Notes: PJM Interconnection or PJM is the independent entity that operates the power transmission system, schedules power deliveries, and operates the wholesale electricity markets across this regional footprint. PJM Interconnection, Territory Served.

Access to a broad marketplace will become even more important as the District aims to procure large quantities of renewable power to be delivered through the bulk transmission system. The broad regional market creates opportunities to access renewable resources from lower-cost regions; rely on a regionally diverse market to provide

1 See Clean Energy DC Action Plan, August 2018.

2 See: DC DOEE Renewable Energy in the District; Database of State Incentives for Renewables, DC Renewable Portfolio Standard; and DC Public Service Commission, Renewable Energy Portfolio Standard (RPS) Report.

3 PJM estimates that participation in the regional marketplace has delivered \$3.2-4.0 billion per year in cost savings to consumers across its footprint covering 13 states and Washington, DC. These savings arise from the use of competitive market signals to attract investment in the resources needed for summer peak needs and to source energy from the lowest-cost resources available, subject to transmission constraints. See PJM Value Proposition.

balancing services that will compensate for renewable resources' intermittency; and maximize use of the transmission system. Participating in the regional marketplace also offers greater opportunities to coordinate decarbonization policies with other states across the PJM region pursuing their own commitments to clean energy including New Jersey at 100% economy-wide clean energy by 2050, Maryland at 50% renewable by 2040, Delaware at 40% renewable by 2035, Virginia at 100% renewable by 2045/2050, and Illinois at 100% clean energy by 2045.[4]

The transition to a 100% renewable supply mix will also face several challenges in the context of the PJM marketplace. Most fundamentally, the PJM markets have been designed to maintain reliability at least cost, without distinguishing between clean and fossil resources. Without reform, this indifference to GHG emissions and clean energy policy requirements could continue to incentivize market participants to build and operate fossil plants, an outcome that is misaligned with clean energy policy goals. The clean energy transition will require new approaches to maintaining reliability, setting prices, and enabling the participation of emerging technologies. Finally, the wholesale markets must manage amongst the diverse policies of the District and 13 different states, some of which have no renewable or carbon policies.

Seeing both the challenges and opportunities presented by participation in the PJM marketplace, the DC Department of Energy and Environment (DOEE) has posed the following question:

> **Study Question:** How might the PJM electricity markets evolve to help Washington, DC achieve its energy and climate change goals?

This study comes at a unique moment in the evolution of the PJM electricity markets. Several years of debate regarding the conflict between markets and clean energy policies is coming to a conclusion as PJM's proposal to repeal the controversial Minimum Offer Price Rule (MOPR) comes into effect.[5] In 2019, the Federal Energy Regulatory Commission (FERC) ordered PJM to expand the MOPR under the flawed theory that it was needed to maintain reliability and competitive prices in PJM's capacity market.[6] The MOPR was intended to "correct" for the price-suppressive impacts of out-of-market subsidies by restoring capacity market prices to the level that would have prevailed in the absence of the subsidies. The effect of MOPR was to exclude policy-driven resources, such as new renewables developed to meet DC's renewable standard, from clearing in the capacity market. If the MOPR had not been repealed, we estimate that it could have excluded approximately 394 MW of unforced capacity (UCAP) from DC policy resources from clearing the PJM capacity market by 2030, at a cost of approximately $34 million per year to consumers in the District. To mitigate these costs, Washington, DC would also have the option to exit the capacity market entirely under the Fixed Resource Requirement (FRR) alternative, though doing so would introduce a number of risks and forfeit the benefits historically achieved through full capacity market participation. With the repeal of MOPR now in effect, it can be relegated to the status of an unfortunate, but short-lived, detour in the evolution of the wholesale marketplace.

We anticipate that the next phase of electricity market reform efforts will be much more productive. In response to requests from the Organization of PJM States, Inc. and market stakeholders, PJM management and Board of Directors have adopted a strategic priority to "facilitate pursuit of policy-maker and consumer decarbonization objectives by establishing ourselves as a trusted, unbiased policy adviser & driving consensus for at-scale, market-

---

4 See PJM-Environmental Information System "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," and "Landmark Ill. climate bill passes in boon for nuclear, renewables," E&E News Energy Wire.

5 See PJM Interconnection "Revisions to Application of Minimum Offer Price Rule" filed before the Federal Energy Regulatory Commission July 30, 2021 in Docket No. ER 21-2582-000. PJM's proposed repeal has taken effect as of September 29, 2021, though there is a continued possibility of appeal, see Federal Energy Regulatory Commission, Notice of Filing Taking Effect by Operation of Law, September 29, 2021, Docket No. ER21-2582-000.

6 The Reliability Pricing Model (RPM) is PJM's capacity market. The capacity market is a three-year forward market within which PJM procures commitments from enough supply resources (generators, batteries, demand response, and energy efficiency) to ensure that it can reliably meet anticipated peak demand on the system, even after accounting for uncertainties such as weather and resource unavailability.

based solutions where possible."[7] To that end, PJM is supporting a series of stakeholder discussions and market design initiatives aimed at addressing policy priorities and enabling clean energy transition.[8] Supporting reliable, affordable access to the renewable power that will fulfill Washington, DC's 100% renewable power mandate should be incorporated as a priority in these PJM reform efforts given the scale and pace of the District's climate change policy goals.

In this study, we review a range of opportunities for the PJM wholesale markets to evolve to better support and advance the District's policy goals, as oriented to address the following challenges:

- **Redirecting market incentives to achieve policy goals**, rather than maintaining the traditional approach of assuming that the markets must remain indifferent to policy goals,
- **Enabling new technologies** to participate in all markets and support innovative solutions for the clean grid, and
- **Maintaining reliability** as the grid advances from relying primarily on traditional fossil plants to meet energy and other reliability services to one that must rely primarily on intermittent renewables, distributed resources, batteries, and other emerging resource types.

Table 1 provides a summary of reforms that could advance Washington, DC's policy goals; in the body of this report we provide a more comprehensive discussion of each potential reform, how it would support the District's policy goals, and the status of ongoing reform efforts. In some cases, particularly in the context of reliability needs, these reforms are squarely in the purview of PJM to address and implement. However, in many other cases achieving a meaningful solution to support policy goals will require deeper engagement and partnership between PJM and policymakers. For example, the most impactful advances in carbon pricing or regional clean attribute markets would require PJM to develop a regional market framework for coordinating amongst policies, while the District and each state would set the policy parameters to be reflected through the markets. The need for solutions that cross organizational and jurisdictional boundaries could pose a potential barrier to implementation across some of these reforms.

These reforms build on the regional scope and economic principles that have delivered substantial benefits to consumers across the PJM region for many years. Taken as a whole, they represent an ambitious scope that would substantially revise the operations and resource investments governed by the PJM marketplace, redirecting these incentives toward supporting the reliable, affordable, and 100% renewable power supply required by the District. Despite the magnitude and complexity of these reforms, there is urgency to pursue them quickly if they are to provide meaningful support through the District's rapid renewable deployments over the coming decade.

[7] See Organization of PJM States, Inc Letter to PJM, January 8, 2021; and PJM Interconnection, PJM Strategy – Powering Our Future, p. 10.

[8] See PJM Interconnection, Capacity Market Reform Scope: Beyond MOPR, May 13, 2021.

TABLE 1. OPPORTUNITIES TO ADVANCE PJM MARKETS TO SUPPORT CLEAN ENERGY TRANSITION

Challenge	Opportunities to Support Clean Energy Transition
Driving Investments and Operations Toward Cost-Effective Decarbonization	• **Marginal and Total Embedded Emissions Data:** Utilize PJM's granular data of grid operations to address information gaps identified in the Clean Energy DC plan, and provide the District with the high-quality data needed to support policymaking, contracting, GHG accounting, and other market design enhancements • **Regional Clean Energy or Capacity Market:** Introduce a broad PJM-wide marketplace for the procurement of clean energy attributes on behalf of governments, companies, and consumers • **Carbon Pricing:** Review opportunities to achieve carbon reductions through enhanced carbon pricing, such as by addressing carbon "leakage" from the Regional Greenhouse Gas Initiative (RGGI) market, enabling non-RGGI jurisdictions such as the District to express a carbon price (even if there are no local fossil plants), and/or by introducing a PJM-wide carbon pricing mechanism • **Enhanced Clean Attribute Products:** Examine the limitations that the Clean Energy DC plan has identified with the traditional REC product definition, using these as the basis to develop the next generation of REC products that improve accountability and incentives relative to GHG objectives
Enabling Emerging Technologies' Contribution to Grid Transition	• **Fully Enable All Emerging Technologies:** Utilize needs-based, technology-neutral product definitions for all electricity markets. Ensure that all resource types that notionally could provide a certain type of grid service are enabled to do so, are able to participate in price formation/dispatch, and face the minimum possible barriers to entry. Ensure that control room operators have the opportunity to gain experience relying on each emerging resource type to provide essential grid services (even if they are not yet commercially viable) • **Retail Structures:** Even if wholesale markets fully enable distributed resources, additional reforms may be needed in retail rates and retail access rules to accommodate a comprehensive suite of resource types and business models
Maintaining Reliability in the Transition to a 100% Clean Energy Grid	• **Ancillary Service Reforms:** Analyze the need for new types or greater quantities of operating reserves or other grid reliability services to maintain operational reliability as the grid becomes more dependent on renewables, batteries, demand response, and distributed resources • **Energy and Ancillary Price Formation:** Continue reforms aimed at supporting efficient price formation that properly values balancing services and fully integrates emerging resources into price formation (thus limiting or preventing out-of-market reliance on fossil resources) • **Accuracy of Supply and Demand Accounting for Reliability Needs**: Use effective load carrying capability (ELCC) or similar approaches to accurately measure reliability contribution of all resources including intermittent, energy-limited, and fuel-supply-constrained resources; ensure that PJM and distribution utility load forecasts fully reflect demand side resources such as energy efficiency, distributed generation, energy storage, and updated building codes • **Flexible Capacity Requirements:** If the above reforms would not provide sufficient assurance that resources will be available to meet system flexibility needs, consider adopting flexible capacity requirements • **Seasonal Capacity Market Design:** Assess winter reliability needs and enhance seasonal capacity market to fully enable and remunerate seasonal resources

Acronyms and Glossary

BRA	**Base Residual Auction.** The annual auction conducted by PJM to procure capacity supply.
CEAC	**Clean Energy Attribute Credit.** The attribute of a resource being a clean energy resource (whether renewable or nuclear) that can be unbundled and separately sold to signify the production of 1 MWh of clean energy produced.
DER	**Distributed Energy Resources.** Electricity resources located at distributed locations within the electric distribution system.
DOEE	**Department of Energy and Environment.** Agency responsible for administration and oversight of energy and environmental programs in the District.
DSO	**Distribution System Operator.** Under one proposed model for the industry, the DSO would be the entity responsible for scheduling the operations of DERs.
ELCC	**Effective Load Carrying Capability.** The statistically-estimated reliable quantity of capacity that can be delivered by a certain resource type such as renewables or batteries, after accounting for factors including weather, resource variability, and correlations with consumption patterns.
FCEM	**Forward Clean Energy Market.** A proposed regional marketplace for large-scale procurement of clean power supply resources.
FERC	**Federal Energy Regulatory Commission.** The US Federal government agency responsible for the regulation of inter-regional energy markets, including the PJM regional marketplace.
FIT	**Feed-in-Tariff.** A policy incentive for clean energy resources awarded based on the quantity of energy produced.
FRR	**Fixed Resource Requirement.** A rule within the PJM capacity market that allows some utilities or policymakers to exit from the capacity market and procure their own capacity supply needs.
GHG	**Greenhouse Gas.** Air pollutants that increase the net level of heat absorbed and retained by the atmosphere, thus contributing to the greenhouse effect and climate change.
ICCM	**Integrated Clean Capacity Market.** A proposed regional marketplace for procurement of both capacity needs and large-scale clean power supply needs.
IMM	**Independent Market Monitor.** An independent entity responsible for reviewing the competitiveness and efficiency of the wholesale electricity market, and reporting findings to the public and government authorities.
ISO	**Independent System Operator.** An entity such as PJM responsible for scheduling the transmission system and operating regional markets (used synonymously with RTO).
kW	**Kilowatt.** A unit of power consumption or production, equal to 1/1000th of one MW.
LDA	**Locational Deliverability Area.** A pricing zone within the PJM capacity market.
LME	**Locational Marginal Emissions.** The incremental air pollution emissions caused by consuming additional energy (or avoided by producing additional energy) at a given place in the grid at a given point in time, in units of tons per MWh.
LSE	**Load Serving Entity.** Entity that is financially responsible for paying PJM for power on behalf of end-use customers, usually a retail electricity provider or regulated utility.
MAAC	**Mid-Atlantic Area Council.** A region of the PJM capacity market spanning across the District, Maryland, Delaware, New Jersey, and portions of Pennsylvania.
MOPR	**Minimum Offer Price Rule.** A rule within PJM's capacity market that can in some cases require that a capacity resource offer its supply only at or above a defined price level.
MW	**Megawatt.** A unit of power consumption or production, equal to 1000 kW.
MWh	**Megawatt Hours.** A unit of energy consumption or production, equal to 1 MW continuously produced for one hour.

ORDC	**Operating Reserve Demand Curve.** A representation of the ISO's willingness to pay to procure operating reserves, or standby power, to maintain readiness and availability to respond to system emergencies and manage variability in net demand.
PEPCO	**Potomac Electric Power Company.** The distribution utility serving the District of Columbia.
PJM	**PJM Interconnection.** The RTO responsible for scheduling the transmission system and operating the regional wholesale markets serving the District and all or parts of 13 states.
PTC	**Production Tax Credit.** A federal tax incentive awarded to renewable resources.
REC	**Renewable Energy Credit.** A clean energy attribute produced from a renewable supply resource.
RGGI	**Regional Greenhouse Gas Initiative.** An organization that operations a regional cap-and-trade program that limits emissions from power plants within Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia.
RPM	**Reliability Pricing Model.** PJM's capacity market.
RPS	**Renewable Portfolio Standard.** A law requiring that a certain percentage of all power delivered to consumers must be produced by qualified renewable power supply.
RTO	**Regional Transmission Organization.** An entity such as PJM responsible for scheduling the transmission system and operating regional markets (used synonymously with ISO).
SWMAAC	**South West Mid-Atlantic Area Council.** A region of the PJM service territory that includes the District and portions of Maryland.
UCAP	**Unforced Capacity.** The capacity value of a resource after accounting for expected unavailability.
VRR	**Variable Resource Requirement.** The administrative demand curve within the PJM capacity market.
ZEC	**Zero Emissions Credit.** A clean energy attribute produced from a nuclear power plant.

I. Background

The Government of the District of Columbia has put forward the most ambitious clean energy goal in the US. Effective March 22, 2019, the Clean Energy DC Omnibus Amendments Act of 2018 increased the District's Renewable Portfolio Standard from 50% to 100% by 2032, enabling DC to become the first state, district, or territory in the US to achieve a 100% RPS. However, the District's power deliveries are coordinated by the PJM Interconnection (PJM) wholesale power market, which has historically prioritized providing low-cost, reliable generation without consideration for policy resources intended to reduce carbon emissions.

While a low-cost, high reliability approach suited the needs of Washington, DC in the past, maintaining the indifference to carbon emissions may become increasingly at odds with Washington, DC's goals for a clean energy future. For example, PJM wholesale market incentives, have attracted large-scale investments in over 35,000 MW of new natural gas-fired plants into the PJM region since the 2015/16 delivery year, while at the same time providing insufficient incentives to attract new renewable supply or to retain some nuclear resources.[9] This pattern of market-driven investments and retirements is not consistent with a least-cost pathway to meeting the District and states' clean energy goals. The task in this study is to briefly describe the impacts of the now-repealed MOPR on the District's ratepayers, review the challenges in the wholesale markets that may be posed through the District's expedited transition to a renewable supply mix, and examine opportunities for changing the market design to better support this transition.

A. The District's Climate Change Policy Goals

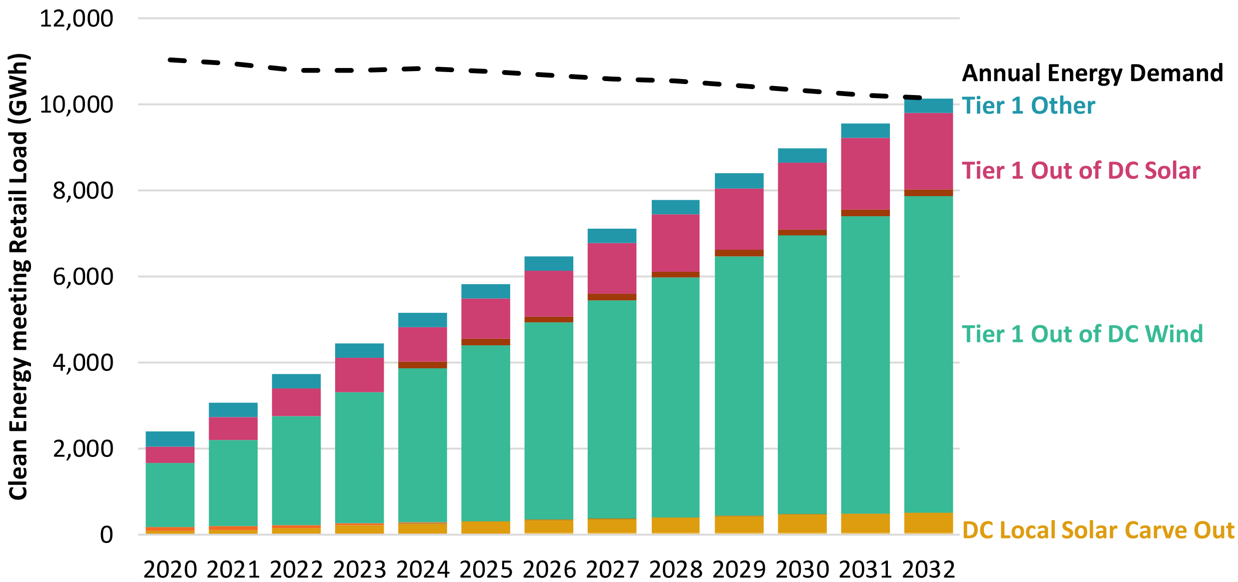
The District of Columbia has set an ambitious mandate of shifting its supply of electricity to 100% renewables by 2032. The District enacted its first RPS in 2005 with subsequent legislation increasing the RPS to 20% by 2020 under the Clean and Affordable Energy Act of 2008, to 50% by 2032 under the Renewable Portfolio Standard Expansion Amendment Act of 2016, and finally to 100% by 2032 under the Clean Energy DC Omnibus Amendment Act of 2018. In most recent legislation, the Clean Energy DC Omnibus Amendment Act of 2018 includes provisions that increase the RPS requirement to 100% from Tier 1 resources, and increase the solar energy carve-out to 5.5% by 2032 and 10% by 2041.[10] Figure 2 summarizes the generation mix of renewable resources that are likely to contribute to the District's RPS requirement of 100% and a 5.5% solar carve out by 2032.[11]

9 PJM Interconnection, L.L.C., "2022/2023 RPM Base Residual Auction Results," Table 8.

10 Tier 1 resources include solar, wind, biomass, methane, geothermal, ocean, fuel cell, and wastewater used as heat source or sink resources. The legislation requires renewable energy to originate from the PJM region, though existing renewable resources outside of the PJM region that have been certified for the RPS program will remain eligible until January 1, 2029. "Renewable Energy Portfolio Standards: A Report for Compliance Year 2020," Public Service Commission of the District of Columbia, May 3, 2021.

11 Note the solar carve out increases to 10% in 2041, as reported in D.C. Law 22-257, "CleanEnergy DC Omnibus Amendment Act of 2018", April 30 2021.

FIGURE 2: CLEAN GENERATION TO MEET THE DISTRICT RPS BY 2032



Sources and Notes: Annual Energy Demand is based on available 2019 historical retail load from Form EIA-861, with projections based on PJM's Load Forecast Report, January 2020, Table E-1. Clean Energy Mandates reflect D.C. Law 22-257, CleanEnergy DC Omnibus Amendment Act of 2018, compiled from PJM Environmental Information Services, "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," April 30, 2021. Proportion of clean energy generation used to meet annual RPS requirements are based on historical proportion of RECs retired as reported by the Public Service Commission of District of Columbia, "Renewable Energy Portfolio Standards: A Report for Compliance Year 2019," April 30, 2021.

B. Overview of Wholesale Electricity Markets

Retail markets involve the sales of electricity to consumers, while ***wholesale markets*** typically involve the sales of electricity among electric utilities and electricity traders before it is eventually sold to consumers. Much of the wholesale market relies upon competitive market forces to set prices, while other prices are based on the service provider's cost of service. FERC authorizes jurisdictional entities to sell at market-based rates, or reviews and authorizes cost-based rates. In competitive markets, prices reflect the factors driving supply and demand – the physical fundamentals. Where rates are set based on costs, market fundamentals matter as well because changes in supply and demand will affect consumers by influencing the cost and reliability of electricity. Supply incorporates generation and transmission, which must be adequate to meet all customers' demand simultaneously, instantaneously and reliably. Consequently, key supply factors that affect power prices include fuel costs, capital costs, transmission capacity and constraints, and the operating characteristics of power plants. Likewise, changes in demand can affect prices. An example of this interaction is serving peak load on a hot summer day where less-efficient, more-expensive power plants must be activated and consequently drive-up prices.

Power pools are multilateral arrangements with members ceding operational control over their generating units and transmission facilities to a common operator. Members provide incremental cost data about their units and system status data to the operator. The operator then runs an energy management system that uses the unit cost data to optimize the overall unit commitment and economic dispatch.[12]

[12] Adapted from FERC's *Energy Primer*, published April 2020.

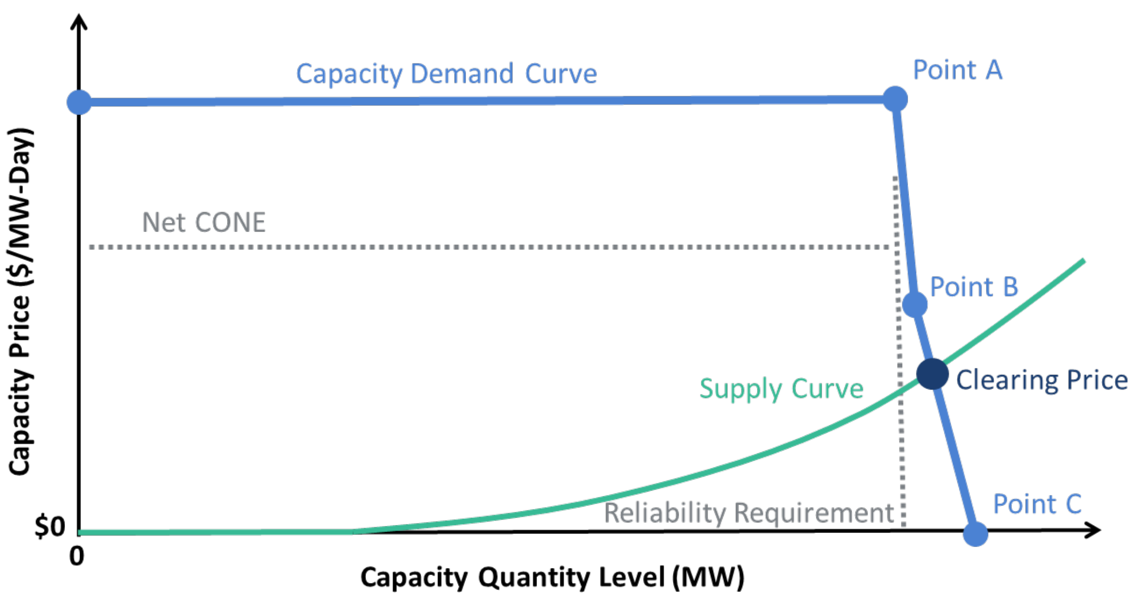
C. Interactions Between Regional Markets and Clean Energy Policies

The generation portion of Washington, DC customer electricity bills reflects competitive wholesale market prices, primarily for energy, but also for ancillary services, and capacity. The ***energy market*** is conducted on a day-ahead and real-time basis, using a region-wide optimization to determine the lowest-cost resources that should be utilized to produce and deliver energy to consumers, subject to transmission constraints. Prices are set, and re-set, every five minutes across approximately 10,000 distinct points in the transmission grid that reflects the incremental cost of meeting electricity needs at each location and each point in time. This granular approach to pricing and resource optimization is becoming increasingly valuable in the context of increasing renewable resource development, as it provides the ability to effectively manage the uncertainties and variability associated with wind and solar energy production.

The ***ancillary services*** markets procure a suite of market products utilized to manage additional grid reliability and balancing needs, beyond what can be supported in the energy market alone. One category of ancillary services, contingency reserves, represent a set of resources that must stand ready to quickly turn on or ramp up in their power output in response to sudden unexpected power plant or transmission outages. Another type, regulation reserves, are tasked with continuously reacting to small imbalances in supply and demand on a granular timeframe below the 5-minute timeframe of the energy market. Together, these markets contribute only a small fraction of the total cost of producing electricity, but nevertheless have a major role in ensuring system reliability and have a substantial influence on price formation and resource incentives.

PJM's ***capacity market*** is a centralized competitive auction mechanism for ensuring adequate electricity supply regionally and by location across the PJM footprint. The Base Residual Auction (BRA) is conducted three years prior to delivery and procures enough capacity resources to meet the Reliability Requirements (or projected peak demand plus an uncertainty reserve margin), using an administrative demand curve to express the willingness to pay for capacity at and above the requirement as illustrated in Figure 3. Generation, demand response, and storage resources across PJM offer their qualified capacity at a price, with these offers aggregated into a resource supply curve. Then the auction selects the lowest-cost resources to take on a capacity supply obligation in exchange for a payment at the auction clearing price. Three years later, in the delivery period, the costs of capacity procurements are allocated to load-serving entities (LSEs) and passed along to customers in proportion to their peak electricity consumption. See the Appendix for a more complete discussion of the capacity market design.

FIGURE 3: ILLUSTRATIVE PJM CAPACITY SUPPLY AND DEMAND CURVES



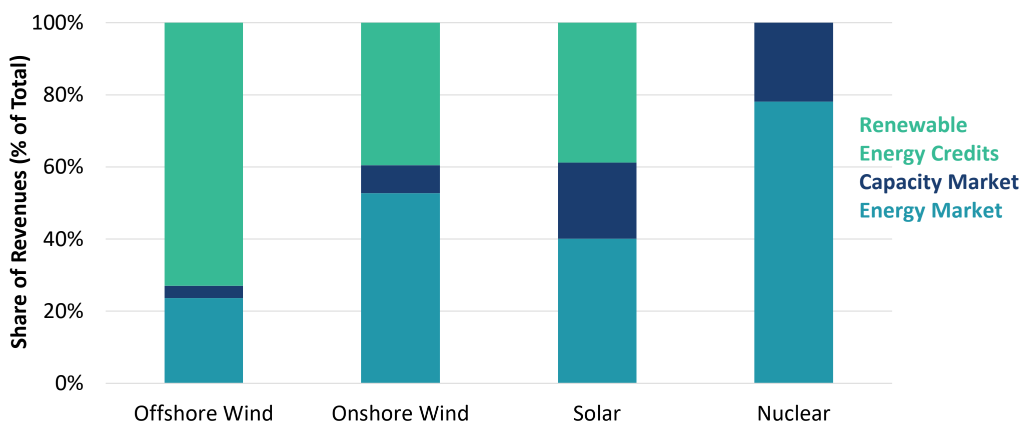
Notes: Illustrative, not drawn to scale. *See* 2022/2023 RPM Base Residual Auction Planning Parameters for specific demand curve parameters.

These three types of PJM markets are all derived from an overarching design objective: to meet consumers' energy needs reliably at the lowest possible cost. Though the markets operate at different timescales to meet different types of reliability requirements, they all provide a signal that reflects system needs and aim to fulfill that need at the lowest possible cost. The markets further incorporate the aim to enable all resources and suppliers to compete on a level playing field to serve these defined system needs. Together, the revenues that a generator, demand response provider, or battery resource could earn from these markets determine the total incentive to invest in a certain technology type and so will shape the mix of resources toward those that offer the most value to the system as a whole.

The District and 10 of 13 PJM states have established RPS programs to support clean energy goals; four (soon to be five) states are members of the Regional Greenhouse Gas Initiative (RGGI) carbon cap-and-trade market.[13] These policy mandates are not directly reflected within the PJM markets, but there are strong interactions between these policy structures and the interconnected regional marketplace.

Although much more is needed to fully decarbonize the power supply, it should be noted that the broad PJM market already offers a number of benefits that can be built upon for enabling grid transition. Wholesale electricity markets provide a ready marketplace where clean energy resources can sell energy, capacity, and (if relevant) ancillary services at a fair price. A share or even the majority of the resources' investment costs can be paid for through participating in the wholesale markets, thus reducing the net cost of clean energy policy programs. For example, Figure 4 illustrates the approximate share of total resource revenues that various clean energy resources earn from the wholesale capacity and energy markets. Offshore wind, onshore wind, and solar earn anywhere from 20% to 60% of their revenues from the wholesale markets, thus requiring customers to pay only the remainder through RECs as incremental costs for pursuing clean energy goals. Amongst clean energy resources, the wholesale markets can also provide signals for the most opportunistic location to site the renewable supply and shift incentives toward renewables that have more capacity/reliability value (as long as policy and contract structures expose the sellers to these wholesale market incentives).

FIGURE 4: REVENUE STREAMS AVAILABLE TO CLEAN ENERGY RESOURCES



Sources and Notes: Approximate revenue streams informed by data in "2022-2023 BRA Default MOPR Floor Offer Prices for New Entry Capacity Resources with State Subsidy," PJM Interconnection, and "CONE and ACR Values – Preliminary," Monitoring Analytics, accessed February 9, 2021.

The wholesale markets further offer balancing services to complement the output profiles of intermittent resources and maintain reliability, creating opportunities to integrate higher volumes of renewables even under a traditional design (though reforms will be needed to support the current pace of transition).[14] The "network access" approach

[13] "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," Environmental Information Services, PJM Interconnection LLC, August 2020. RGGI states include VA, MD, DE, NJ, and soon PA. RPS programs include 52.5×2030 NJ; 52.5×2030 MD; 100×2032 DC; 18×2020 PA; 40×2035 DE; 50x2040 IL; 8.5×2026 OH; 12.5×2021 NC; 15×2021 MI; 100x2045/50 VA; 10×2025 IN; none in WV, KY, TN. Most states have additional clean energy policy support programs beyond RPS including for GHG reductions, or support for nuclear, battery, DR, EE or other clean energy resources.

[14] See PJM Interconnection, "Reliability & Renewable Integration Study," May 4, 2021.

to ensuring transmission sufficiency ensures that clean energy resources across the PJM system are simultaneously deliverable to load centers. The District and several states including Maryland, Delaware, and New Jersey allow RECs to be purchased across state lines to help meet their clean energy goals and access lower-cost clean energy.[15] For states participating in RGGI, the carbon prices imposed on fossil fuel resources are incorporated into the supply cost considered by PJM, making higher-emitting resources appear more expensive, causing them to operate less and reduce their emissions. These features of the broad regional marketplace can substantially reduce the costs of meeting decarbonization goals, particularly where the markets and policy structures are designed in complementary ways.

State policies to support clean energy resources also impact the wholesale markets, primarily by displacing fossil resources and driving lower prices in the energy and capacity markets. Most clean energy resources have zero variable or fuel cost and so offer into the energy market at a zero or negative price, thus incrementally reducing wholesale energy prices. In the capacity market, additions of clean energy resources also tend to reduce capacity prices and displace other types of supply. Renewable resources do not displace fossil capacity on a one-for-one MW basis, however. They tend to have lower capacity ratings, given their intermittency and lower average availability to meet peak system needs.[16]

D. Challenges Anticipated in Clean Energy Transition

The rules of PJM and other regions' power markets were developed at a time when the resource mix was dominated by large central power stations, fossil fuel resources, and when state clean energy goals were modest. Consequently, to some extent, the market design is a product of the assumptions and resource mix relevant at that time, many of which are no longer valid.

> Power markets were developed at a time when the system was dominated by large, central power systems. To some extent, the current market design is a product of the assumptions and resource mix at the time, but that are no longer relevant.

Looking ahead, a new market design aligned with a decarbonized energy grid would assume that clean energy resources including renewables, distributed generation, batteries, nuclear, hydro, and demand response will increasingly dominate the resource mix. Consumers and PJM must be able to rely on these emerging resources to fulfill increasing shares and eventually 100% of all reliability needs, at least within those sub-regions serving jurisdictions that choose to adopt 100% clean electricity mandates. A market designed in alignment with this future could still use many features of the current PJM marketplace, including the approach to rely on technology-neutral product designs, competitive markets for procuring the needed reliability and energy products, minimizing barriers to entry, maintaining transparency in market parameters and pricing, and robust monitoring and mitigation.

However, many other aspects of the capacity market and other wholesale power markets may need to evolve to match the needs of the grid in transition, including:

- **Redirecting market incentives to achieve policy goals**, rather than maintaining the traditional approach of assuming that the markets must remain indifferent to policy goals,
- **Enabling new technologies** to participate in all markets so as to support innovative solutions for the clean grid, and

15 "State RPS Fulfillment," Monitoring Analytics, October 2019.

16 The capacity value of intermittent and energy limited resources tends to decline further as penetration levels of a particular resource type grows. See, for example, PJM Interconnection "How Effective Load Carrying Capability ("ELCC") Accreditation Works," April 20, 2021.

- **Re-evaluating and refining reliability needs** in consideration of a different anticipated set of resource capabilities, system uncertainties, and resource mix that will be available to serve these reliability needs.

Policymakers and customers demand the clean power grid needed to address the crisis of climate change. The transition to a clean energy future must happen, and will happen, with or without a working wholesale power market. But the transition to clean energy can be faster, better, more reliable, and more affordable if the power markets are reformed to focus incentives toward achieving policy goals.

II. The Minimum Offer Price Rule

The PJM Minimum Offer Price Rule (MOPR) has been the focus of a contentious debate across the PJM region for several years, escalating to an unsustainable point in December 2019 when the FERC ordered PJM to expand the rule so expansively as to exclude essentially all new (and some existing) clean policy resources from participation in the PJM capacity market.[17] Anticipating excess costs and interference with achieving their policy goals, commissions, legislators, and other policymakers across the footprint expressed intent to exit the PJM capacity market if the rule were not repealed.[18] This study was initiated, in part, as a means to inform Washington, DC policymakers about the potential costs of MOPR and describe the process that would be utilized if the District would choose to exit the PJM capacity market under the Fixed Resource Requirement (FRR). We find that if the MOPR were kept in place it could apply to approximately 394 UCAP MW of the District's policy resources by 2030, imposing approximately $34 million per year in excess costs on electricity consumers in the District. Exiting the PJM market under FRR in concept could be utilized to mitigate these costs, but would pose implementation risks and result in the loss of economic benefits from participating in the regional PJM marketplace.

As of September 2021, the expansive MOPR has been repealed.[19] The revised MOPR approach relegates the rule to a much narrower role designed to address instances of intentional market manipulation (not to interfere with or undo the effects of policy mandates).[20] The repeal is in effect as of the 2023/24 capacity auction.

A. History and Status of the Minimum Offer Price Rule

Originally, the MOPR was designed as a mechanism to protect the capacity market from the exercise of buyer-side market power. Specifically, schemes where large net buyers or their contractual counterparties could offer a small amount of uneconomic supply into the market below cost in order to artificially suppress market-clearing prices.[21] By taking a loss on that small sell position, a large net buyer could then benefit from low prices on a much larger buy-side position in the market. The MOPR was originally intended to ensure that entities with the incentive and ability to engage in manipulative price suppression would be unable to do so by requiring their capacity market offers to reflect their full costs. Uneconomic new resources sponsored by large net buyers would fail to clear (or would set the prices at a higher level) and prevent the entity from achieving the benefits of manipulative price suppression.

17 *Calpine Corporation et al. v. PJM Interconnection, L.L.C*, 169 FERC ¶ 61,239 (December 19, 2019).

18 The utility serving most of Virginia's demand did exit the capacity market via FRR, and formal investigations of exiting via FRR have been pursued in Maryland, New Jersey, and Illinois. See also See PJM Interconnection, Revisions to Application of Minimum Offer Price Rule, filed before the Federal Energy Regulatory Commission July 30, 2021, Docket No. ER21-2582-000, pp. 12-13.

19 See PJM Interconnection "Revisions to Application of Minimum Offer Price Rule" filed before the Federal Energy Regulatory Commission July 30, 2021 in Docket No. ER 21-2582-000. PJM's proposed repeal has taken effect as of September 29, 2021, though there is a continued possibility of appeal, see Federal Energy Regulatory Commission, Notice of Filing Taking Effect by Operation of Law, September 29, 2021, Docket No. ER21-2582-000.

20 See PJM Interconnection, Revisions to Application of Minimum Offer Price Rule, filed before the Federal Energy Regulatory Commission July 30, 2021, Docket No. ER21-2582-000.

21 A "net" buyer is one whose purchases are larger than their sales. If an entity has a large net buyer position, they would have the incentive to suppress capacity prices in order to secure power at lower total costs.

Symmetrical rules are imposed on large net sellers of capacity in order to prevent them from exercising economic or physical withholding.

In December 2019, the FERC issued an order expanding the scope of MOPR to apply to new or existing resources that receive state subsides, such as RECs and zero emissions credits (ZECs).[22] Exemptions would apply only to existing resources that have previously cleared an auction or new resources that had an interconnection agreement prior to the December 2019 order. The rationale for the expanded MOPR was accepted by the FERC as of the December 2019 order. At the time, the FERC's rationale for having expanded MOPR to policy-supported resources was to "protect" prices in the competitive market from being suppressed by state-sponsored resource planning decisions. State policy support will tend to attract incremental clean energy supply, displace generation that would otherwise be built (or allow additional aging plants to retire), and reduce prevailing capacity market prices. Under the FERC's theory as of the December 2019 order, these lower prices amount to an artificial suppression of market prices; applying an expanded MOPR "corrects" market prices to the higher level that would prevail absent states' policies.[23]

The theory utilized to advance the expanded MOPR is based on faulty economics and inconsistent logic. Instead, state policies aim to address the market's failure to recognize environmental externalities, such as carbon and other air pollutants emitted in the production of electricity. Renewable energy credits and other forms of support for carbon-free generation technologies is a rational attempt to recognize the value of the environmental externalities.[24] While the policy support these resources receive does reduce their net cost of providing capacity, the intent of clean energy incentives is not to affect wholesale market prices, but to incent the transition to cleaner sources of electricity. The "competitive" cost of providing capacity for these policy resources can be low, or even zero, as they are primarily developed for other reasons other than for earning capacity payments. Imposing a price floor on such resources and ignoring the capacity value they provide distorts the market, rather than correcting it. Excluding policy resources causes the market to procure more capacity than needed and improperly raises prices above the level corresponding to actual supply and demand conditions.

Figure 5 illustrates the impact of MOPR on the ability of policy resources to clear the capacity market. The "No MOPR" scenario on the left illustrates clearing outcomes if all capacity resources are allowed to offer at their preferred offer price. Many policy resources would prefer offer at a near-zero price, especially if they would be developed regardless of the capacity revenues they receive. Fossil plants and other capacity resources' competitive offer prices would typically reflect the payments needed to cover their net avoidable going-forward costs (that is, economic costs they will incur as a result of providing capacity in the delivery year that they would not otherwise incur). Clearing prices are set at the intersection of supply and demand, as illustrated on the left panel of Figure 5.

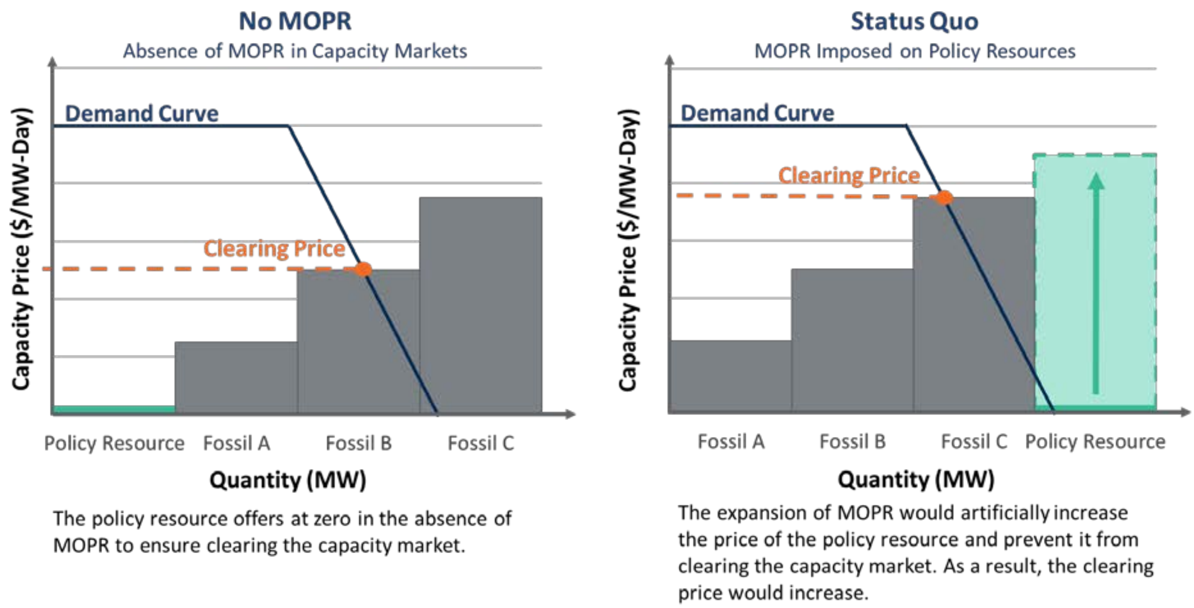
The right-hand panel, however, illustrates the application of MOPR to a policy resource. The MOPR raises the offer price of the policy resource relative to the No MOPR scenario and reorders the capacity market offer supply curve. As the MOPR level exceeds the capacity clearing price, the policy resource does not clear, and the market's incremental capacity need is met by fossil resource C at higher price.

22 Federal Energy Regulatory Commission (FERC), "*Calpine Corporation et al. v. PJM Interconnection, L.L.C.*, Order Establishing Just and Reasonable Rate," 169 FERC ¶ 61,239 (issued December 19, 2019).

23 *Calpine Corporation et al. v. PJM Interconnection, L.L.C*, 169 FERC ¶ 61,239 (December 19, 2019).

24 For a comprehensive discussion of the uneconomic basis of the MOPR, see Spees and Newell, "The Economic Impacts of Buyer-Side Mitigation in New York ISO Capacity Market," filed before the Federal Energy Regulatory Commission on November 18, 2020, Docket No. EL21-7-000.

FIGURE 5: IMPACT OF MOPR TO EXCLUDE POLICY RESOURCES AND INCREASE CAPACITY MARKET PRICES



Overall, applying MOPR to policy-supported resources in the District can be expected to lead to the following undesirable effects:

- Limiting the ability for clean energy resources to generate revenue and interfere with the District's 100% by 2032 RPS.
- Retaining uneconomic high volumes of capacity supply that is unnecessary for reliability.
- Hinder the District's transition to relying entirely on renewable resources by retaining aging fossil plants within the capacity market.
- Causing higher market clearing prices exceeding the level corresponding to actual supply conditions and causing a large wealth transfer from customers to incumbent suppliers.
- Driving an unsustainable market as these distortions become larger over time under the District's statutory mandate to achieve 100% renewable electricity by 2032.

All of these challenges are amplified by the fact that several other states across the PJM region have made similarly strong commitments to clean energy including New Jersey at 100% clean by 2050, Maryland at 100% clean by 2040, Virginia at 100% renewable by 2045/2050, and Illinois at 100% clean energy by 2045.[25] The expanded MOPR ruling initiated extensive rehearing requests and compliance filings. As a result, there have been significant delays to the PJM capacity auction schedule; the planning year 2022/23 auction that was originally scheduled for spring 2019 was rescheduled for mid-2021[26] Auctions for the subsequent planning years will be conducted on a compressed schedule approximately every six months until the market resumes its normal schedule with a May

[25] See PJM-Environmental Information System "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," and "Landmark Ill. climate bill passes in boon for nuclear, renewables," E&E News Energy Wire.

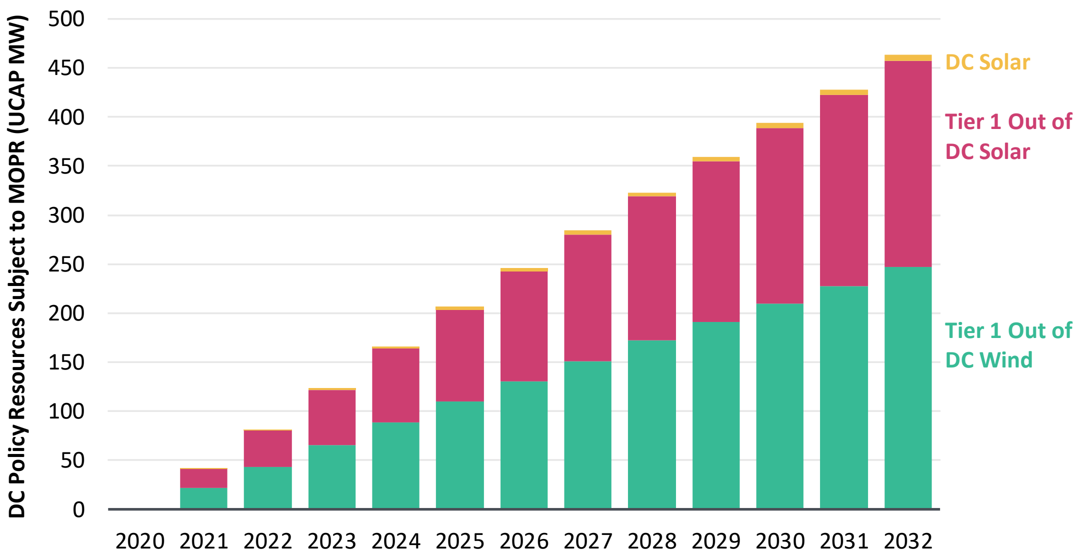
[26] *See* the PJM capacity market schedule in Pete Langbein, "Update on Base Residual Auction Schedule," PJM Interconnection, L.L.C., November 19, 2020.

2024 auction for the delivery year 2027/28. As of last month, PJM's proposal to repeal MOPR has taken effect, so these uneconomic outcomes will be eliminated from the PJM markets prior to the 2023/24 capacity auction.[27]

B. Implications for the District

The 2019 MOPR expansion ordered by the FERC imposes an offer price floor on new resources that could gain policy support or utility investments within District of Columbia. Specifically, subsidized resources that either did not clear the BRA previously or signed interconnection agreements after the order are subject to the MOPR. Because the District set ambitious RPS targets by 2032, a large volume of resources will need to be developed to meet these needs and thus would be subject to the MOPR as summarized in Figure 6. Note that the quantity of resources subject to MOPR is reported in units of derated UCAP MW that are used within the capacity market, a value that is substantially below the nameplate capacity rating of the resources that will be needed to meet the District's renewable mandates. The majority of in-city solar resources used to meet the solar carve out will not be subject to MOPR, because they are accounted for as demand reductions (rather than supply resources) and so are not individually tracked or mitigated in the capacity market.

FIGURE 6: DISTRICT OF COLUMBIA POLICY RESOURCES AT RISK OF NOT CLEARING BECAUSE OF MOPR

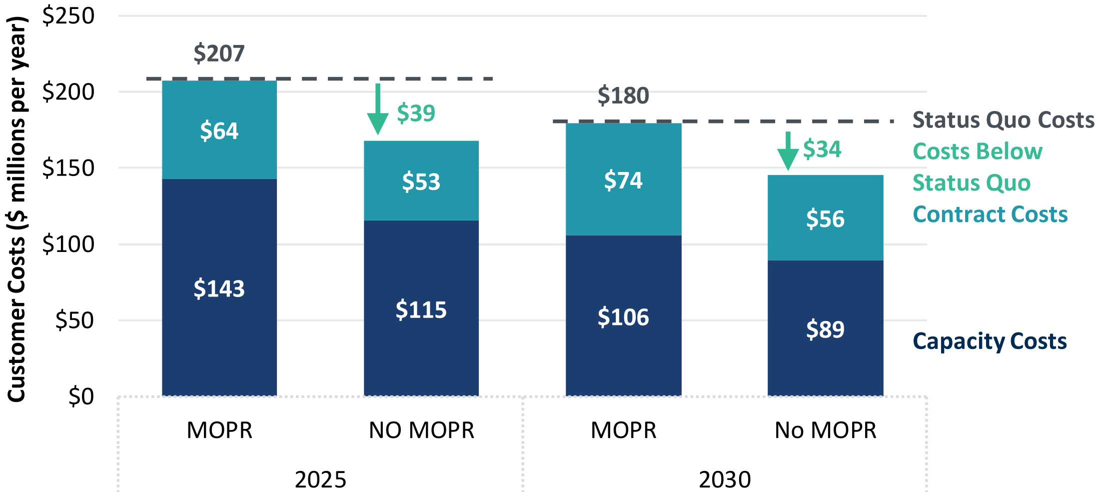


Sources and Notes: Brattle analysis based on RPS specified in D.C. Law 22-257, CleanEnergy DC Omnibus Amendment Act of 2018, compiled by PJM Environmental Information Services, "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," April 30, 2021. Solar and Wind capacity is inclusive of the approximate 154 GWh of PEPCO contracts currently in RFP phase, as proposed by PEPCO in Formal Case No. 1017. UCAP Capacities are calculated based on assumed capacity values from PJM Interconnection, "Preliminary ELCC Results," April 30, 2021.

The increasing UCAP MW of capacity subject to MOPR manifests itself in approximately $30 million of customer costs annually. Specifically, our analysis indicates that MOPR will cost customers approximately $39 million in costs in 2025 and $34 million in $2030. Costs associated with bilateral contracts increase with MOPR because renewable generators are less likely to clear with the price floor in effect. Because fewer renewable generators clear, those generators forego capacity revenues and therefore contract costs rise. Capacity costs increase for renewable generators with the MOPR because fewer resources clear when MOPR is in effect, raising capacity costs.

[27] See PJM Interconnection "Revisions to Application of Minimum Offer Price Rule" filed before the Federal Energy Regulatory Commission July 30, 2021 in Docket No. ER 21-2582-000. PJM's proposed repeal has taken effect as of September 29, 2021, though there is a continued possibility of appeal, see Federal Energy Regulatory Commission, Notice of Filing Taking Effect by Operation of Law, September 29, 2021, Docket No. ER21-2582-000.

FIGURE 7: CUSTOMER COSTS IMPOSED BY MOPR



Sources and Notes: Analysis based on PJM clearing prices previously published from The Brattle Group, "Alternative Resource Adequacy Structures for New Jersey," May 25th 2021, Load forecast data from PJM Interconnection, "PJM Load Forecast Report January 2021," May 25th 2021, and PJM Interconnection, "2022-2023 RPM Base Residual Auction Planning Parameters," May 25th 2021.

C. The Fixed Resource Requirement Alternative

As one approach available for reconciling concerns with MOPR or the resource mix, the District could with draw from participation in the PJM capacity market and utilize the Fixed Resource Requirement (FRR) alternative to meeting capacity needs. Under the FRR alternative, the District would take control over the capacity supply mix serving Washington, DC consumers and utilize its own chosen approach to meeting resource adequacy needs. Procured resources would be submitted to PJM three years before delivery as the state's FRR plan for meeting total and locational capacity requirements. Once FRR is selected, the District would be required to continue using FRR to meet capacity needs for a minimum of five years. The FRR alternative is not a single design option, but instead an open-ended opportunity for the District to determine any and all features of how capacity needs could be met. The open-ended nature of the FRR alternative is an opportunity and a challenge in that the District would need to develop its own, new approach to meeting resource adequacy needs, or else could engage with other leading clean energy states to develop a multi-state FRR approach to meeting capacity needs in alignment with policy requirements.

FRR DESCRIPTION AND PROCEDURES

Since its inception, the PJM capacity market has included provisions for the FRR alternative that can be utilized by any qualified entities that wish to procure capacity outside the PJM capacity market on behalf of their customers. The FRR was originally designed to fit the needs of vertically integrated utilities that conduct resource planning and that do not wish to have uncertainty in the quantity of capacity requirements that can be produced by the sloped demand curve.

Though not originally intended for this purpose, the District can elect to exercise the FRR alternative to limit the impact of the expanded MOPR on District policy resources, and/or to allow the District (rather than capacity market pricing signals) to determine its capacity supply mix. The FRR construct requires that a sufficient capacity resources be procured to meet total and location-specific capacity requirements and remains agnostic as to how the resources are procured or at what price. This mechanism would allow the District avoid some of the costs from the application of MOPR to District policy resources.[28]

Eligible FRR entities interested in participating in the FRR alternative for the first time must notify PJM at least four months before the BRA for the first delivery year the FRR alternative will be in effect. [29] Given the currently compressed PJM auction schedule, the deadlines for FRR election are similarly compressed and accelerated. To initiate FRR beginning with the 2024/25, 2025/26, or 2026/27 delivery year would require formal election of the FRR alternative by February 2022, September 2022 or March 2023 respectively.[30] The election for the FRR alternative requires a commitment of a minimum of five consecutive delivery years. However, FRR elections can be terminated early based on the following conditions:

- PJM establishes a separate Variable Resource Requirement (VRR) curve for a Locational Deliverability Area (LDA) encompassing the FRR service area.
- A state regulatory "structural change," such as the transition to a competitive retail market.

If choosing an FRR alternative, an "FRR entity" must take responsibility for securing capacity commitments on behalf of the designated customers. The FRR entity must submit an FRR plan to PJM three years in advance of delivery (and at least four months in advance of the capacity auction) to identify the specific resources committed to serving customers. If any of the identified resources would fail to fulfill its delivery obligation or incur performance penalties, the associated penalties would be assessed to the FRR entity.[31]

Table 2 summarizes the FRR obligations that would apply for an FRR plan covering the District of Columbia, if one were utilized in the 2022/23 capacity planning year. To serve projected peak customer summer demand of 1,738 MW, the District FRR plan would need to include a total of 1,889 UCAP MW of capacity supply commitments (row [7] in the table). To ensure that the capacity is deliverable to District consumers, 100%, 50%, and 15% of that total FRR obligation would need to be located within the Mid-Atlantic Area Council (MAAC), Southwestern Mid-Atlantic Area Council (SWMAAC), and PEPCO capacity regions respectively (percentages in row [8] and UCAP MW values in row [9]). Note that the nested locational deliverability area (LDA) structure used to represent transmission needs in the PJM market means that the locational requirements are not additive. For example, any capacity within the PEPCO LDA would contribute toward meeting the PEPCO, SWMAAC, MAAC, and total FRR capacity obligations. (See the Appendix for additional discussion of the locational capacity market structure).

[28] The MOPR imposes costs on consumers in two ways: (1) through a double-payment effect in which consumers must "pay twice" for capacity, once through a contract with the clean resource (that may fail to clear the capacity market due to MOPR), and again through capacity market payments that are allocated to cleared resources (including fossil resources); and (2) by causing higher capacity prices than would prevail without a MOPR. By exiting the capacity market under FRR, the District could avoid the double-payment effect, but would not be able to avoid the pricing effect. Higher capacity prices would prevail in the PJM capacity market as long as MOPR is applied to resources across the footprint; resources able to sell into the RPM at a high price would not accept a lower price to sell their capacity into the District FRR, so these higher MOPR-driven prices would continue to affect costs paid by District consumers.

[29] For additional discussion of FRR rules and procedures, *see* Schedule 8.1 in "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," PJM Interconnection.

[30] See PJM Capacity Market Auction Schedule.

[31] If insufficient resources are committed under the FRR plan for a particular day (e.g. because the resource fails to come online), the FRR entity would be subject to a deficiency change equal to 1.2 times the locational capacity market clearing price that would have applied in the auctions. In addition, the FRR entity would need to select whether to utilize a physical or financial non-performance approach to addressing obligations under capacity performance rules, under which the FRR entity would take responsibility for the performance of all individual resources committed under the FRR plan. Sections 11.8 and 11.9 of PJM Manual 18: PJM Capacity Market, May 26, 2021.

TABLE 2: DISTRICT OF COLUBMIA FRR CAPACITY OBLIGATIONS (2022/23 DELIVERY YEAR)

			Total	MAAC	SWMAAC	PEPCO
Total LDA						
Coincident Peak Load	*(MW)*	[1]	150,229	54,839	12,053	5,642
Forecast Pool Requirement	*(%)*	[2]	108.7%	n/a	n/a	n/a
CETL	*(UCAP MW)*	[3]	n/a	4,375	8,310	6,781
Reliability Requirement	*(UCAP MW)*	[4]	163,269	64,514	14,934	7,701
DC Portion of LDA						
Coincident Peak Load	*(MW)*	[5]	1,738	1,738	1,738	1,738
DC Share of Coincident Peak Load	*(%)*	[6]	1.2%	3.2%	14.4%	30.8%
DC FRR Obligations						
Total FRR UCAP Obligation	*(UCAP MW)*	[7]	**1,889**	n/a	n/a	n/a
Minimum Internal Resource Requirement	*(%)*	[8]	n/a	100.0%	50.6%	15.0%
Minimum Internal Resource Requirement	*(UCAP MW)*	[9]	n/a	**1,889**	**956**	**283**

Sources and Notes:
Accounting excludes any adjustments from energy efficiency or price responsive demand.
[1] - [4], [8]: 2022/2023 RPM Base Residual Auction Planning Parameters
[5]: See Monitoring Analytics, *Potential Impacts of the Creation of District of Columbia FRR*, Table 6.
[6] = [5] / [1]
[7] = [5] × [2]
[9] = [8] × [7]

HOW THE FRR ALTERNATIVE COULD BE IMPLEMENTED IN THE DISTRICT

Beyond the above requirements stipulated in the PJM Tariff, the District would need to make a number of choices in determining the most appropriate FRR entity, determining how the capacity needed under the FRR plan would be procured, assigning risks and costs, and ensuring alignment with retail choice and other policies. Though by no means an exhaustive list, we provide here descriptions of three substantially different ways that FRR could be implemented in the district.

- **District FRR Capacity Auctions.** Perhaps the simplest way to implement an FRR would be for the District to conduct auctions to procure the volume of total and location-specific capacity commitments required in the FRR plan. The District would select an independent auction administrator to procure the capacity commitments to meet FRR plan requirements, with procurement costs allocated to customers. Once commitments are secured from resources qualified in the PJM capacity market, these would be submitted by the FRR entity as the FRR plan three years prior to delivery. Variations of the FRR auctions approach could consider:
  - *Selecting different entities to act as the FRR entity*, options including the independent auction administrator, a DC government agency/entity, or the distribution utility PEPCO. Note that even if an independent entity or government agency is responsible for conducting the auctions, the distribution utility could act as the FRR entity responsible for managing FRR plan commitments, contracts with individual resources, and penalty risks.
  - *Utilizing single- or multi-year commitment terms*, but likely maintaining a single one-year-at-a-time commitments approach to minimize customers' risk exposure.
  - *Incorporating policy objectives into the auction*, for example by stipulating that a minimum share of capacity must come from "firm clean capacity" resources.
  - *Alignment with competitive retail market*, to ensure that consumers and competitive retailers retain the opportunity to self-supply their capacity needs.
- **Expanded Planning and Utility Contracting.** Another option would be for the DC PSC to oversee an expanded level of utility contracting, similar to the approach that is currently being pursued to procure long-term contracts

with renewable resources to supply 5% of the District's energy needs. The expanded planning and contracting approach would need to procure 100% of the district's capacity needs. Variations of the approach could consider:

- *Whether contracts would be capacity-only or bundled with REC and/or energy procurements,* with the REC bundling providing an opportunity to incorporate policy objectives into the capacity procurements, but at the expense of requiring greater reliance on utility or PSC judgement (rather than wholesale and retail competition) in making cost-effective resource planning decisions.
- *Contract term,* including whether 1-5 year commitments would be pursued as consistent with the FRR obligation timeframe or whether long-term contracts would be pursued.
- *Whether retail competition and self-supply can be enabled* for any consumers and competitive retailers that wished to engage in their own contracting or supply decisions (and avoid non-bypassable charges associated with utility contracting).

- **Multi-Jurisdictional FRR with Integrated Clean Capacity Market (ICCM).** A broader approach would be to engage in a multi-jurisdictional FRR with other leading clean energy states in the PJM region. As discussed more fully in Section III.B below, the ICCM is a concept adopted by New Jersey as the preferred approach to incorporating the specific policy objectives of each PJM state and DC into the PJM capacity market.[32] One pathway that New Jersey has suggested for implementing ICCM or an alternative regional clean capacity market structure is through a multi-jurisdictional FRR, designed to match the particular policy requirements of each participating jurisdiction. If states organize a forum to develop such a design, DC could participate in that design discussions and set procurement parameters consistent with DC policy goals (subject to the restriction that the procured capacity commitments must be sufficient to fulfill FRR obligations).

ADVANTAGES AND DISADVANTAGES OF ALTERNATIVE FRR STRUCTURES

In the District and across many PJM states, recent consideration of the FRR alternative has been initiated primarily by concerns about the MOPR. In prior assessments conducted on behalf of Maryland and New Jersey, we found that pursuing a well-designed FRR could mitigate approximately 50-80% of the costs imposed by MOPR.[33] However, implementing a poorly-designed FRR introduces the risk of over-paying for capacity relative to staying within the capacity market structure. Exiting the broad regional marketplace introduces greater risks of high capacity prices due to the loss of regional competition to drive lower costs, the risks of implementation flaws, and exposure to the exercise of market power if not sufficiently monitored and mitigated. The need to effectively address market power is also highlighted by a recent Independent Market Monitor (IMM) study examining the implementation of an FRR covering the District.[34] If the MOPR is repealed consistent with PJM's recent filing, mitigating MOPR costs will no longer be a relevant driver for further consideration of FRR.

Regardless of MOPR, the FRR remains a potential pathway for expressing policy objectives alongside resource adequacy needs, if the PJM capacity market is deemed insufficient even after the conclusion of PJM's upcoming stakeholder efforts to address this concern (see Section III). For the purposes of this study, we view the exploration of PJM-wide and multi-jurisdictional FRR as both promising opportunities to enhance alignment between the wholesale market and DC policy objectives. Utilizing a regional approach to supporting policy requirements would

32 See New Jersey Board of Public Utilities, Alternative Resource Adequacy Structures for New Jersey, June 2021, pp. 3-4.

33 See Spees, *et al*. *Alternative Resource Adequacy Structures for Maryland,* Figure 1; and New Jersey Board of Public Utilities, *Alternative Resource Adequacy Structures for New Jersey*, p. 46.

34 This recent IMM Study also estimated Washington, DC consumer costs that could materialize under an FRR at different assumed FRR capacity prices, finding that capacity costs to District consumers could decrease by 6% or increase by 41% depending on assumed FRR pricing. These estimates do not provide a comprehensive assessment of consumer costs however, because they do not account for MOPR-driven costs associated with capacity double-payments and they do not account for pricing interactions between FRR capacity prices and broader market pricing. See Monitoring Analytics, *Potential Impacts of the Creation of District of Columbia FRR*.

maintain regional competition and market efficiencies, mitigate FRR implementation risks, and create opportunities to advance policy objectives. Table 3 provides a summary of the relative advantages of alternative FRR structures for DC in comparison to the status quo option of remaining within the PJM regional capacity market.

TABLE 3: RELATIVE ADVANTAGES OF PJM CAPACITY MARKET AND FRR ALTERNATIVES

	Advantages	Disadvantages
Status Quo Capacity Market (Not FRR)	• Avoid MOPR costs (assuming repeal is confirmed as anticipated) • Cost savings and innovation achieved through regional competition • Upcoming stakeholder forum may create opportunities to better align with DC policy requirements	• MOPR costs (only if not repealed) • Presently, no means express policy objectives within the capacity auction (DC pays a share of the incentives driving new gas plant investments) • DC has limited ability to influence design
District FRR Capacity Auctions	• Avoid MOPR costs (even if PJM's proposed repeal is not confirmed) • Opportunity to advance DC policy objectives	• Medium implementation complexity • Risk of implementation flaws • Exposure to exercise of market power • Loss of regional competitive market benefits
Expanded Utility Contracting	• Avoid MOPR costs (even if PJM's proposed repeal is not confirmed) • Opportunity to advance DC policy objectives	• High implementation complexity • Risk of implementation flaws • Exposure to exercise of market power • Loss of regional competitive market benefits • Likely inconsistent with consumer and competitive retailer self-supply
Multi-State FRR with Integrated Clean Capacity Market	• Avoid MOPR costs (even if PJM's proposed repeal is not confirmed) • Cost savings and innovation achieved through regional competition • Opportunity to advance DC policy objectives • Opportunity to coordinate incentives with several leading clean energy states to achieve more cost effective grid transition	• High implementation complexity • DC cannot unilaterally implement its chosen approach

III. Driving Investments and Operations Toward Cost-Effective Decarbonization

As set out in the Clean Energy DC plan, the District will achieve 100% economy-wide carbon neutrality by 2050.[35] The plan includes 57 actions that together will reduce economy-wide GHG emissions by 55% by 2032 relative to 2006 baseline emissions; reductions will be even more substantial when considering that the District has since doubled its RPS target from 50% to 100% by 2032.[36]

Grid decarbonization plays a critical and central role in the Clean Energy DC plan. The electricity sector is the source of 55% of total District GHG emissions; reducing these emissions through investments in energy efficiency and renewable power together make up the majority of the emissions reductions anticipated between now and 2032.[37]

35 See Clean Energy DC Action Plan, produced for DOEE.

36 See Clean Energy DC Action Plan, produced for DOEE, August 2018, p. xiv.

37 See Clean Energy DC Action Plan, produced for DOEE, August 2018, p. 22, and Table ES 1 (p. xiv)

A 100% clean electricity supply mix is also required to deliver GHG reductions through electrification of transportation and building energy uses.

At the same time, DC's position within the regional electricity grid poses a number of challenges to achieving this decarbonization strategy. The Clean Energy DC plan has identified limitations in its ability to accurately determine the level of carbon emissions embedded within power deliveries to the District, as well as the level of emissions displaced by renewable procurements. The District has noted deficiencies with standard practice of using RECs, at least as currently defined, to demonstrate that GHG abatement is achieved. Neither RGGI nor PJM's wholesale markets currently have a carbon cap or pricing mechanism through which the District could express its requirements to eliminate carbon emissions. Similarly, the wholesale marketplace does not have any mechanism that could be used to procure renewable energy or firm clean capacity.

Each of these limitations, if left unaddressed, can lead to inconsistencies between the incentives introduced by the PJM wholesale markets and the incentives needed to drive clean energy transition on behalf of the District. For example, current PJM market incentives have attracted large-scale investments in over 35,000 MW of new natural gas-fired plants into the PJM region since the 2015/16 delivery year, even while DC and many other states have continued to increase their policy commitments for clean energy transition.[38] These market outcomes stem from the underlying issue that the markets are presently scoped to achieve reliability at least cost, without consideration of GHG emissions or policy requirements.

If the wholesale markets can be reformed so as to fully reflect DC's policy requirements however, they could become a powerful vehicle for driving and demonstrating GHG reductions. A broad regional marketplace is a forum through which DC could join other leading clean energy states to jointly coordinate the development of clean energy resources in consideration of transmission capabilities and the jurisdictions' different (but ultimately aligned) policy mandates to achieve affordable and reliable grid decarbonization. We see several opportunities through which the PJM markets could be enhanced to better support DC's clean energy transition.

Opportunities to Support Clean Energy Transition

- **Marginal and Total Embedded Emissions Data:** Utilize PJM's granular data of grid operations to address information gaps identified in the Clean Energy DC plan, and provide the District with the high-quality data needed to support policymaking, contracting, GHG accounting, and other market design enhancements
- **Regional Clean Energy or Capacity Market:** Introduce a broad PJM-wide marketplace for the procurement of clean energy attributes on behalf of governments, companies, and consumers
- **Carbon Pricing:** Review opportunities to achieve carbon reductions through enhanced carbon pricing, such as by addressing carbon "leakage" from the RGGI market, enabling non-RGGI jurisdictions such as DC to express a carbon price (even if there are no local fossil plants), and/or by introducing a PJM-wide carbon pricing mechanism
- **Enhanced Clean Attribute Products:** Examine the limitations that the Clean Energy DC plan has identified with the traditional REC product definition, using these as the basis to develop the next generation of REC products that improve accountability and incentives relative to GHG objectives

A. Marginal and Total Embedded Emissions Data

CHALLENGES WITH CURRENT PRACTICE

In its Clean Energy DC plan, the District has highlighted several critical information gaps that would be hard (or impossible) to fill without access to the comprehensive grid operations data available to PJM as the market operator.[39] Though the plan has identified a proxy assumption or data source as an interim approach, the DOEE notes

[38] PJM Interconnection, L.L.C., "2022/2023 RPM Base Residual Auction Results," Table 8.

[39] See discussion in Clean Energy DC, pp. 27-29, 137-140.

that more robust solutions will be needed for the District to make the most informed policy choices and accurately measure emissions reductions achieved individual projects, programs, and in total toward the 100% carbon neutral policy mandate.

The primary limitations include:

- **Accurate Accounting of "Scope 2" Emissions**, or the GHG emissions embedded within each MWh of energy delivered to the District. As an initial proxy, the District has relied upon average emissions across a large geographic area, but is currently unable to accurately quantify the level of GHG emissions embedded in deliveries after accounting for transmission limits, time of consumption, and other entities' "title" or contractual commitments with clean energy supply resources
- **Accounting of Emissions Displaced by Renewable Projects,** a similar problem is that DC is unable to accurately measure the volume of GHG displaced by a particular REC or renewable contract, considering its position on the grid and injection profile

Even assuming away restrictions on data availability, the District has outlined a number of tricky conceptual questions that would need to be further reviewed to align with accepted accounting guidance for scope 2 emissions.[40] For example, proper Scope 2 emissions accounting must ensure that no consumer/government is implicitly or explicitly taking credit for the GHG abatement caused by the clean energy resources whose environmental attributes have been contracted to another party. For example, using the average emissions across the PJM system as the basis for scope 2 emissions would under-estimate the District's GHG liability, because the average system emissions rate is reduced by the clean energy programs paid for by consumers in many other states across the PJM footprint.

ONGOING REFORM EFFORTS AND POTENTIAL SOLUTIONS

PJM is the entity that has all of the granular data on grid operations that may be needed to support the District's analytical and data needs. As the system operator, PJM maintains detailed information on power plant dispatch, system losses, consumed energy, and transmission constraints for every five-minute dispatch interval. This rich source of information could be mined to provide robust and accurate accounting of GHG emissions and impacts in support of Washington, DC's accounting needs, contracting decisions, and policy structures.

PJM already publishes some information that policymakers and consumers can use to inform GHG policy.[41] PJM publishes an annual report of system-wide CO_2, SO_2, and NO_X emissions rates, reported in two ways:

- **Embedded emissions**, in tons/MWh, calculated as total emissions across the footprint divided by total demand; and
- **Marginal emissions**, also in tons/MWh, but calculated differently as the *additional* emissions that would be produced if customers were to use *1 additional MWh* of electricity (or, alternatively stated, the emissions that would be avoided by producing 1 additional MWh of clean energy or reducing electricity consumption by 1 MWh).

Both marginal and average emissions rates are essential information for a range of policy purposes, but the annual report does not meet the District's needs as outlined in the Clean Energy DC plan for several reasons (lack of locational granularity, lack of time granularity below monthly on/off peak levels, lack of accounting for deliverability,

40 "Scope 1" emissions are direct emissions from transportation, combustion, or other immediate uses; "Scope 2" are indirect emissions produced by use of energy via carriers (primarily electricity); "Scope 3" emissions are indirect emissions associated with air travel, out-of-jurisdiction commuting, and other upstream/downstream economic activities. The District has utilized accounting guidance as set forth in the Local Governments for Sustainability (or ICLEI US) Community Protocol for Accounting and Reporting of Greenhouse Gas Emissions.

41 See PJM, 2016–2020 CO_2, SO_2 and NO_X Emission Rates, April 2021.

lack of attribution for GHG abatement to consumers outside the District). If such limitations were systematically identified and addressed in collaboration with Washington, DC policymakers and alongside other states, cities, and consumers across the footprint, the report could be expanded into a rich source of valuable information for entities committed to pushing decarbonization.

PJM has also recently begun publishing another highly valuable data set: five-minute, marginal emissions rates for every location in the PJM power system.[42] The locational marginal emissions data will be published continuously and so be readily available to the public and District policymakers. These data will prove enormously useful, and in fact have been specifically identified in the Clean Energy DC plan as a critical input for making a number of policy, contracting, and incentives decisions.[43] Publishing these data will be a substantial achievement and break new ground compared to what has been possible in the past. No other independent system operator (ISO) has regularly published such granular locational marginal emissions data, though many academics, companies, and governments have described how this could be done or developed independent data products providing such information.[44]

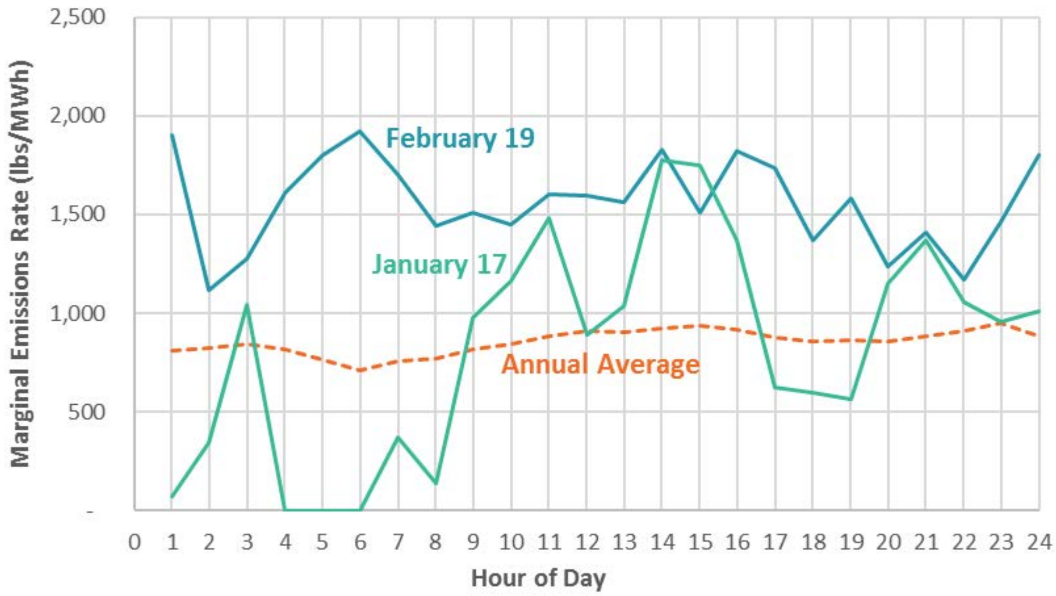
Figure 2 illustrates the value of using marginal emissions rates as a powerful basis for informing policy decisions, using the example of two different days in the ISO New England system and on average across a daily profile. February 19 (in aqua) illustrates a day with high marginal emissions, during which load reductions or incremental clean supply at the right time could displace up to 2,000 lbs/MWh of CO_2 emissions. January 17 illustrates a day with several early morning hours when there were low or zero marginal emissions rates, when injecting additional clean energy into the grid would displace literally 0 lbs/MWh of emissions. When the marginal emissions rate is zero, this means that additional clean energy can only be injected to the grid if room is made by curtailing the output of other non-emitting supply resources. These charts illustrate data with hourly granularity and system-wide scope; the full 5-min locational dataset that PJM plans to produce will illustrate even more variability in emissions abatement potential across time and location.

[42] See PJM Five Minute Marginal Emission Rates.

[43] Specifically the recommended action ESM.7 is to: "Conduct a geospatial analysis of energy consumption, energy demand, PJM's locational marginal price, and GHG intensity based on grid location. Once complete, evaluate the usefulness of the tool and its potential improvements, and work to integrate it in regular, iterative analyses of the District's energy supply system." See Clean Energy DC Action Plan, produced for DC DOEE, August 2018, p. 177.

[44] For example, ReSurety (a private company focused on supporting clean energy contracting) has recently launched a locational marginal emissions (LME) product in Texas with plans to expand their product to cover the US. Other PJM and other RTOs have published aggregated marginal emissions data as in PJM's annual report, but have not reported locational marginal emissions. As referenced in Figure 7, ISO-NE has also published hourly system-wide marginal emissions data from 2015 as a one-time data release.

FIGURE 8: ILLUSTRATION OF ISO-NE MARGINAL EMISSIONS DATA ON TWO DIFFERENT DAYS



Sources and Notes: Derived from five-minute system-wide marginal emissions data from the ISO New England System.

> Newly available locational marginal emissions data will offer the District, for the first time, the information needed to reward and incentivize consumer and supplier activities that the precise time and place where they can displace the greatest GHG emissions.

Historically, policymakers in the District and elsewhere have had to adopt incentive structures and policy choices derived from aggregated data similar to the annual average emissions rates, or approximated estimates of more granular time profiles. Considering only this information, one cannot accurately differentiate between the GHG abatement value of two different resources or policy actions. This lack of differentiation is one reason that the standard REC product and most renewables contracts award the same financial incentives to all renewable generators. If incentives were structured to reward equal GHG abatement potential, e.g. derived from a specific $/ton avoided payment rate, then the policy could direct investments toward the types of actions that displace more carbon for the same amount of funding. For example, local solar, load reductions, shifting consumption profiles in flexible buildings, and efficiency investments within the District are likely to displace more GHG per MWh than renewables in remote locations. An incentive structure derived from a uniform $/ton avoided would focus limited program dollars where they can achieve the most. The policy would place a payment premium on local and properly profiled clean energy supply or load reductions; remote renewables would be incentivized at a lower $/MWh rate, but may still be cost-effective at that lower rate.

The uses of the forthcoming PJM locational marginal emissions dataset are numerous.[45] Examples include:

- As described in the Clean Energy DC plan, forming the basis for a "heatmap" of carbon abatement value of distributed energy resources, efficiency, and building flexibility measures across the District, thus better informing targeted investments;[46]
- Producing an incentives profile against which batteries could be operated to maximize displacement value as discussed more fully in Section III.D below;

---

45 This is a partial list of policy uses. For a more comprehensive discussion of how locational marginal emissions data could be used, see Oates and Spees (2021), *Locational Marginal Emissions: A Force Multiplier for the Carbon Impact of Clean Energy Programs*.

46 See Clean Energy DC Action Plan, produced for DC DOEE, August 2018, ESM 7, p. 177.

- Informing renewable procurement contract decisions to differentiate the most valuable resources on a $/ton avoided basis (rather than on the less precise $/MWh basis), and structure contract payments in proportion to delivered GHG abatement rather than MWh produced; and
- Creating improved rate-making and incentive structures against which building owners can consume energy, electric vehicles can charge (and potentially discharge) from the grid, and distributed energy resources can be operated.

As already outlined in the Clean Energy DC plan, access to accurate and robust data can form the basis for a more affordable, verifiable, and achievable decarbonization pathway. These data can be used by policymakers, consumers, retail providers, and private companies in creative ways that will enable measurable impact and progress on the transition.

OPPORTUNITIES TO ADVANCE POLICY PRIORITIES

PJM's proposal to begin publishing granular locational marginal emissions data is a substantial step toward providing the District the information needed to understand GHG impacts of policy choices. However, this is only one of several key datasets that the District needs and that PJM is in the unique position to provide. Many other consumers and policymakers throughout the PJM footprint are likely in a similar (but not identical) position with respect to their data needs.

To provide the most robust and actionable information to policymakers and consumers throughout the footprint, PJM could begin by engaging with the District and other data users to understand the data needs and uses. Once these needs are sufficiently understood (including complexities associated with accurately tracking Scope 2 emissions), PJM staff could propose how to address these complexities and refine the proposed calculations in a collaborative process. As a starting point, we anticipate that some or all of the following additional data are needed to provide the most informed basis for District policy:

- **Add Total GHG Emissions in CO_2e Terms** to all reported emissions statistics, given that the District and many others utilize total GHG emissions as the basis for climate policy.
- **System-wide, five-minute embedded emissions,** that could form the basis for estimating scope 2 GHG emissions from electricity consumption, as measured in every five-minute dispatch interval in the grid. These data would be calculated in at least two ways to better inform policymaking:
  - *Embedded emissions across all supply* which calculates total system emissions from all resources injecting power into the PJM system, divided by total consumption in a particular dispatch interval; and
  - *Embedded emissions from all supply that does not receive GHG policy or contract support,* in which emissions are calculated from all supply resources, excluding any that are eligible to produce RECs or other defined environmental attributes.[47] These emissions would be divided by PJM-wide consumer demand (less the portion of demand that can be served by the clean resources).
- **Locational, five-minute embedded emissions,** that could be used as the basis for calculating scope 2 emissions from electricity consumption (again calculated in two ways that include or exclude clean energy production). The specifics of this calculation will be complicated, requiring both technical expertise and policymaker input, but would need to consider at a minimum:
  - *How transmission limits should be accounted for* in determining locational attribution. This approach should consider, for example, that the District can access some generation from remote areas of the grid but that a portion of its supply must be locally sourced due to transmission constraints. At the same time, one cannot

[47] One approach would be to assume that a pre-designated list of "clean" resource types should be excluded from the calculation. Another approach would be to use eligibility status within REC tracking systems. Determining the details of the calculation would be one of the purposes of the discussion.

tie a specific set of generators to any specific customer given the free flow of electrons nature of the grid; and

- *Relevant geographic areas*, for example to calculate embedded emissions at each node in the grid as well as at aggregated levels such as by zip code, county, District/state, or other requested level.

- **Expanded annual reporting of emissions information**, expanding on the current annual emissions report to include additional information such as summary information covering the above data, aggregating interval-specific data into annual GHG emissions statistics requested by the District or other jurisdictions, and other information that may be requested by governments and consumers.

There may be additional data needs beyond those suggested here that are needed by the District and others addressing climate change, but this rich set of data reporting would unlock innumerate opportunities to enhance decision-making toward affordable clean energy transition. They would inform many dozens of policy and academic studies every year. Further, these data, if developed properly, could form the gold standard of GHG reporting that would and could be emulated across the US and globally.

B. Regional Clean Energy or Capacity Market

CHALLENGES WITH CURRENT PRACTICE

As discussed in Section I.B and in Appendix, the price signals created by the PJM marketplace provide incentives that drive private companies' investment decisions. These pricing signals express the need for energy and reliability at different timeframes and in different locations; investors respond to these signals by developing more generation, storage, or demand response that can provide what the system needs. The marketplace uses competitive forces with the goal to serve reliability and energy needs at least cost.

But PJM's market prices do not reflect the District's policy requirements for 100% renewable power supply by 2032 and 100% GHG reductions by 2050. For that reason, the investment and retirement signals created through the PJM markets do not always align with the District's energy vision, nor the least-cost pathway to carbon neutrality. One example is highlighted by the results of the most recent PJM capacity auction in which 4,800 MW of new gas plants entered the market, even while some clean resources exited the market or failed to clear including 2,300 MW of demand response and 5,500 MW of nuclear.[48] District consumers are paying a portion of the capacity payments awarded to these new fossil fuel plants, investments that cannot make sense for a jurisdiction that will fully decarbonize its power supply over the next decade.

The most cost-effective pathway to the District's clean energy future would shift incentives toward the development of new renewables and firm clean resources. Presently, however, the PJM market does not have a way for the District to express its renewables requirements, preference to rely on firm clean capacity, or GHG reduction requirements (this latter point to be discussed in Section III.C). The District can use contracts and other policy mechanisms to meet these requirements, but does not presently have a way to ensure that the markets do not introduce offsetting changes that undermine progress on GHG abatement.[49]

[48] Values reported on a UCAP MW basis. New supply is from p. 2, identified as gas generation from Table 8; demand response is reported as 1-year decrease in cleared resources from Table 3A. Uncleared nuclear as self reported by Exelon (not accounting for all PJM nuclear supply, and derated by an assumed 7% outage rate. See PJM 2022/2023 RPM Base Residual Auction Results and S&P Global, "3 Exelon nuclear plants fail to clear PJM capacity auction", June 3, 2021

[49] Capacity market dynamics illustrate this tendency of markets to partially offset or compensate for policy actions. For example, if DC wishes to ensure that firm clean resource mix is relied upon to meet 50% of its resource adequacy needs, it has the option to develop a portfolio of firm clean supply resources such as storage, solar, demand response, and combustion

Continued on next page

If PJM markets could be reformed so as to fully incorporate the District's policy requirements, then market signals could become a powerful tool through which the District drive affordable GHG reductions (and use the PJM markets to integrate these requirements alongside requirements for reliability and affordability).

ONGOING REFORM EFFORTS AND POTENTIAL SOLUTIONS

Several states, stakeholders, and PJM itself have identified the need to align the RTO markets with state policies by introducing a regional marketplace for clean energy attributes. In ISO New England, the states have conducted a series of workshops and authored a joint report to review alternative approaches that could be used to coordinate clean energy procurements on a regional scale; the ISO and stakeholder body are engaging in a "Pathways" engagement to conduct analysis of alternative approaches.[50] The PJM Board has tasked PJM to engage with stakeholders on a similar effort to examine whether it should develop a regional clean energy marketplace.[51] Most of these discussions are derived from one of the following two design proposals:

- **Forward Clean Energy Market (FCEM)**[52] which would be a marketplace through which governments, cities, consumers, and retailers could procure clean energy attributes in a coordinated regional auction conducted each year, three years prior to delivery; or
- **Integrated Clean Capacity Market (ICCM)**[53] which would integrate the procurement of clean energy attributes alongside the procurement of capacity needs in a single combined auction.

turbines retrofitted for clean fuel. The additional capacity supply would reduce PJM capacity market prices and incentivize retirements. Some of the retirements would be from aging fossil plants but some clean resources would also exit the capacity market such as merchant demand response, merchant storage, and nuclear. Thus, the impact of DC's policy to advance firm clean capacity could be partly offset by the broader market response. On the other hand, if DC were able to express a requirement for firm clean capacity within the PJM capacity market itself, this would correct the tendency toward offsetting response.

50 See New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid, and New England Power Pool Potential Pathways.

51 See Almgren, PJM Chair, April 2021 Letter to Stakeholders and Keech, Capacity Market Reform Committee Presentation, August 2021

52 The FCEM was originally developed as part of the 2017 New England stakeholder efforts, conducted at the states' request, to develop a regional clean energy marketplace, but has since been developed into a detailed design proposal. See Spees et al, *A Dynamic Clean Energy Market in New England*, November 2017 and Brattle Group, "Framework Developed by Brattle Economists on Forward Clean Energy Market Presented to U.S. Congress", September 16, 2019.

53 The Integrated Clean Capacity Market (ICCM) proposal was developed by ourselves and the New Jersey Board of Public Utilities, in consultation with representatives of other states, private companies, and environmental groups. See New Jersey Board of Public Utilities Notice of Work Session and ICCM Report, January 21, 2021.

In its recent Investigation, the New Jersey Board of Public Utilities examined a range of approaches and identified the ICCM as its preferred approach to meeting reliability needs and serving its 100% clean energy goals in a unified, market-based fashion.[54] Finding that:

> Incorporating New Jersey's clean energy goals in the regional market is the most efficient way to provide New Jersey consumers with reliable, affordable, and carbon-free electricity. A clean power grid is necessary to address the crisis of climate change. The transition to a clean energy future must happen, and will happen, with or without a working wholesale power market. But the transition to clean energy can be faster, better, more reliable, and more affordable if power markets are reformed to focus incentives toward achieving policy goals.
>
> — ***New Jersey Board of Public Utilities*** [55]

Though there are several variations of both FCEM and ICCM, the central is simple: an annual, three-year forward auction designed to procure large volumes of clean energy on behalf of many buyers. Participating governments and other large buyers of clean energy would determine their own demand for clean energy attributes, as consistent with state policy targets and budgetary caps.[56] PJM or an independent auction administrator would aggregate the expressed demand bids into an annual auction designed to procure large volumes of clean energy from the broadest possible array of clean energy suppliers across the entire market footprint (subject to each buyer's specified eligibility limitations). Qualified sellers would offer their clean energy attributes for sale in the marketplace, with new renewables eligible for a multi-year pricing commitment. The regional marketplace would, for the first time, create the opportunity to coordinate procurements on a broad regional basis so as to align with bulk grid system reliability needs and transmission constraints. Some variations of a regional FCEM or ICCM marketplace would likely be FERC-jurisdictional market designs, with states maintaining authority to define the quantity to be procured on their behalf. Other variations (such as an ICCM implemented under an FRR structure, or implemented by the states themselves) could remain non-FERC-jurisdictional markets, similar to how the RGGI marketplace is governed.

Each state or jurisdiction would tailor its participation in the regional clean energy market in a way that best serves its policy goals and mandates, with the design developed to provide a substantial degree of flexibility in how to express policy requirements. For example, a state could use the platform to:

- Procure a portion or all of the state's renewable portfolio standard (RPS) mandates,
- Meet technology-specific RPS carve-outs from state-qualified resources,
- Retain existing nuclear resources, including the option to apply budgetary caps from Zero Emission Credit (ZEC) programs while at the same time introducing additional competitive pressure for achieving more cost-effective nuclear payment prices,
- Determine whether to procure state-defined clean energy attribute products (e.g. Class I RECs, solar RECs, ZECs) or whether to transition to procuring new or more advanced regionally-defined clean energy attribute credit (CEAC) products,
- Use a "demand curve" procurement format designed to accelerate clean energy achievement by procuring higher volumes of clean energy attributes if prices are low, and/or
- Offer the clean energy marketplace as a voluntary procurement vehicle for cities, companies, and competitive retailers to meet their own sustainability goals.

---

[54] See Silverman et al, *Alternative Resource Adequacy Structures for New Jersey*, June 2021.

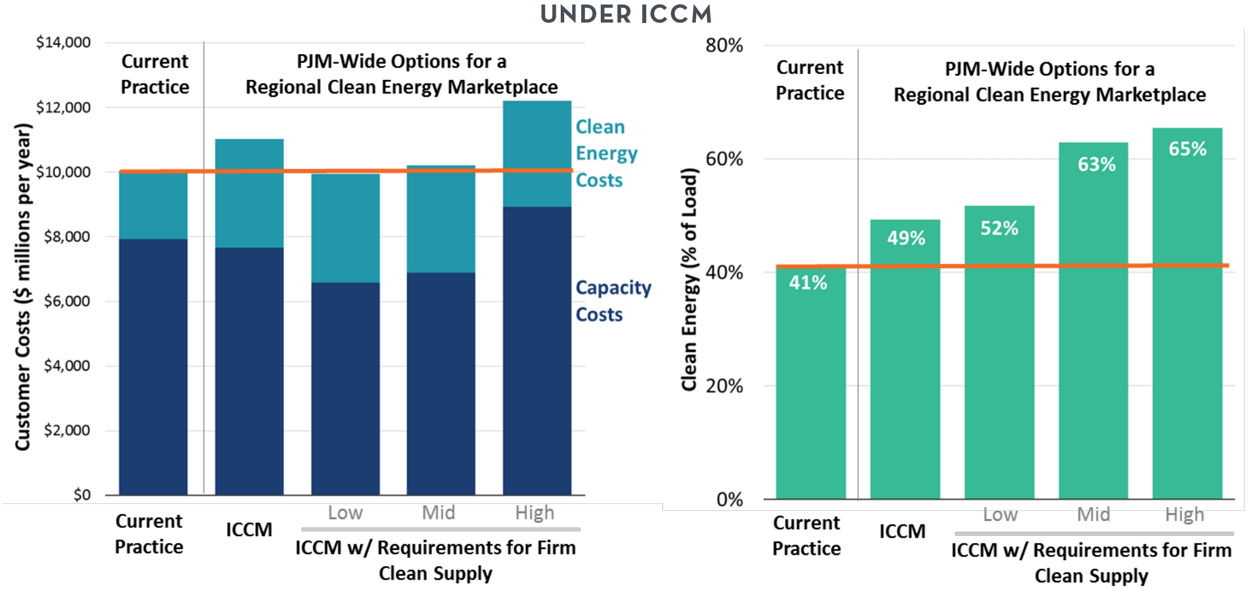
[55] See Silverman et al, *Alternative Resource Adequacy Structures for New Jersey*, June 2021, p. 3.

[56] Each buyer could specify: (1) the attributes they wish to procure, whether state-defined renewable energy credits (RECs), zero emission credits (ZECs), or regionally-defined clean energy attribute credits (CEACs); (2) the targeted volume of attributes they wish to procure; and (3) the maximum price they are willing to pay for each quantity procured.

Both the FCEM and ICCM designs have the ability to accommodate all of these participation options, but likely would need to be refined in coordination amongst all participating jurisdictions to maximize the broader value. In the ICCM variation, the new market would replace and build on PJM's current capacity market; capacity needs would be procured for all customers (including those with or without carbon goals) while clean energy would be procured only for a subset of jurisdictions. In our analysis of ICCM on behalf of the New Jersey Board of Public Utilities, we found that the revised market design could significantly accelerate the clean energy transition as illustrated in Figure 9. Under current practice with each jurisdiction implementing their own separate policies, the PJM region may achieve 41% clean energy by 2030; under ICCM clean energy achievement could increase to 49-65% of load depending on the specifics of the design. The capacity mix in the PJM region can also be driven substantially toward clean energy resources by ICCM, with gas and coal making up approximately 73% of capacity supply under current practice, but reduced to approximately 44% gas (and nearly eliminating coal) under the high clean capacity requirement variation.

These increases in clean energy achievement would be achieved at costs in the range of $0 to $16 per MWh of incremental clean energy. These modest cost increases would be possible because the ICCM redirects wholesale market payments away from fossil resources and toward the clean resource mix needed to meet policy mandates.

FIGURE 9. PJM-WIDE 2030 CUSTOMER COSTS (LEFT) AND CLEAN ENERGY SHARE (RIGHT) UNDER ICCM



Sources and Notes: See Appendix C, Alternative Resource Adequacy Structures for New Jersey.

OPPORTUNITIES TO ADVANCE POLICY PRIORITIES

In the Clean Energy DC plan, the District has identified various shortcomings with traditional policy instruments that have been utilized to achieve renewables requirements, including its finding that 100% RECs does not necessarily mean 100% GHG-free electricity (as discussed further in Section III.B). To address these limitations, the District has been actively engaged in policy efforts to develop or enhance long-term renewable contracts and otherwise enhance its ability to achieve the 100% by 2032 renewables requirement.

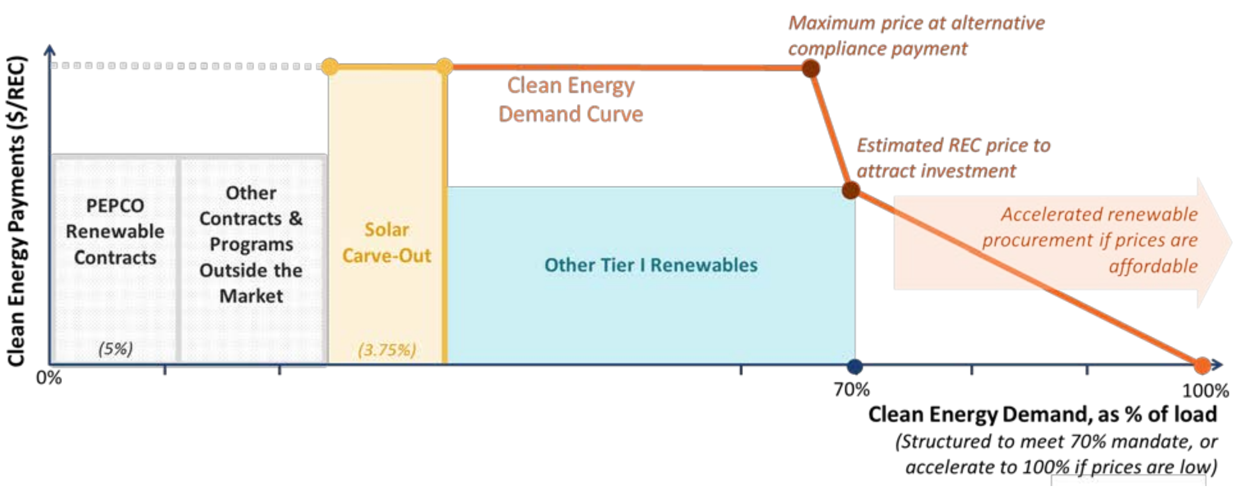
The development and introduction of a regional clean energy and/or capacity markets such as FCEM or ICCM offers a significant opportunity for the District to represent its policy goals in the PJM marketplace. It also offers an opportunity to procure renewable power supply through an alternative auction format that can be tailored to meet policy requirements and has the potential to deliver clean power at affordable prices. The centralized regional auction format also offers the opportunity for the District to coordinate with other leading clean energy states and consumers in a way that would not be possible through unilateral policies or contracts. Depending on how such a regional marketplace is designed, it could be used to: procure clean attribute credits (after applying District-specific eligibility requirements); procure total and locational capacity needs; ensure a specified share of capacity is provided by clean resources; and enforce transmission deliverability constraints on procured resources.

Figure 10 illustrates how the District could translate its RPS into clean energy demand the ICCM for an illustrative year 2028, when the total renewable requirement will be 70%. Demand could be expressed as follows:

- **Total RPS Requirements:** The District would develop (or instruct PJM how to develop) a demand bid for District-qualified renewable resources. Of the total 70% requirement, a portion would already be met through approved utility contracts and a range of District programs (gray boxes) and would not be procured through the regional market platform. The District would likely require the flexibility to adjust the portion of renewable needs to be procured within the regional market, and through other mechanisms.
- **Solar Carve-Out:** The District will have a 3.75% solar carve out requirement in 2028 as illustrated in the yellow box. The District may want to retain the option to fulfill that carve out in part or in full through other policy mechanisms, but may wish to procure a portion of the District-qualified solar from within the regional market. Any such carve-out demand procured in the auction might clear at a price premium relative to other Tier 1 RECs, up to the price cap (which could be set at the solar alternative clearing price or lower).
- **Tier 1 Renewables:** Remaining Tier 1 Renewables (blue box) would be procured to meet any remaining demand, relative to a sloping demand curve (red line). Using a sloping demand curve shape would be voluntary, but may be useful to the District as a means to express willingness to buy more or less renewable supply via the regional market as a function of price. If qualified renewable supply is available at very low prices, the District could accelerate purchases (but if costs are high, the volume of purchases could be reduced). New renewables that clear the auction would earn multi-year commitments.

In addition, though not reflected in the figure, the District could express any requirements that a minimum share of its capacity requirements would be provided by firm clean capacity, and be subject to transmission deliverability constraints applied in the auction.

FIGURE 10: ILUSTRATIVE DC DEMAND PARAMETERS IN A REGIONAL CLEAN ENERGY MARKET (2028)



Sources and Notes: Under ICCM or FCEM, the District would have the option (on a voluntary basis) to procure a portion of its renewable supply via the regional market platform. This figure illustrates one way that District demand could be expressed in the auction, as relevant for the year 2028. In this example a share of total renewable procurements is assumed to be met via PEPCO contracts and other policy programs (and so not procured via this market mechanism). The yellow box illustrates how a share of procurements could be stipulated to be procured from District-qualified solar resources (these resources could clear at a price premium relative to the standard REC). The remainder of District-qualified REC procurements would be from other renewable resources. The sloping orange demand curve would work to procure higher volumes of RECs if prices are low (and buy less from the regional market if prices are high).

C. Carbon Pricing in the Energy Market

CHALLENGES WITH CURRENT PRACTICE

GHG emissions are an unpriced environmental externality that impose costs on society; nearly every economics textbook references such emissions as the classic example of a "market failure" that will not be corrected without policy intervention.[57] The preferred remedy from an academic level is to impose a carbon price on emitters that is high enough to reflect society's willingness to pay to eliminate the emissions. Then emissions would drop to the "correct" level where private entities will pay up to that cost to avoid emissions, and all cost-effective means of achieving GHG reductions will be pursued. Another approach is to identify the maximum acceptable quantity of emissions and impose this as a cap on emissions, and allow private parties to trade emissions allowances as long as total emissions do not exceed the cap. The insight within both of these frameworks is that applying a single, uniform GHG price across an entire economy will inspire private actors to pursue all low-cost opportunities to displace emissions and thus achieve the desired policy outcome at the minimum possible cost to society. The benefits of this single carbon price framework has a substantial volume of evidentiary support from academia, industry, and practice.[58] The broader the geographic and economic footprint a single price can be applied over, the greater the opportunity to achieve more emissions reductions, more economic savings, or both.

Despite the widely-understood benefits of a regional carbon price, there is no uniform carbon price applied globally, nationally, nor within the narrower scope of the PJM wholesale electricity markets. A subset of PJM states do participate in the Regional Greenhouse Gas Initiative (RGGI) electricity sector cap-and-trade market that, once Pennsylvania joins, will represent 55% of the energy consumed across the PJM footprint.[59] But there are important limitations on current format of the RGGI marketplace, most notably:

- **Emissions Leakage:** Emissions leakage from a carbon program occurs when covered emitters reduce production due to higher costs, only to have their production displaced by higher-emitting producers not covered by the carbon cap. In RGGI, the risks of emissions leakage were understood even at the time that the program was originally developed.[60] For example, a gas generator within a RGGI states must pay a price to emit CO_2, thus increasing its production cost and the price offered into the PJM energy market, reducing its production, and reducing its carbon emissions. The leakage problem arises because non-RGGI fossil generators do not have to pay for their carbon emissions, meaning that higher-emitting coal or gas plants may displace the lower-emitting RGGI plant. The size of the leakage problem will increase alongside the carbon price.
- **The Current RGGI Framework Does Not Enable Meaningful Participation for Washington, DC:** The RGGI cap-and-trade framework requires each participating jurisdiction will establish a cap on local power plant emissions within their own borders. These emissions caps are pooled and reduced over time, with participating generators able to trade freely across borders as they reduce their individual emissions and drive toward the multi-jurisdictional GHG reductions goal. The District does not have any GHG-emitting power plants within its borders. In its climate commitments the District has adopted the mandate to eliminate GHG emissions from its power supply, but it is not able to reach outside of its borders and impose a RGGI-style cap on the emissions from power plants across the PJM region that contribute to the District's scope 2 electricity emissions.

The cost-effective GHG abatement potential of a PJM-wide carbon price could be substantial. These emissions reductions can be achieved at very low costs because a modest GHG price can achieve tremendous fuel-switching

57 For example, see N. Gregory Mankiw, Principles of Microeconomics, 5th ed. Mason, (OH: South-Western Cengage Learning, 2009), p. 204.

58 See for example: World Bank/PMI Climate, State and Trends of Carbon Pricing 2021 Executive Summary, with link to full report, 2021.

59 Calculated from information provided by monitoringanalytics.com, Percentage of PJM Load by State.

60 See: The Regional Greenhouse Gas Initiative, CO_2 Emissions from Electricity Generation and Imports in the Regional Greenhouse Gas Initiative: 2018 Monitoring Report, March 11, 2021.

from coal to gas across the PJM footprint, and by providing incremental incentives to attract and retain clean energy resources especially nuclear, renewables, and storage. At present, the District does not have any means to express its willingness to pay to avoid carbon emissions in its PJM-delivered power supply. Further, implementing a regional carbon price in PJM is faces jurisdictional and policy barriers, given that some states within the PJM region do not have any GHG or RPS goals.

ONGOING REFORM EFFORTS AND POTENTIAL SOLUTIONS

PJM, along with many market participants and independent parties, have long understood the economic benefits of a regional carbon price. The FERC has also recently conducted a technical conference on carbon pricing mechanisms within RTO markets, generally finding that carbon pricing can be a tool for reducing carbon emissions within wholesale markets. In general, these prices have been set by states, with RTO rules (as in California) developed so as to align with the state policy goals and support efficiency in bulk system operations.[61]

Over approximately two years from 2019-2021, PJM hosted a stakeholder forum within the Carbon Pricing Senior Task Force, with the aim to develop a design proposal for a carbon pricing mechanism that PJM could implement within its energy market.[62] In one of its analyses of the carbon pricing impacts, PJM examined the effects of adopting a uniform carbon price across the RTO footprint. The analysis found that in comparison to a no-carbon-price case, system-wide carbon emissions per MWh would be reduced by 9%, 16%, 23%, and 29% by applying carbon prices of $7, $15, $25, and $50/short ton of CO_2 respectively.[63] These emissions reductions are achieved primarily through fuel-switching by reducing production from coal to gas plants and reducing the total amount of fossil generation for export from the PJM region. Emissions would be further reduced over the long run by a higher carbon price by providing incrementally greater incentives to retire coal and other high-emitting plants, while providing more incentives to retain existing nuclear and hydro and increased incentives to build carbon-reducing clean energy resources. PJM has further found that carbon pricing that covers only a portion of the PJM footprint (as RGGI does) is less effective at reducing carbon emissions than a system-wide price, but the effectiveness of a sub-regional carbon price could be enhanced through other adjustments to the energy market dispatch.

Stakeholders have developed and proposed a range of pricing proposals aimed at addressing different challenges, including:

- **PJM-Wide Uniform Carbon Pricing**, likely with the price level set equal to RGGI prices. Under this approach, all fossil generators in PJM would be assessed a uniform carbon price (RGGI generators would pay into RGGI as today, while non-RGGI generators would pay carbon charges to PJM). Energy prices would increase modestly due to the application of a carbon charge, but these cost increases would be offset because PJM would return the collected carbon charges to customers. A similar design concept has been more fully fleshed out and analyzed in the New York ISO system.[64]
- **Carbon "border pricing" adjustments to address leakage,** that would apply a carbon-price adder on any imports into a carbon-pricing region from a non-carbon-price region. This border adjustment would impose a barrier against importing power from high-emitting resources into jurisdictions that prefer to rely on clean energy resources. One variation of this option is to impose a limit within PJM market dispatch that prevents supply from fossil generators that do not pay a carbon price from exceeding the demand from customers in non-carbon-

61 See FERC Notice of Policy Statement on "Carbon Pricing in Organized Wholesale Electricity Markets," issued April 15, 2021. Docket No. AD20-14-000.

62 See PJM's Carbon Pricing Senior Task Force.

63 Calculated from detailed modeling results from RTO-wide carbon pricing results, see PJM Interconnection, "Expanded Results of PJM Study of Carbon Pricing & Potential Leakage Mitigation Mechanisms," May 19, 2020.

64 Brattle Group, "Brattle Economists: [New York ISO] Carbon Charge Could Help Meet New York Decarbonization Goals More Cost-Effectively", August 14, 2017.

price states.[65] Another variation would be to use locational marginal emissions data (as discussed in Section III.A above) to apply a carbon border price.[66] These border pricing approaches still allow for the possibility of imports from non-RGGI emitting resources, but at least would prevent the most uneconomic sort of leakage to higher-cost and higher-emitting resources. These solutions are quite technically complicated, but the details of these complexities can have a substantial influence on the efficacy and cost of each alternative.

- **RGGI allowance budget adjustments,** in which PJM would track the emissions embedded within imports to RGGI states and report these results to those jurisdictions. RGGI program budget caps would be reduced by the same amount to ensure that realized emissions reductions remain at the required levels. This budget adjustment concept could also be used alongside carbon border pricing in order to achieve dual aims of preventing uneconomic leakage and maintaining consistency with the carbon budget.

PJM and several market participants have conducted economic analyses comparing a wide range of such design alternatives. Across a number of studies, PJM has noted common threads in these studies findings (all of which align with our expectations as well), including that: (a) RGGI prices can be expected to remain low for the foreseeable future, (b) carbon pricing achieves emissions reductions cost-effectively, with the magnitude of emissions avoided increasing with geographic scope and the carbon price, (c) there are a wide rage of potential approaches to addressing leakage (but with different levels of effectiveness).[67]

OPPORTUNITIES TO ADVANCE POLICY PRIORITIES

To date, the District has not had a feasible opportunity to utilize a carbon price or cap-and-trade program through which it could express the desire to reduce or eliminate carbon emissions embedded within power supplies. The introduction of a PJM carbon pricing mechanism could create that opportunity for the first time, but only if the approach offers a meaningful opportunity for the District to participate as a jurisdiction that is not a RGGI member and does not have any local fossil plant emissions.

Several of the design proposals or components of those proposals considered to date within the PJM carbon price task force could be utilized to support the District's policy objective to reduce and eliminate GHG emissions from energy delivered to the district. The combination of such proposals that may offer the most meaningful support to advance the District's policy objectives would be to:

- **Implement a PJM-wide price on carbon or GHG emissions.** A regional carbon price would reduce emissions from the power supply delivered to District consumers, likely tied to the RGGI price.
- **Allowing carbon price opt-out for jurisdictions that choose not to participate.** It is possible that such opt-out states would represent the minority, given that states participating in RGGI will soon make up 55% of PJM demand; when combined with non-RGGI jurisdictions with RPS standards (including leading jurisdictions such as the District and Illinois), these states represent 92% of all PJM demand.[68]
- **Implement border pricing to prevent leakage to opt-out states.** Of the border pricing options considered to date, the variation that may be most promising could include the following elements, with somewhat different provisions applying to customers and generators in carbon-price and opt-out jurisdictions:

In Carbon Price Jurisdictions

[65] This approach has been used in California to impose a carbon border price with neighboring states that are not part of the Western Climate Initiative, see Section 11.3.3.1-2 of California ISO's Business Practice Manual for the Energy Imbalance Market. If applied in PJM, this approach would need to adopt additional components to have the intended effect of preventing leakage and resource shuffling, see more discussion under "opportunities."

[66] See PJM's presentation on Exelon Alternative Border Adjustment Methodology, May 2021.

[67] Tacka, Carbon Pricing & Leakage Mitigation Study Comparisons, February 25, 2021.

[68] Kentucky, West Virginia, and Tennessee being the PJM states that have not adopted renewable mandates. Percentages calculated for the year 2020 from information provided by Monitoring Analytics, Percentage of PJM Load by State.

- Fossil generators pay for carbon emissions, either by buying RGGI allowances (in RGGI states) or by paying carbon charges to PJM (in non-RGGI jurisdictions)
- All fossil and clean resources earn a higher energy price that includes the "carbon component" of the energy price
- Customers pay the energy price including the carbon component
- Customer costs are offset by carbon charge refunds (RGGI state consumers are already partly refunded via RGGI allowance auction revenues; the District and other non-RGGI jurisdictions would be refunded via carbon charges collected by PJM)

In Opt-Out States

- Fossil generators can be operated by PJM's optimized market dispatch engine to run in two different modes: (1) without paying carbon charges, if they supply energy to opt-out consumers, or (2) with paying carbon charges, if they supply energy to carbon-price customers. Fossil generators assessed a carbon charge are paid the carbon component of the price, other fossil generators are paid a lower price without the carbon component
- Clean energy resources are not eligible to earn the carbon component of the energy price
- Customers pay a lower energy price that does not include the carbon component (and are not awarded any carbon charge refunds)

Provisions to Address Leakage

- PJM dispatch will impose a constraint that the maximum output from both clean resources in opt-out states plus fossil resources that do not pay a carbon charge cannot exceed the total customer demand within opt-out states[69]
- PJM will track emissions produced by generators in non RGGI states and that are delivered to RGGI states (so that RGGI states can reduce these emissions from program budget caps)
- External borders between PJM and other regions would apply a carbon border price based on marginal emissions at the exporting border point (ideally based on 5-minute locational marginal emissions, but based on an approximate estimated value until a formal calculation can be developed by the external market operator)

- **Track fossil imports to carbon price states to enable GHG budget offsetting.** PJM would track emissions produced by generators in opt-out states and non-RGGI states whose power is deemed as dispatched to carbon price consumers. RGGI rules would need to be updated to reduce program budget caps accordingly; the District and other non-RGGI jurisdictions could use the same information in their own GHG accounting (as coordinated with any data provided as discussed in Section III.A above).
- **Provide regular annual reporting of carbon pricing impacts**, to inform all participating and opt-out jurisdictions of the system-wide and jurisdiction-specific customer costs (including accounting for refunds), carbon abatement achievement, and cost per ton avoided to inform future decisions on participation.

[69] Note: most variations of this approach would allow clean resources in opt-out states to serve consumers in carbon price states, but as noted by Exelon and others, allowing those deliveries enables "resource shuffling" such that the dispatch engine would deem all clean energy in opt-out states to be delivering to carbon price states, while all fossil supply would be deemed to deliver to opt-out state consumers. This would create a windfall of carbon revenues to clean resources in non-participating states while introducing a different form of leakage. See PJM's presentation on Exelon Alternative Border Adjustment Methodology, May 2021.

D. Advanced Clean Energy Attribute Products

CHALLENGES WITH CURRENT PRACTICE

As laid out in the Clean Energy DC plan, the RPS is the single largest measure that will contribute to GHG reductions in the District over the next decade. The RPS will be the single largest contributor to GHG reductions, representing approximately 19% of total District baseline emissions by 2032.[70] The scale of these anticipated reductions are a critical component of the District plan for GHG reductions, but are only been assumed to achieve 57% of the total potential reductions that might be achieved under the RPS.

For the most part, the District RPS uses the standard US model for tracking compliance by requiring that sufficient RECs are purchased to match the required percentage of consumed energy on a MWh-for-MWh basis. However, as District increases toward 100% renewable power supply, the District has begun to identify the limitations of this traditional, simplified approach. The District has identified concerns that procuring 100% RECs will not guarantee 100% elimination of GHG emissions from its power supply, in part due to the lack of sufficient data to verify emissions displacement as discussed in Section III.A above.[71]

The limitations of the traditional REC product are in large part associated with the simplified approach that has been used since they were first conceived to treat all resources equally regardless of when and where they produced clean energy, as long as they met eligibility criteria.[72] RECs have been a powerful tool for tracking and verifying non-duplicative production and consumption of clean energy, but at the same time will face increasing limitations over time. The product does not contemplate the participation of storage or demand response, even though these resources will likely become a critical source of peak-time GHG emissions reductions in any system approaching 100% clean energy. Overall, in the many since RECs were developed, the product has not been refined to better align with policy goals and economic principles.

ONGOING REFORM EFFORTS AND POTENTIAL SOLUTIONS

Given the extensive availability of data and advances in technology capabilities to utilize these data, there is no reason that the District or other users of clean energy attributes should need to continue relying on the traditional simplified product. For example, Google and the M-RETS renewable tracking system have recently announced a partnership to develop and begin using a system for 24x7 REC tracking in support of consumers that wish to verify hour-by-hour load and REC supply matching.[73]

Another next-generation REC product is the “Dynamic REC” or “Carbon Abatement REC” that was originally proposed within the New England IMAPP process.[74] The concept of the dynamic REC, as illustrated in Figure 11, is to award environmental attributes to clean energy resources in proportion to the marginal carbon displacement delivered into the grid. The product would be defined in relation to a required “Standardized Abatement Rate” (pink line), which is

[70] Based on the 9.5% reported in the Clean Energy DC plan, Table ES 1; doubled to 19% given that the RPS has since increased from 50% to 100% by 2032. Additional reductions are anticipated from local solar and utility contracts that also contribute to the total RPS requirement. See Clean Energy DC Action Plan, produced for DC DOEE, August 2018.

[71] See a detailed discussion of these identified concerns in Clean Energy DC, pp. 27-29, 137-140.

[72] The DC DOEE has considered a number of analyses to inform its approach to assessing RECs, including Gillenwater, M., “Redefining RECs- Part 1:Untangling attributes and offsets,” *Energy Policy,* 36 (2008); and Gillenwater, M., “What is Additionality? Part 2: A framework for more precise definitions and standardized approaches.” January 2012.

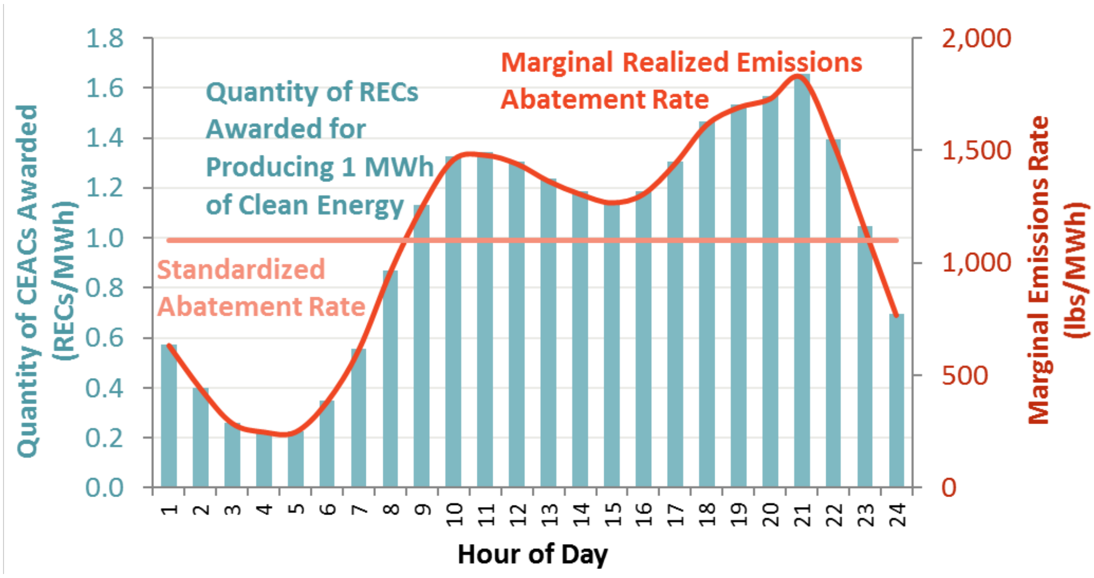
[73] See M-RETS’ Hourly Data.

[74] The dynamic REC product concept is more fully described in Brattle Group, “Framework Developed by Brattle Economists on Forward Clean Energy Market Presented to U.S. Congress”, September 16, 2019, Appendix H.1.

set at approximately 1,050 lbs/MWh in this figure.[75] For a resource producing a flat 1 MW of output across the day, the quantity of dynamic RECs awarded would scale up and down in proportion to the delivered GHG abatement value. Because more REC would be created during high-emissions hours, higher payments (i.e. quantity of CEACs times the price earned from each CEAC) would be earned by resources injecting power during those intervals.

FIGURE 11. ILLUSTRATIVE QUANTITIES OF "DYNAMIC" RECS AWARDED IN A REPRESENTATIVE DAY

FOR A RESOURCE PRODUCING 1 MW OF POWER IN A FLAT OUTPUT PROFILE



This dynamic REC product design introduces several efficiency advantages relative to the simplest 1 REC per physical MWh design that traditionally underpins RPS tracking systems. First, the incentives and payments to clean resources are proportional to the marginal carbon emissions across both time and location, so this approach rewards resources with greater carbon abatement value and focuses incentives for both investment and operations toward those resources that will achieve more GHG reductions faster. Second, a dynamic REC removes the incentives for some renewables over-saturate wind rich locations, as can occur with the flat incentives structure of traditional REC, feed-in-tariff (FIT), and production tax credit (PTC) incentives. Finally, the dynamic REC would for the first time fully enable storage resources to compete head-to-head with renewables as the most effective technology to displace carbon emissions.

Although storage resources do not generate clean energy, the District and many other jurisdictions recognize that batteries will be a critical component of the clean energy transition. Dynamic RECs can recognize that GHG reduction value. Most storage resources will not charge exclusively using carbon-free energy. Thus, every MWh of electricity released from a storage resource has some "induced" carbon emissions that reflects the incremental carbon emissions from the resources on the margin when the storage was charging; the storage resource then displaces emissions when discharging in a higher emissions hour. Thus, storage resources can reduce carbon emissions by allowing low-carbon energy generated in one hour to displace high-carbon energy generated in another.

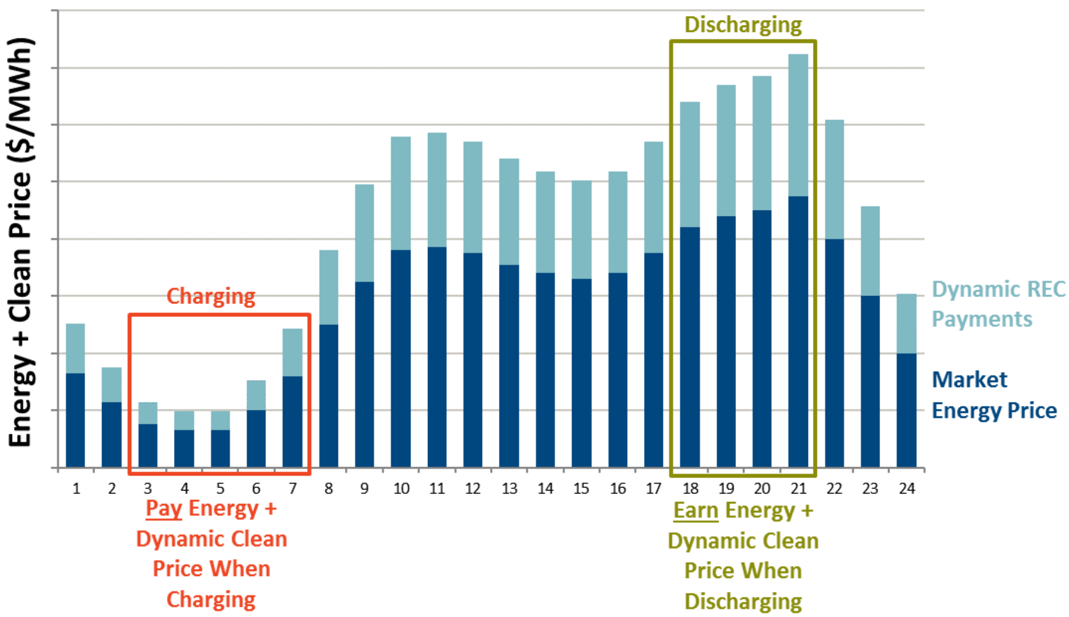
Further, qualifying storage resources to produce dynamic RECs will create incentives for storage owners to operate their assets in a way that maximizes carbon abatement value, as illustrated in Figure 12. In the existing electricity markets, storage resources pay the energy price to charge in low price hours, and earn the energy price to discharge in higher-price hours (dark blue bars). In the PJM market, this operational profile does not guarantee that a storage

[75] The standardized abatement rate could be set based on the average emissions caused by consumers in the relevant jurisdiction, based on the average delivered displacement of all qualified clean energy resources, or based on other considerations.

resource would reduce carbon emissions; in fact it is likely that without a GHG-based incentive to adjust operations, a battery could charge on coal and discharge to displace gas (in addition to incurring round-trip efficiency losses).

The dynamic REC changes the battery's operational incentives so as to incentivize them to "chase" carbon abatement alongside other market revenues. The storage resource would pay the cost of buying RECs when charging to cover the incremental carbon emissions that the storage asset has imposed on the grid (aqua bars). If the storage asset charges during a high-carbon hour, the cost of CEACs will be quite high; conversely, if charging during an hour with only solar and wind generation, the storage asset will pay nothing for carbon emissions. When discharging, a storage asset is paid the energy price to inject power into the grid plus it will earn revenues from selling any dynamic RECs it creates. Discharging in hours with very high emissions means that storage will be paid more. A storage asset can maximize its REC-derived value by absorbing wind or solar power that would otherwise be curtailed, and reinjecting power at times when displacing coal generation. When deciding on the output profile, the storage resource will consider the best way to maximize its value to the grid considering: (a) energy value, (b) ancillary service/flexibility value, and (c) carbon abatement value. That way, storage can continue to play a major role in providing both essential grid and flexibility services as well as assisting to decarbonize at the same time.

FIGURE 12. ILLUSTRATION OF STORAGE PARTICIPATION WITH DYNAMIC RECS



OPPORTUNITIES TO ADVANCE POLICY PRIORITIES

Given that PJM will soon begin publishing locational marginal emissions data, defining a dynamic REC product of the sort described above should be possible to implement in collaboration with PJM Environmental Information System, the entity that tracks REC production and transfers for the District and states throughout the PJM footprint.[76] This system is already developed so as to register qualified resources under each REC program, track the resource's MWh of production at specific point in the grid, and create RECs that can then be traded. The additional step of awarding RECs in proportion to locational marginal emissions would be a novel enhancement to the process that could open substantial opportunities for addressing the District's identified concerns with the current REC system.

The dynamic REC or marginal carbon abatement REC concept may not be the only approach to enhancing performance relative to the District's policy needs, but does illustrate the opportunity for PJM and PJM-Energy

[76] PJM-Environmental Information System is a wholly-owned subsidiary of PJM Interconnection; it manages and operates the Generation Attributes Tracking System (GATS) in which REC transfers are tracked.

Information Ssytem to engage in a collaborative discussion with the District or other jurisdictions to clarify policy goals and use these refined goals to offer the next generation of REC products in support of those goals.

IV. Enabling Emerging Technologies' Contribution to Grid Transition

The Clean Energy DC plan includes a major role for innovative new technologies that will be needed to achieve the 100% renewable electricity supply mix, source a portion of this supply from local sources, and substantially modernize the energy system so as to maintain reliability throughout transition.

The vision for the District's electricity future includes a proliferation of distributed resources throughout the city, focused on providing renewable power, reliability services, efficiency savings, advanced building energy management, and carbon abatement. New technologies and new business models will need to be enabled so that innovative consumers and businesses can identify opportunities to support reliable, affordable, grid transition. Whether delivered via the bulk power system or locally sourced, District consumers' electricity needs will be provided from a wide range of emerging technologies including wind, solar, efficiency, batteries, electric vehicles, and other distributed resources.

As laid out in the Clean Energy DC plan, distributed resources will need to play a major role in providing local supply, local reliability and grid services, and a more resilient energy system through clean energy transition. These resources can offer benefits to control and reduce consumption, help to prevent customer outages, and support system security.

Fulfilling this vision requires rapid institutional and market design change that keeps pace with the rate of technological advancement and with the District 100% by 2032 renewables mandate. Harnessing the full potential of these technologies will not be possible through incremental enhancements to existing frameworks; it will require more foundational changes that may more fundamentally reorganize portions of the power sector. Wholesale markets can play a critical role in unlocking the economic and environmental value contributions of emerging technologies, including both bulk system resources and distributed resources that interact indirectly with wholesale markets. Reforms to retail markets and local policy designs will further play an essential role in enabling new technologies and new business models to flourish throughout the grid edge. These distinct and heavily interacting wholesale and retail marketplaces together must provide the forum through which emerging technologies are conceived, tested, incentivized, and operated in the District's future clean grid.

Opportunities to Support Clean Energy Transition

- **Fully Enable All Emerging Technologies:** Utilize needs-based, technology-neutral product definitions for all electricity markets. Ensure that all resource types that notionally could provide a certain type of grid service are enabled to do so, are able to participate in price formation/dispatch, and face the minimum possible barriers to entry. Ensure that control room operators have the opportunity to gain experience relying on each emerging resource type to provide essential grid services (even if they are not yet commercially viable).
- **Retail Structures:** Even if wholesale markets fully enable distributed resources, additional reforms may be needed in retail rates and retail access rules before a comprehensive suite of resource types and business models could be accommodated.

CHALLENGES WITH CURRENT PRACTICE

The bulk power system across PJM has originally relied on large dispatchable power plants delivering power to inflexible customers, with no material ability to store or shift energy. The wholesale power markets, accordingly, have been designed to represent the complex technical characteristics of thermal power plants and to optimize their operations. For example, a typical fossil plant will offer its power into the wholesale market subject to a multitude of technical parameters including heat rates that differ as a function of power output; minimum start-up and run times; maximum ramping rates; start-up costs; and minimum generation limits to name a few. Decades of academic literature, software advances, and market design enhancements have contributed to refining the tools for optimizing the economic efficiency of these resources' unit commitments, operational dispatch, and integration into wholesale price formation. At the time when PJM markets were first implemented, resources such as demand response, batteries, and renewables could safely be treated as an afterthought; they did not exist in sufficient volumes to materially affect market outcomes and so could be assumed away for most purposes.

Given this history, it is not surprising that new technologies face barriers to full participation when the first arrive on the market. A battery's technical characteristics are also complicated to represent and optimize, but have essentially no similarity to those of a bulk power plant. To their credit, PJM and stakeholders have engaged in nearly continuous efforts to enhance the wholesale market design to accommodate new technologies including large demand response resources and renewables; but the rate of emerging technology advances and deployment is presently outpacing the rate of market and institutional reform.

Looking into the future as envisioned in the Clean Energy DC plan, the structures of wholesale and retail markets will have to be organized under assumptions nearly opposite to those that prevailed in the past. The clean energy grid will have many more small and large renewable and emerging resources; the small resources will be controlled by a number of different entities with a variety of relationships to customers and the bulk power system. Consumers will be more flexible in their consumption patterns and will be able to partly shape their demand around renewable power availability. Batteries and electric vehicles will offer additional flexibility in load (and supply) shaping across the grid.

The market systems that support efficient and reliable production and consumption in that future may have many economic principles in common with the market structures of today (such as price formation at the intersection of supply and demand), but will build on an entirely different set of assumptions, technical constraints, and institutional relationships. Power markets encompassing an entirely clean electricity supply mix will have less need to reflect the complex technical parameters of traditional fossil plants, and a greater need to reflect the complex technical parameters of batteries, electric vehicles, and flexible buildings.

The sector's organization at the retail level may be similarly upended. Traditional approaches have presumed minimal consumer responsiveness, no access to real-time building controls, and one-way power delivery; future retail structures will presume the opposite.

As an example of the need to enhance retail structures, consider the opportunities offered by an aggregated fleet of buildings, each with a different mix of distributed energy resource (DER) assets including distributed solar, controllable heating/cooling systems, distributed storage, and electric vehicles. If a substantial share of these resources were enabled and actively controlled at precise levels of consumption, they could collectively deliver to the grid a large proportion of the system flexibility and reliability services needed to manage the clean grid. Traditional retail structures cannot capture the full value of such advanced controls technology. Time of use rates, if applied to such controllable buildings, could incentivize shifting net consumption to times of day that tend usually to be more favorable to the grid (though in any one day that tendency can be in error). A retail structure that enables aggregators to optimize value relative to optimize value relative to wholesale market energy prices and grid values could be much more powerful in terms of incentivizing real-time responses to current system conditions. Many of the DER devices can be monitored and controlled by mobile phone applications provided by the manufacturer (such as with smart thermostats or electric vehicles) as well as by third-party aggregators that can control many types of DERs. Such an aggregator company has the potential to simultaneously monitor and control the precise consumption (or net production) profiles of many buildings across the city, across the PJM region, or even beyond. If such an aggregator also had the opportunity to maximize production/dispatch value to the grid through direct exposure and participation in wholesale markets, they could reduce the consumers electricity bills, shift net consumption toward hours when more demand is needed to absorb excess renewable output, or provide grid flexibility services.[77] Beyond the structure of rates, traditional retail business models do not readily accommodate the entry of device manufacturers or vehicle-controls-focused companies that are not engaged as full retail service providers or remunerated via utility programs.

The path between today's markets and these future wholesale and retail markets may rely on incremental change or more fundamental step changes, but, in either case, the sector must undergo an institutional transformation equal to its physical transformation.

ONGOING REFORM EFFORTS AND POTENTIAL SOLUTIONS

Enabling innovative players and new technologies is at its core an exercise in applying foundational economic concepts in a new context.[78] The role of a well-functioning wholesale and retail marketplace is to provide a platform of well-designed products, incentives, and infrastructure within which consumers and companies can engage in privately beneficial transactions that will collectively produce the clean grid powering the District's economy. In order for such markets to contribute to that outcome however, a number of underlying governmental and institutional supports need to be in place.

Without sufficient institutional and government supports, most economic sectors (and the electricity sector in particular) can suffer from a number of "market failures" in which private incentives drive behaviors that misalign with the overall social interest.[79] The list of market failures usually includes: public goods, common goods, failure of information, externalities, failure of competition, and incomplete markets. The power sector suffers from all of these, hence the need for robust regulations and governmental structures to enhance competition, market efficiency, and enable emerging technologies.

Table 4 summarizes some of the core elements of a well-functioning marketplace and how these can be utilized through wholesale and retail marketplaces to enable emerging technologies. The general theme is that an efficient market should expose all participants to the incremental costs and benefits induced by their behavior, including reliability and environmental values. These incentives can induce behavior changes that benefit the grid. Even more benefits can be offered by advanced information technology that can offer highly-controlled consumption and production patterns from consumers and distributed resources, but only if the innovative players that can provide these services have access to granular real-time system information needed to use their technology effectively, can earn monetary incentives commensurate with the benefits they create, and do not face barriers to entry that preclude their technology or business model from the start.

[77] Of course, the vehicle manufacturer or third party controlling the vehicle would also need to maximize the vehicle owner's experience (rarely leaving the vehicle uncharged when needed, regularly delivering lower costs or net payments, preserving battery life) or they would risk losing the customer. See additional discussion of opportunities to utilize electric vehicles in controlled charging and vehicle-to-grid applications in, for example, in Hledik and Lee, "Electric Vehicle Managed Charging: Considerations for an Emerging Opportunity," presented to the NARUC EV Working Group, April 2020.

[78] We discuss the elements of a well-functioning marketplace briefly here, focusing on several elements that are particularly relevant for enabling new technologies and new business models. A more comprehensive treatment of these topics and references to classic economics texts, see Newell et al, *Developing a Market Vision for [Midcontinent ISO]: Supporting a Reliable and Efficient Electricity System in the Midcontinent*, January 27, 2014, Section II.

[79] Under idealized circumstances, markets can produce *allocative/Pareto efficiency*, or outcomes in which no further improvements in one market participant's welfare can be achieved without making another party worse off. One of the most interesting applications of economics in the context of the electricity sector is to examine the myriad cases in which these idealized economic circumstances do not hold and identifying potential corrective actions to improve allocative efficiency. In any case, even a perfectly "efficient" market cannot be assumed to produce outcomes that are equitable or meet other policy goals that are not explicitly represented within market incentives. See Newell et al, *Developing a Market Vision for [Midcontinent ISO]: Supporting a Reliable and Efficient Electricity System in the Midcontinent*, January 27, 2014, Section II.

TABLE 4. FEATURES OF A WELL-FUNCTIONING WHOLESALE AND RETAIL MARKETPLACE TO ENABLE EMERGING TECHNOLOGIES

Features of a Well-Functioning Marketplace	Implications and Opportunities for Enabling Emerging Technologies
Use governmental authorities to establish market structures that will not otherwise be provided by private interests (e.g. in the case of externalities, public goods, and common goods)[80]	• Translate environmental requirements to requirements that private consumers and producers can contribute to meeting. The RPS is one example already in place in the District, but there are additional opportunities for the wholesale markets to reflect environmental and policy requirements (see Section III) • Create wholesale market products for reliability that matches the needs of the 100% renewable power system, and ensure that distributed resources and other emerging technologies are enabled to provide these services (see Section V.A)
Well-defined, standardized products	• A product must be defined before it can be transparently priced in a competitive market. If a product is not defined or poorly defined, this can prevent market participants from providing that product or impose excess costs to provide the product
Expose private entities to incentives consistent with marginal value	• Both customers and producers have many ways to change their behavior and operational characteristics (now more than ever before, given advances in information technology). Incentivizing the right behavior changes requires exposing them to the marginal costs or marginal benefits of their actions • Wholesale markets already produce marginal incentives at a highly granular timeframe and locational variability, but they do not yet reflect environmental values. Further, retail structures sometimes mute these granular incentives into an average value; and many distributed resources and third-party providers cannot directly access these incentives
Information transparency	• Granular wholesale prices are available on a continuous basis, as are RTO dispatch instructions (at least for resources that are fully enabled in the wholesale market) • Increased consumer-level and device level information access and transparency may be needed to fully enable some distributed resource business models. For example, third-party providers may need enhanced access to real-time meter data (subject to customer consent) in order to more effectively monitor consumption, engage customers, and control devices
Low barriers to entry	• If products and participation rules are technology neutral, including contemplating the characteristics and barriers of all business models and technologies, wholesale markets can offer a platform through which to monetize grid value (but achieving that outcome requires systematically identifying and removing barriers to entry) • Retail structures similarly can face barriers to entry for new products and business models. Particularly for third-party providers of distributed resources, the structure of standard offer service and retail competition may restrict access for some business models such as: the provision of EV controls by a party that is not the retail provider or utility; or the ability for multiple distributed resource aggregators to serve the same customer (e.g. one that controls a fleet of thermostats and another that controls a fleet of EVs)

[80] A "*negative externality*" occurs when a private transaction between a buyer and a seller causes harm to a third party not involved in the transaction. Pollution is the classic example. Fossil plants will continue to produce emissions that harm the environment and public health because customers want the energy they produce. Neither the customer nor the fossil plant must pay the full costs to remedy the health and environmental harms created, and so excess pollution will be created. A "*public good*" is one that is "non-rival" (meaning one person using more of it does not impede the ability of others to use the same good) and "non-excludable" (meaning that producers cannot limit access only to paying customers). National defense, lighthouses, and radio broadcast are examples of public goods. The market failure in this case occurs because customers get more value out of the good than the cost to produce it, but private entities will not be incentivized to provide as much of the good as the public desires because they cannot monetize the value. "*Common goods*" are "rival" (meaning that one cannot use the good without using it up and limiting others' use of it) and "non-excludable"; the grazing commons is the classic example. See Newell et al, *Developing a Market Vision for [Midcontinent ISO]: Supporting a Reliable and Efficient Electricity System in the Midcontinent*, January 27, 2014, Table 1 (p. 10)

Features of a Well-Functioning Marketplace	Implications and Opportunities for Enabling Emerging Technologies
Low transactions costs facilitated by liquid, centralized exchange[81]	• Most power market transactions involve relatively low transactions costs, given the supporting information technology infrastructure can be used on a largely automated basis to schedule resources and distribute payments • At the retail and distributed resources level however, the same level of liquidity and low-transaction-cost exchange has not yet developed. Some distributed resources can provide their full value directly into the wholesale market, but others may benefit from opportunities to sell into liquid District-focused markets to serve environmental, distribution system, or retail consumer needs
Platform/infrastructure for trade organized by an independent entity	• To the extent that a liquid platform for trade is developed for distributed resources, third-party providers will enjoy the greatest access to that market if the platform is operated and controlled by an independent entity that cannot buy or sell from the market, has no affiliates participating in the market, and that is prevented from privately extracting the benefits from trade[82] • The wholesale markets are operated in this way under the "open access" to transmission infrastructure (by independent system operators not affiliated with transmission companies but many other trade platforms are operated by
Workable competition (i.e. no company can corner or control the market)	• Emerging technologies and new entrants can only succeed by out-competing incumbents through lower prices or providing more value. However, if incumbent players are able to corner or control the market and prevent access from competitors, they can charge high prices for low value

In the wholesale markets, the exercise of enabling emerging technologies is in some ways well under way given the nearly-continuous effort within the PJM markets and as ordered by the FERC to improve the resource-neutral market participation model, including focused efforts to enable demand response, storage, and distributed resources. PJM and stakeholders are currently undertaking a substantial effort within the DER & Inverter-Based Resources Subcommittee to more fully enable and integrate distributed resources in the wholesale market, as is required under FERC's Order 2222.[83]

In its order, the FERC found "that existing RTO/ISO market rules are unjust and unreasonable in light of barriers that they present to the participation of distributed energy resource aggregations in the RTO/ISO markets, which reduce competition and fail to ensure just and reasonable rates."[84] Though some level of distributed resource participation has already been enabled by PJM and other RTOs, the markets will need to be further enhanced to explicitly enable DER aggregators with resource base greater than 100 kW; account for different technology characteristics, enable different bidding formats; improve coordination with retail authorities and distribution utilities; and generally remove barriers to entry.

Under its current straw proposal, PJM envisions explicitly enabling demand response, distributed generation, energy storage, electric vehicles, and energy efficiency (including through aggregators and/or distribution utilities). These

81 "*Transactions costs*" are the costs (whether in the form of materials, time, transaction fees, shipping costs, or complexity) required to make a trade. If transactions costs are too high, they can prevent mutually beneficial trade from occurring.

82 Note that under the US requirements for "open access" to transmission, wholesale markets are run by independent system operators such as PJM rather than by the transmission owners that own the lines over which power is scheduled. Without an independent entity managing access to the market, the owner of the physical or financial platform through which trades are executed is in a position to extract all benefits from trade (i.e. negotiate sellers down to their minimum price, negotiate buyers up to their maximum price, and profit on the difference). This feature of physical network and platform-based markets makes them prone to exercise of market power.

83 See DOE/FERC Order 2222: "Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators", September 17, 2020.

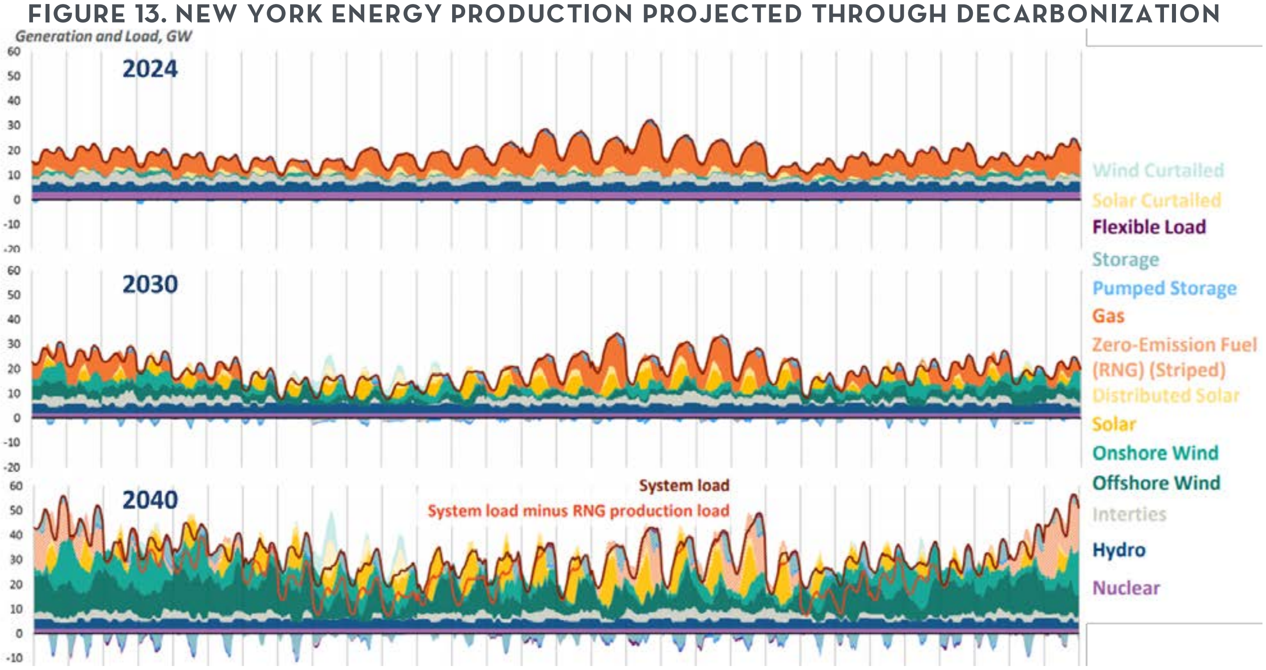
See also: PJM DER & Inverter-Based Resources Subcommittee.

84 See DOE/FERC Order 2222: "Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators", September 17, 2020, p 4.

distributed and aggregated resources will be able to sell into the energy, capacity, and ancillary service markets. PJM is continuing to refine its proposed market reforms and plans to file its proposed suite of reforms with the FERC by February 2022.[85] Even after Order 2222 compliance filings, we anticipate that nearly continuous effort will be required throughout the clean energy transition to enhance the wholesale market, retail market, and enabling infrastructure.

A next phase of emerging resource integration may require a specific examination of how the system will operate in a future as it becomes increasingly dominated by clean energy resources, to ensure that the wholesale market is being proactively (rather than reactively) revised to operate effectively in that future. An example of one such study is the New York Grid Evolution Study, that reviewed how the wholesale markets could operate under the state's carbon goals requiring 70% renewable power by 2030 (approximately 90% total clean when considering nuclear), and 100% clean energy by 2040.[86] Figure 9 summarizes the results of a model illustrating how the New York markets are anticipated to operate as the system reduces reliance on gas power plants (orange) and increases reliance on renewables, batteries, and flexible customers. Some of the primary findings of the study were that system variability could be managed through better use of existing resources and better integration of batteries; however at 90-100% clean energy levels a new technology would be needed to cost-effectively address long-duration/seasonal storage needs (for example through renewable natural gas). The study also identified substantial benefits to be realized through better integration of high volumes of demand response, electric vehicles, and controllable buildings. The results help to identify the types of resources that must be more fully enabled and integrated, and that the system operator must develop comfort relying on to provide essential reliability services.

FIGURE 13. NEW YORK ENERGY PRODUCTION PROJECTED THROUGH DECARBONIZATION



Source: See Lueken et al, "New York's Evolution to a Zero Emission Power System", June 22, 2020, p. 82

[85] See PJM Proposal/Presentation, "Order 2222 Design Discussion", August 2021.

[86] See Lueken et al, "New York's Evolution to a Zero Emission Power System", June 22, 2020,P. 82.

A recent study from the United Kingdom on the Operability of Highly Renewable Electricity Systems has taken a different approach to a similar question.[87] This study examined the emerging reliability needs that will materialize as the island proceeds with decarbonization objectives, and conducted a feasibility study to determine whether and how the system can maintain reliability if it achieves 65% renewable power supply by 2030. Though the majority of system reliability needs have historically been provided by dispatchable power plants, there will be many periods when few or none of these resources would be online and providing reliability services as the system approaches 65% renewable. Thus, the market and/or policymakers will need to identify alternative clean energy technologies that can provide these services. Figure 14 from that study summarizes its findings with respect to a range of clean technologies that would be able to provide needed reliability services (including some services that have not previously needed to be explicitly defined and procured). The study concluded that the United Kingdom will be able to maintain reliability without inducing excess costs, but that this outcome will require advances to improve the ability to rely on both existing and emerging clean technologies.

> A United Kingdom study of operability in high renewable systems concluded it will be feasible to maintain reliability without inducing excess costs, but this will require advances to improve the ability to rely on both existing and emerging clean technologies.

FIGURE 14. UNITED KINGDOM ASSESSMENT OF CLEAN TECHNOLOGIES THAT CAN PROVIDE RELIABILITY SERVICES TRADITIONALLY PROVIDED BY FOSSIL POWER PLANTS

Technology/System needs	Inertia	Short circuit level	Voltage control and reactive power	System restoration
Existing technologies				
Synchronous condensers	✓ (green)	✓ (green)	✓ (green)	✓ (yellow)
Flywheels	✓ (green)	✓ (yellow)	✓ (green)	✗ (red)
Static Compensators	✗ (red)	✓ (yellow)	✓ (green)	✗ (red)
Pumped hydro	✓ (green)	✓ (green)	✓ (green)	✓ (green)
Emerging technologies				
Virtual synchronous machines	✓ (yellow)	✓ (yellow)	✓ (yellow)	✓ (yellow)
Power electronics with energy storage	✓ (yellow)	✓ (yellow)	✓ (yellow)	✓ (yellow)
Hydrogen powered gas turbines	✓ (green)	✓ (green)	✓ (green)	✓ (green)
Bioenergy with carbon capture and storage	✓ (green)	✓ (green)	✓ (green)	✓ (green)
Gas plants with carbon capture and storage	✓ (green)	✓ (green)	✓ (green)	✓ (green)
Innovations in power electronics	✗ (red)	✓ (yellow)	✓ (yellow)	✓ (yellow)

Sources and notes: Green = mature technology demonstrated to provide the service; Yellow = technology that can provide some of the service or new technology in the early stages of deployment; Red = technology that is unlikely to provide the service. See National Infrastructure Commission of the United Kingdom "Operability of Highly Renewable Electricity Systems", February 2021, Table 2 (p.22).

In Australia, the government and system operator have been engaged for several years in an extensive series of reform efforts to enable emerging technologies and manage emerging reliability needs as clean energy transition proceeds. One recent study examined a range of approaches to building out the wholesale market platform to more fully integrate distributed resources, considering four models including: (1) expansion of the wholesale market

[87] See National Infrastructure Commission of the United Kingdom, "Operability of Highly Renewable Electricity Systems", February 2021.

operator to operate and dispatch many more distributed resources; (2) relying on local utilities to act as distribution system operators (DSOs) that would interface between wholesale markets and DERs; (3) identifying an independent DSO (not the wholesale market operator or the utility) to operate; and (4) a hybrid model in which the DSOs adjust individual DER resources' offers into the wholesale market so as to reflect distribution system needs.[88] Another interesting effort in Australia involves DER demonstration pilot programs, through which parties can propose new technologies or business models that should be tested in small-scale demonstrations.[89] The concept of these demonstrations is similar to other pilot programs in that new ideas can be tried and tested out, but with a multi-organizational commitment that the programs will be used by system operator, distribution utilities, and regulatory bodies to identify market design, operational, and communications/controls changes that should be adopted to enable the effective development and deployment of DERs.

OPPORTUNITIES TO ADVANCE POLICY PRIORITIES

Fulfilling the Clean Energy DC plan and 100% by 2032 renewables mandate will require substantial changes within the wholesale markets and retail structures, and likely a greater level of coordination across organizational boundaries so that these structures can work effectively together. Opportunities to advance policy priorities include to:

- Ensure wholesale markets and operations enable the technology mix that will be needed to reliably deliver a 100% renewable supply to the district by 2032 as required by the Clean Energy DC Omnibus Amendment Act of 2018. There are a number of ongoing or planned reforms within the wholesale power markets that will better integrate renewables and other clean energy resources to the wholesale power markets, but many more reforms will be needed before the wholesale market can be described as "fit for purpose" to reliably manage 100% renewable supply to the District (as well as lower, but still large, quantities of clean energy to neighboring states). Enhancements that can be used to enable and reliably integrate these clean energy resources into the wholesale markets include:
  - Beginning with a framework that assumes that the wholesale market must be robust to maintain reliability and fulfill policy goals on a 10-20 year forward timeframe, which at the present time means that large portions of the PJM footprint will need to meet the majority or all reliability and energy needs *only* through reliance on clean energy resources. This proactive approach will require an accelerated pace of market reforms to more fully integrate all types of clean energy resources including grid scale and distributed clean generation, batteries, vehicles, and demand response;
  - Periodically conduct 10-20 year forward looking studies to identify emerging system needs (see also Section V.A below) and identify the types of existing and emerging clean resources that can provide those needs;
  - For all categories of grid scale and distributed resources, engage in a systematic review of wholesale markets to ensure that participation is fully enabled for all technologies that are theoretically capable of providing that service. Identify and address technical inconsistencies, excess transactions costs, or other barriers to entry;
  - Continuing ongoing efforts to finalize and implement reforms to enable a broader suite of distributed and aggregated resources into the wholesale markets to meet Order 2222 requirements, and to continue refining the approach over time to enable more technologies and business models;

[88] See Baringa, Assessment of Open Energy Networks Frameworks, May 2020. Similar studies of alternative market models for enabling distributed resources have been conducted in several other jurisdictions as well, such as the study of Ontario's Electricity System in a High-DER Future: Potential Implications for Reliability, Affordability, Competition and Consumer Choice. Note that PJM's current proposal in response to Order 2222 could be further refined and developed by the District to resemble several of the alternative sector models envisioned in the Australia and Ontario studies; the PJM proposal will govern the operations of the wholesale market and enables the aggregation of DERs, but provides flexibility as to whether utilities or third-party aggregators are directing the individual dispatch of aggregated DERs.

[89] See Australia Electricity Market Operator, DER Demonstrations.

- For emerging technologies or emerging business models, engage with innovative market participants in pilot tests to identify enabling reforms. For example, reforms may be needed to build control room operator comfort relying on emerging technologies, refine telemetry and technology requirements (without imposing excess costs), and ensure that an avenue exists for the technology to monetize their value (including identifying any inconsistencies between wholesale and retail structures); and
- Aim for a wholesale market that has the capability to achieve greater visibility and dispatch/control capabilities over as many distributed resources as possible (either directly or through aggregators), while at the same time acknowledging that many distributed resources may never be fully visible and controllable by the wholesale markets. Less visible or less dispatchable DERs may not be eligible to provide some ancillary services, but can still be incentivized to react to real-time energy prices and respond to capacity emergencies.

- Continue efforts outlined in the Clean Energy DC plan to modernize the district's energy system, including through retail structures that fully enable emerging technologies and new business models. Though retail structures are not the primary subject of this report, they will play a critical role in influencing whether and how consumers and distributed resources can provide benefits both toward the District's policy goals and bulk system reliability needs. Some elements of retail structures that could enhance the effectiveness and alignment with wholesale market signals include:
  - Reviewing retail rate structures, interconnection processes, utility processes, and utility dispatch procedures in consideration of PJM's Order 2222 compliance filing to ensure that distributed resources and aggregators within the District are fully enabled to participate in the PJM wholesale markets. For example, PJM's current proposal would not allow participation from resources that do not have an interconnection agreement with the local utility or that have certain net energy metering rate structures;
  - Reviewing whether there are policy values (such as marginal carbon abatement or associated advanced REC products) or other local reliability values (such as supporting distribution grid operations) that are not yet reflected in retail rates, but that could be defined at the local level and translated into standardized, transparent products or rate incentives that DERs should consider in their operations (alongside wholesale market incentives);
  - Ensure that many types of alternative and third-party business models can be developed and monetize value contributions, including models such as:
    - DERs and aggregators that monetize their value primarily through wholesale markets (even if they do not have any relationship with a particular retail provider or the utility);
    - Enabling alternative pathways to engage with customers other than via traditional utility bills, such as through mobile apps that can be used by the consumer (as well as the aggregator) to monitor and control the distributed resources;
    - Consumers that wish to "sign up" with multiple aggregators to manage different devices or DERs (for example, one aggregator that specializes in controlling vehicles and another that specializes in controlling thermostats, even if both devices are under the same retail meter);
    - Allowing aggregators to package adjacent products and services (such as a package that offers 100% REC-backed renewable vehicle charging, plus bonus payments for allowing controlled charging);
    - Enabling DERs to "value stack" across multiple, non-duplicative value streams that could be provided in the distribution system, to the wholesale markets, toward carbon abatement or REC mandates, and/or toward end-use customer benefits.
  - Reviewing whether emerging technologies and business models can be better enabled through enhanced transparency and access to real-time operational data, customer meter data (given customer permissions), automated settlement structures, or other adjustments to retail structures.
  - If considering a more expansive distribution system operator or other distributed resource market structure, ensuring that the structure does not preclude the innovative solutions that can be offered by aggregators and third-party providers that may not need a DSO intermediary.

- Develop an expanded level of engagement amongst policymakers in the district and the wholesale market operator to identify opportunities to enhance alignment. Given the strong interactions between the wholesale and retail structures, additional coordination across traditional organizational and regulatory boundaries may be needed to improve coordination, incentives, and technical alignment that may be needed to enable distributed resources to reach their full potential.

V. Transitioning to a 100% Clean Energy Grid While Maintaining Reliability

The traditional bulk power system was designed under the assumption that energy would be provided primarily by large thermal power stations that could be centrally dispatched by the RTO. In such a system, energy is available at the incremental fuel and variable costs of running a fossil power plant. Meanwhile, these fossil plants provide most system flexibility and balancing needs nearly "for free" as a by-product of producing energy.

The 100% clean energy grid needed to serve the District's energy vision will look quite different. Energy will often be available at a low, zero, or negative price reflecting the fact that most clean resources have no incremental fuel cost. However, balancing and other reliability services may become scarce for at least three reasons: (1) more balancing services may be needed to manage system uncertainties associated with high levels of intermittent renewables; (2) fossil plants will be less available to provide reliability services as they retire or are maintained in offline status the majority of the time to limit their emissions; and (3) increasing penetrations of DERs will increase system uncertainties as long as they are not visible or controllable by the RTO (though if they can be fully integrated to RTO markets as discussed above, they will be able to contribute to meeting system reliability needs).

To support a reliable transition to the District's 100% renewable grid, the wholesale markets will need to evolve sufficiently to match the needs of a grid that is fully decarbonized (at least across the large subregions of the PJM system that have similarly substantial carbon commitments). These can be supported by proactively enhancing the definition of reliability needs and updating markets to meet those needs, so that the system will remain reliable even when it is no longer possible or cost-effective to rely on fossil plants to provide essential grid services.

Opportunities to Support Clean Energy Transition

- **Ancillary Service Reforms:** Analyze the need for new types or greater quantities of operating reserves or other grid reliability services to maintain operational reliability as the grid becomes more dependent on renewables, batteries, demand response, and distributed resources
- **Energy and Ancillary Price Formation:** Continue reforms aimed at supporting efficient price formation that properly values balancing services and fully integrates emerging resources into price formation (thus limiting or preventing out-of-market reliance on fossil resources)
- **Accuracy of Supply and Demand Accounting for Reliability Needs:** Use effective load carrying capability (ELCC) or similar approaches to accurately measure reliability contribution of all resources including intermittent, energy-limited, and fuel-supply-constrained resources
- **Flexible Capacity Requirements:** If the above reforms would not provide sufficient assurance that resources will be available to meet system flexibility needs, consider adopting flexible capacity requirements
- **Seasonal Capacity Market Design:** Assess winter reliability needs and enhance seasonal capacity market design to fully enable and remunerate seasonal capacity resources

A. Enhancing the Suite of Reliability Products to Reflect Changing System Needs

CHALLENGES WITH CURRENT PRACTICE

The traditional assumption in the electricity sector and in the PJM capacity market has been that thermal power stations would be the dominant resource type; renewables, batteries, demand response, and other emerging supply types were less of a focus given their low penetration rates. But in the transition to 100% clean energy in the District and other portions of the PJM grid, these emerging technologies will make up the majority of the required supply mix. On the demand side, it was also sufficient to use the imprecise measure of reserve margin above peak load to capture all aspects of system reliability; as long as reserve margin was high enough, one could confidently assume that sufficient supply would be available to meet all system flexibility needs and reliability services.

The PJM system (alongside decarbonizing systems globally) will need to revise the approaches to identifying the nature of reliability service needs, determining the quantity that should be procured, and ensuring that clean and emerging resources are enabled to provide these services.

ONGOING REFORM EFFORTS AND POTENTIAL SOLUTIONS

PJM has already identified the need to revise its assessments of reliability service needs as a priority as the grid moves toward clean energy transition. As PJM has recently articulated to in comments within a FERC Technical Conference on Resource Adequacy in the Evolving Electricity Sector:

> Given the ongoing evolution of the markets, we believe that we and our stakeholders should evaluate the need for procurement of additional reliability attributes, such as ramping, flexibility and inertia that may be required for a system with increased intermittent and distributed energy resources. Resource adequacy in the future should no longer be measured based solely on the characteristics of the peak day; it must evolve to include the ability to serve load in all hours of the year.
>
> — ***PJM Interconnection*** [90]

The PJM Board of Directors has also directed PJM staff to examine future system reliability needs alongside a series of other related reforms to the capacity market, with a stakeholder process set to begin in the Operating Committee in Fall 2021.[91]

Many regions across the globe are engaging in similar assessments of future system reliability needs in decarbonized systems and so provide a rich basis to draw from on the nature of grid reliability services that could be needed, how to determine the quantity of these products that might be needed, how to procure them, and how to enable emerging technologies to compete. Some of these new reliability products have already been implemented and offer lessons learned, though others are either in proposal or early deployment stages. In general, the approaches to addressing emerging reliability needs include the following steps (though when some steps are skipped, there can be implementation flaws):

[90] See PJM, "Statement of PJM Interconnection", created for and presented to the FERC Technical Conference on Resource Adequacy in the Evolving Electricity Sector, March 23, 2021, p.8.

[91] See Almgren, PJM Chair, April 2021 Letter to Stakeholders, April 6, 2021 and Keech, Capacity Market Reform Committee Presentation, August 2021.

1. **Assessing the nature of reliability needs** using a forward-looking study of the system as it decarbonizes, focusing on issues of system security, flexibility needs, net load forecast uncertainties, the difference in the level of system uncertainties if distributed resources are visible and controllable (or not), and daily/seasonal patterns in needs and resource availability to identify how patterns of resource shortage may evolve in the future. Permanent changes to weather patterns associated with climate change and consumption patterns as associated with electrification will tend to cause new and different reliability needs than those experienced in the past.
2. **Reviewing existing market incentives to identify gaps** as to: (1) whether investment incentives across the energy, ancillary, capacity, and clean/policy markets will be sufficient to attract and retain the mix of resources needed to maintain reliability; and (2) even if the needed resource mix is available, to ensure that a sufficient share of dispatchable supply will be online and available to meet system needs and manage uncertainties in the operating timeframe.
3. **Translating any reliability gaps into defined products** with clear units of measure, qualification standards, commitments, and operating procedures. In some cases, the reliability gap can be filled by increasing the volume of procurements from existing or slightly revised products, while in other cases an entirely new product must be defined. This product definition stage should also consider the overlap between system needs and the services that alternative resources can provide, to ensure that the maximum number of resources and resource types can compete to provide system reliability needs.
4. **Determining the volume needed from each product** using a study of system needs or variability.
5. **Estimating the value of the product** to determine the maximum willingness to pay that should be expressed through market (see Section V.B).
6. **Establishing a mechanism for procuring the reliability service in the operating timeframe**, first and foremost through the energy and ancillary services markets that are the primary markets through which system reliability needs can be expressed and met.
7. **Determining whether forward procurement is necessary** for some products. The large majority of system reliability and operability needs can be met through the non-forward energy and ancillary markets by ensuring that available resources are online and providing the needed services. These energy and ancillary service markets also provide an incentive to attract and retain more flexible resources, and for resources such as DERs that are not currently visible and controllable by the system operator to *become* visible and controllable if they are technically capable of doing so (so that they can earn payments for contributing to system reliability). If, even after these needs are fully reflecting in the energy and ancillary service markets, the system operator is concerned that insufficient resources will be developed to provide the needed reliability services, then commitments to retain and develop these resources can be procured on a forward timeframe within the capacity market (see Section V.C
8. **Ensuring that all resources are able to compete to provide the defined product**, as discussed in Section IV.

The series of studies conducted in Australia's National Energy Market within the Future Power System Security Program provides a number of examples of the types of analyses that could be needed to asses emerging reliability needs.[92] One of these studies included an international survey of reliability assessments in decarbonizing systems to determine the common reliability needs that have emerged in other contexts as summarized in Table 5.[93] The survey identified several common themes including that: (a) integrating high levels of distributed resources will require an increasing level of visibility, predictability, and controllability of these resources, so that they can become an asset toward managing system reliability needs (rather than an additional uncertainty that must be managed against; (b) managing system uncertainties and variabilities will become increasingly important and may require new balancing products such as to meet ramping needs; and (c) frequency management will become increasingly challenging and may require additional inertia or fast frequency response at varying time scales. The study also

[92] See the suite of studies and initiatives at Australian Energy Market Operator's Future Power System Security Program.

[93] See Australian Energy Market Operator, "Maintaining Power System Security with High Penetrations of Wind and Solar Generation", October 2019.

found that the particular solutions most beneficial in each region would be tied to the specifics of their resource mix and context. Australia has further refined its understanding of its own system needs and is in the process of reforms to define and introduce new products including a ramping product.[94]

TABLE 5. EMERGING RELIABILITY NEEDS IDENTIFIED IN HIGH RENEWABLE SYSTEMS

			Defined system limits that impact renewables				
System Attribute	**Requirement**	**Focus Area**	**Eastern Australia**	**Western Australia**	**Ireland / Northern Ireland**	**Great Britain**	**Texas**
Frequency Management	*Maintain frequency within limits*	*Primary Frequency Response Enabled*	See full report				
		Synchronous Inertia	○	○	●	○	●
		Rate of Change of Frequency	○	○	●	●	○
Voltage Management	*Maintain voltages within limits*	*Voltage*	◐	◐	◐	◐	◐
	Maintain stability of system	*System Strength Bulk System*	●	○	○	○	○
	Maintain stability of individual generating system	*System Strength Generation Connection*	◐	○	○	○	◐
Other	*Maintain system in secure state*	*System Variability*	○	○	◐	◐	◐
		Minimum Synchronous Unit Combinations	●	○	●	○	○
		System Non-Synchronous Penetration	○	○	●	○	○
		Distributed Energy Resources	○	○	○	○	○

● Limit specified which currently limits the penetration of wind and solar
◐ Limit specified which may indirectly limit penetration of wind and solar
○ No specified limit

Sources and notes: Adapted from See Australian Energy Market Operator, "Maintaining Power System Security with High Penetrations of Wind and Solar Generation", October 2019, Table 1 (p.15).

One potential new ancillary service product that may be needed for reliability that emerging technologies including DERs can provide is "ramp". Several other regions with high levels of renewables are in the process of designing or have already implemented different variations of this product including in Midcontinent ISO, California, Australia, Southwest Power Pool, and Texas.[95] Though the exact approach and parameters used differs in each market, the general concept is illustrated in Figure 13 for a 10-minute ramping product. The ramping product is used to ensure that the system operator always holds enough resource capability to meet upcoming ramping needs (including to meet both the expected and uncertainty band around system ramping needs) over future 5-minute dispatch intervals. If net ramping requirements are higher than expected, the available ramp-up-capable resources can be called on to meet the higher ramping needs. Ramp-up products add value by avoiding short-term reliability shortfalls, managing system uncertainties, improving price formation, and reducing out-of-market payments that would otherwise be made (usually to fossil resources) to meet unexpected ramping needs. Ramp-down products add value by reducing the level of renewable curtailments that can be induced in low-demand periods. Further, ramp-up and ramp-down products are a natural fit for attracting more participation, visibility, and system controllability from the emerging resources needed to meet the District's clean energy future.

Ramping products are a natural fit for attracting demand response, batteries, electric vehicles, and other distributed resources (even, to some extent, renewables) to provide higher flexibility value to the bulk grid. Many of these

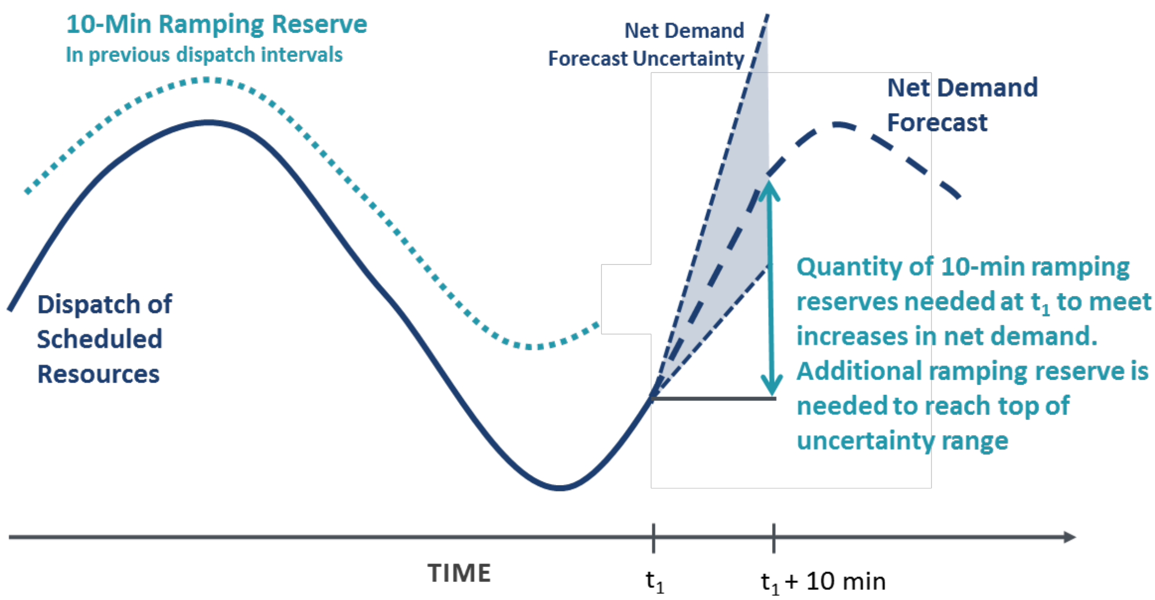
---

[94] See, for example: Australian Energy Market Operator, *Power System Requirements*, October 2019 and the Australian Energy Market Commission's Operating Reserve Market Project Details.

[95] See a more comprehensive discussion of ramping products within the Southwest Power Pool context in Pfeifenberger et al, *Initial Comments on [Southwest Power Pool's] Draft Ramp Product Report*, August 30, 2018.

resources are or can be adapted to become highly flexible and can respond quickly to manage system ramping and uncertainty needs on short timescales, and in that respect are a likely source of low-cost supply to provide this service. Further, because the procurement of ramp can be done on an in-market basis, this will reduce the tendency for the system operator to require out-of-market dispatch and uplift payments to fossil resources that may otherwise be needed to meet urgent ramping needs. Thus, ramping can serve multiple objectives including improving reliability, reducing costs, enhancing visibility and controllability of emerging resources, and reducing renewable curtailments.

FIGURE 15. NEW "RAMPING" RESERVES PRODUCT CAN BE USED TO MANAGE SYSTEM VARIABILITY



Source: Adapted from Navid & Rosenwald, *Ramp Capability Product Design for [Midcontinent ISO] Markets*, December 22, 2013.

First and foremost, system flexibility needs should be reflected in the operational timeframe through improvements to energy and ancillary services markets. However, it is also essential that the forward capacity market has an accurate representation of the reliability needs in expectation over the year, so that the market can procure a fleet of resources that will collectively serve resource adequacy objectives. The traditional approaches to assessing long-term resource adequacy needs have focused primarily on meeting summer peak needs, which has always been the driver of supply shortfalls in the past.

Going forward however, a more comprehensive assessment of reliability needs will be required to ensure accurate accounting of reliability contributions from all resources in the capacity market. PJM is already pursuing reforms to more accurately represent reliability contributions of renewable and battery resources through its recently-approved proposal to adopt an ELCC approach to accrediting these resources in the capacity market.[96] However, this same concept has not yet been applied to all resource types, such as fossil resources that do not have firm winter fuel capability and so may not be available to meet winter needs.[97]

Another new reliability service that may be needed and that could be provided by clean energy resources such as batteries and dispatchable demand response is flexible capacity. To date, the capacity market in PJM has not considered the need for *flexible* capacity (which, for this discussion, we define as capacity sufficient to meet all system ancillary service and balancing requirements, plus an uncertainty margin). If a system has enough supply

96 See FERC's eLibrary entry for "Order Accepting Tariff Revisions and Terminating Section 206", July 30, 2021.

97 In the 2014 winter vortex for example, PJM documented 40,200 MW of plant outages (22% of the fleet at the time), of which 9,300 MW were gas supply outages, and the majority of others were cold-weather-associated forced outages. Though some reforms including the new Capacity Performance product that imposes strong penalties for non-availability during such events have likely partly addressed such availability concerns, the concept has not been adapted into revised capacity ratings for such resources. See PJM, "PJM Cold Snap Performance Dec. 28, 2017 to Jan. 7, 2018", February 26, 2018.

but that supply is not sufficiently flexible to manage uncertainties, that can drive operational shortages. California and Greece are two regions that have introduced the concept of "flexible capacity" requirements in their resource adequacy mechanisms as a means to ensure that there will be both sufficient supply and sufficient flexible supply.[98] The version of "flexible capacity" needs defined in these other jurisdictions would be unlikely to match the needs in PJM, but the concept should be considered as an option. If flexibility needs are already fully expressed through energy and ancillary services markets, but total investment signals appear insufficient to attract the needed level of flexible resources, then the "gap" in available resources can be reflected as a requirement within the capacity market. Less-flexible resources such as coal plants, nuclear, and renewables may not qualify to provide this service (or may qualify to provide only a small amount); while more flexible resources such as batteries and dispatchable demand response would qualify and could earn a premium in the capacity market.

OPPORTUNITIES TO ADVANCE POLICY PRIORITIES

To maintain reliability throughout the clean energy transition, the starting point is to have an accurate, forward-looking assessment of emerging system reliability needs and a feasible plan for meeting reliability needs entirely with clean energy resources (at least in deeply decarbonizing subregions of the PJM system). A program of work to that end could include:

- **A comprehensive set of forward-looking assessments of emerging reliability needs**, building on the analyses described in Section IV above and as conducted in several other jurisdictions. In particular reviewing the potential need for:
  - Ramp-up and ramp-down products at varying operational timeframes,
  - Whether and when additional products may be needed to manage frequency, or
  - Other possible reliability products as portions of the system undertake clean energy transition.
- **Assessing how these needs can be met through higher quantities of existing ancillary products, or introducing new ancillary services products,** considering product definitions that will enable the widest array of existing and emerging clean resources to participate.
- **Developing methods to regularly assess the volume and value of existing and new ancillary services** products so that they can be incorporated into energy and ancillary service market dispatch (see Section V.B).
- **Revising approaches to assessing resource adequacy needs and resources capacity ratings** so as to account for both system needs and resources' capability as driven by seasonality, intermittent resource variability, resource flexibility, and firm fuel capability. Apply the concept of ELCC to all resource types, including resources that are less operationally flexible and that may be fuel-limited during winter peak times (see Section V.C).
- **Evaluate whether there is a need to implement flexible capacity requirements** within the capacity market, particularly once energy and ancillary markets are fully reflective of operational needs and if an insufficient quantity of flexible resources is still anticipated.

[98] See California ISO, *Final Flexible Capacity Needs Assessment for 2022*, May 14, 2021 and EnergyPress, "EC approves Greek support mechanism for flexible power capacity", July 31, 2018.

B. Energy and Ancillary Service Market Enhancements

CHALLENGES WITH CURRENT PRACTICE

Once emerging system needs are defined and translated into a suite of reliability products, they must be incorporated into energy and ancillary service market design. The software systems underpinning the wholesale markets are highly complex and expensive, meaning that reforms to enhance them must consider the cost, feasibility, sequencing, and other pragmatic issues that tend to limit the pace of change. Achieving the greatest value within these limits likely requires a clear understanding of where the overall market design needs to bee in ten years, and pursuing the highest-impact reforms toward that end. In some cases an approximated approach that fits within the current software framework is more useful than a more elegant solution.

Developing the most efficient prices within the energy and ancillary service markets has been a challenging aspect of wholesale energy markets from their inception. One reason that prices are challenging to set is that there has not historically been an active demand side to the market that can provide a clear measure of the willingness to pay for energy or reliability. Further, even the demand response resources that exist and are available have utilized special arrangements that tend to be hard to fully integrate into energy and ancillary market dispatch and price formation.

In the future there *will* be an active demand side, but market systems will need to be enhanced so as to better incorporate these resources into system dispatch and wholesale market price formation. A wide array of demand response, batteries, and aggregated DERs can express their ability to shift consumption and charging loads, and so these resources' capabilities will need to be better integrated into price formation at all market timeframes. At the same time, the advance notification required for some of these resources will need to be reflected (similar to how long start-up times are accommodated for traditional thermal plants).

The importance of full integration of emerging clean technologies into market dispatch and price formation can sometimes be lost in the complexity of these markets, but will be a critical component of achieving decarbonization reliably and affordably. If emerging reliability needs are not adequately reflected and clean resources are not sufficiently integrated, the market will likely face increasing instances of flexibility-driven supply shortfalls, out-of-market dispatch instructions, and increasing volumes of uplift payments.

> Full integration of emerging clean technologies into market dispatch and price formation is a critical component of reliable, affordable decarbonization. Otherwise, the markets could face increasing instances of flexibility-driven supply shortfalls and out-of-market reliance on traditional fossil plants to address these reliability events.

Out-of-market uplifts tend to be a signal that something is "missing" in the market because the system operating needs to pay resources outside the market to remunerate dispatch instructions that are not incentivized by prices alone.[99] For example, in 2020 the largest out-of-market uplift payments in the PJM system were $58 million in "balancing generator" uplifts (91% of which were paid to gas combustion turbines, for example to compensate for their fast-start capability that is not fully reflected in market prices); $19 million in "lost opportunity cost" uplifts (94% paid to gas combustion turbines, generally to compensate them for "holding back" capacity to meet energy needs in future dispatch intervals); and $9 million in uplifts to "day-ahead generators" (91% of which were awarded to coal plants, again compensating for costs such

[99] Uplift payments are payments made to resources that have been instructed by PJM to operate in a way that requires them to incur costs that are not recovered through competitive market prices. Uplift or top-up payments are awarded to encourage market participants to follow dispatch instructions, even when market prices would incentivize different behavior. The need for uplift payments generally indicates imprecision in market prices or a grid reliability service that is needed but not properly reflected and remunerated through the competitive markets.

as start costs that are not fully reflected in energy prices).[100] These uplift payments have at some level been accepted as an unavoidable nuisance that must be tolerated to compensate for the complexities of the large wholesale market, including accounting for the “lumpy” nature of traditional fossil generators’ on-off decisions and other operating parameters.

But these uplifts also signal some deeper inconsistencies with the clean energy transition, including that: (a) nearly all of these uplifts are awarded to fossil plants (not to clean energy resources), (b) many of these uplifts are generally awarded to resources as a consequence of their *inflexibility*, such that the market does not currently create incentives for fossil plants to become more flexible (for example by reducing their minimum generation levels), and (c) because the payments are made on an out-of-market basis rather than through in-market prices, this limits the opportunity for more flexible clean resources to provide the needed energy or balancing capability at a lower cost.

ONGOING REFORM EFFORTS AND POTENTIAL SOLUTIONS

As discussed in Section V.A, energy and ancillary service markets will need to be reformed to incorporate higher volumes and new types of ancillary services, express a willingness-to-pay for these services in market clearing software, and procure these resources in a co-optimized fashion alongside energy within the real-time and day-ahead markets. The PJM energy and ancillary service market software can implement these reforms, though even seemingly small reforms can be quite complex and time-consuming. Amongst the ongoing reforms to pursue these ends include PJM’s new “fast start pricing” approach that will better integrate the start-up costs of gas combustion turbines into price formation and the new operating reserve demand curve (ORDC) approach that will pay to hold higher quantities of reserves online to help manage system variability.[101] Both of these reforms, as well as the concurrent changes to increase the volume of reserves procured to manage system variability, will tend to address some of the challenges outlined above with respect to uplift payments and continued reliance on fossil plants to meet reliability needs.

Though there is not sufficient operating history in PJM to determine how extensively they will address historical challenges with uplifts, we anticipate substantial improvements. However, ongoing additional reforms are likely to be needed to more tightly tie the nature of procured reliability services to system needs, and the value of these services. For example, the value of maintaining contingency reserves and ramp-up needs could be tied to the value of lost load (VOLL) if falling short of these reserves would mean interrupting firm customers (for example, a probabilistic fraction of a typical VOLL in the range of $10,000/MWh); while the value of ramp-up reserves could be more modest at the probability-adjusted avoided cost of dispatching fast-start combustion turbines (for example, a probabilistic fraction of a $500/MWh dispatch price). The value of ramp-down reserves would likely be tied to the probability and value of avoiding renewable curtailments. The specific nature and need for each type of reliability services will tend to dictate the value that should be incorporated into the PJM software as either an ORDC or penalty factor that reflects the value that the system and customers should be willing to pay to maintain these reliability services. If new products such as ramping would be introduced, this may enable reducing volumes of other types of reserves that are meant to serve different purposes. Finally, a critical element of ongoing reforms will need to be confirming that clean and emerging resources are able to provide these services, assuming they have the technical capability to contribute to system reliability.

[100] See Monitoring Analytics’ 2020 State of the Market Report for PJM, table 4-3 (p.239).

[101] See FERC “Order Addressing Arguments Raised on Rehearing”, November 3, 2020; PJM Market Implementation Committee, “Operating Reserve Demand Curves (ORDC) for Reserve Price Formation Project”, April 7, 2021; PJM, ”Enhanced Price Formation In Reserve Markets Of Pjm Interconnection, L.L.C.”, March 29, 2019; and PJM Market Implementation Committee, “Fast Start Education”, October 19, 2020.

OPPORTUNITIES TO ADVANCE POLICY PRIORITIES

Continued enhancements to the energy and ancillary service markets and associated price formation mechanisms will tend to support the District's goals to achieve clean energy transition. To maximize consistency with that vision, PJM could:

- **Monitor and address the underlying causes of uplift payments**, particularly the largest of these uplift payments, those that may be increasing over time, and those that are awarded to fossil resources. These causes of uplift payments may suggest additional opportunities to reflect system needs within the wholesale markets through improved definition of ancillary service needs, improved price formation, and/or opportunities to expand opportunities for emerging flexible resources, including DERs.
- **Continue to refine the understanding of reliability service needs and incorporate these into the wholesale market,** while considering the substitutability of some services, to avoid over-procurement in total across all ancillary services
- **For each existing and new ancillary service, develop a "willingness to pay"** that is more tightly tied to the need and value of each product, whether that need arises from avoiding outages, avoiding out-of-market unit commitments, or avoiding wind curtailments. As PJM has already considered in implementing the ORDC, this willingness to pay tends to decline as the market procures higher volumes of a particular reserve
- **Ensure that clean and emerging technologies** are enabled to compete to sell these services if they are technically capable, without facing excess transaction costs or barriers to entry. Given that batteries, demand response, and many types of aggregated DERs are likely to be a natural fit to provide these services, track the pace of entry and participation in these markets and their incorporation into market price formation. If entry is lagging, use pilot programs or other reviews to determine whether there are participation barriers that can be removed.

C. Seasonal Capacity Market

CHALLENGES WITH CURRENT PRACTICE

The PJM capacity market was originally implemented as an annual construct because the summer season has historically had both the highest demand and shortest supply. Thus, ensuring sufficient quantities of capacity in the summer would ensure sufficient quantities of supply would be available for the entire year. However, significant changes to the resource mix and the nature of reliability concerns in both seasons have introduced a more prominent need to establish resource adequacy in both the summer and winter seasons. To address winter supply adequacy and enable summer resources, PJM has introduced a series of reforms, from the prior summer-only demand response program, to Capacity Performance, to a resource matching mechanism for some seasonal resources.

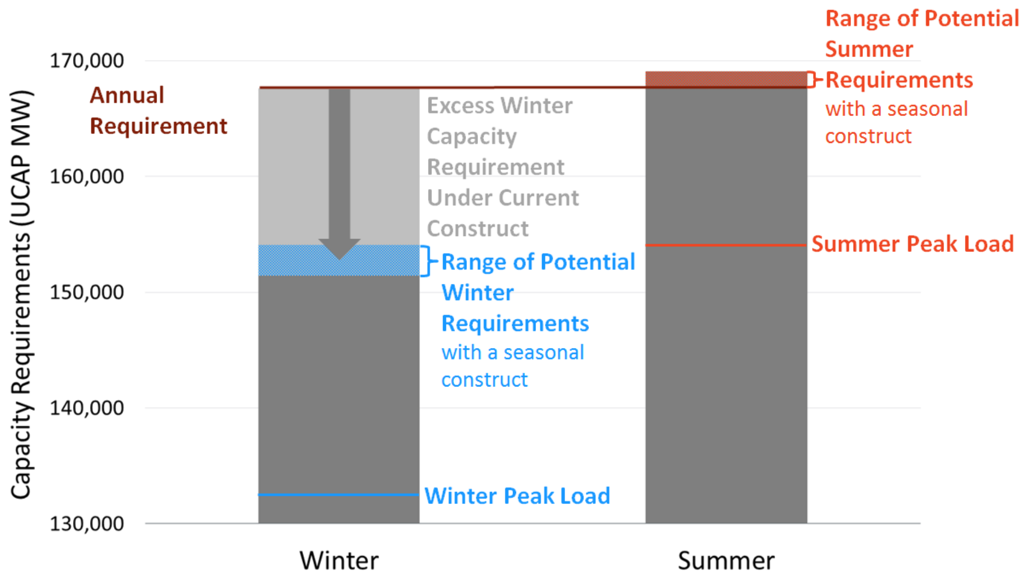
Despite these reforms, the current PJM capacity market design does not yet offer a robust assessment of winter (or other non-summer) resource adequacy needs, and does not yet enable the full participation of seasonal capacity resources. As illustrated in Figure 16, the PJM capacity market maintains an annual design (red line at top). However, PJM has previously conducted an assessment of winter resource adequacy needs and determined that a separate winter requirement would be approximately 14,000 to 16,000 UCAP MW lower (blue area below arrow).[102] Under the current construct, summer-only capacity cannot participate without being matched with an equivalent amount of winter-only capacity. This results in inefficiently little reliance on summer-only resources, and inefficiently high

[102] See PJM, Winter Season Resource Adequacy Analysis, February 2, 2018. The range corresponds to the requirements under Scenario 5A, as discussed in the main text.

procurement of annual capacity. Despite the excess procurement of notionally annual and winter-capable resources, there may still be reliability risks in winter that are not fully understood because the market does not incorporate comprehensive mechanisms for measuring the reliability value of all resources in winter, such as by accounting for fuel security during extreme cold events.

For the resources envisioned to meet the District's clean energy needs in the future, a two (or more) season capacity market would offer a better opportunity to integrate and remunerate these resources. Solar, wind, demand response, and energy efficiency resources all tend to have significantly different levels of availability and reliability value across seasons, meaning that a seasonal market would offer greater opportunities to offer the full resource capability (rather than the minimum of the two-season capability).

FIGURE 16. SUMMER AND WINTER PROCUREMENT UNDER THE ANNUAL CAPACITY MARKET IN 2020/21



Sources and Notes:
See Newell, et al, "Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM", April 12, 2018.

ONGOING REFORM EFFORTS AND POTENTIAL SOLUTIONS

For several years after the shortage events caused by extreme winter weather after the 2014 polar vortex, PJM engaged in several reforms to examine the need for supports to maintain winter reliability and examined alternative approaches to supporting winter resource adequacy. Though several enhancements were made to the market design in response to these events, the reforms stopped short of adopting a full seasonal capacity market design.[103] More recently, the PJM Board has identified a seasonal capacity market as amongst the reforms that should be considered within the context of capacity market evolution in the proceedings to be conducted in the latter half of 2021.

Since that time, Ontario has implemented a two-season capacity auction, and Midcontinent ISO has proposed to pursue a four-season design.[104] In both of these regions, clean energy transition and enabling emerging technologies is a substantial factor in the consideration of a seasonal design. For example, Midcontinent ISO, like PJM, has historically faced the tightest supply conditions in summer, but in a recent analysis of year-round resource adequacy

[103] See O'Konski and McCormick (Washington Energy Report), "FERC Denies Complaints Against PJM's Seasonal Resource Participation Rules", June 4, 2020.

[104] See IESO, *Market Manual 12.0: Capacity Auctions*, December 2, 2020 & Midcontinent ISO, "Resource Adequacy Reforms", August 4, 2021.

needs has identified substantial increases in reliability events across all four seasons (though the drivers of these shortfalls vary by season and by location).[105] A seasonal construct can perform better than an annual construct because it offers:

- **More accurate reliability needs assessments** across system conditions that can vary substantially across the year in high renewable systems,
- **More accurate accounting of resources' reliability contributions** that vary by season (but in a pattern that does not necessarily match consumption patterns), particularly for many clean energy resources including solar, wind, hydropower, demand response, and energy efficiency,
- **Greater flexibility to adapt to changing demand patterns associated with electrification,** particularly the outlook for higher winter demand as heating loads become electrified,
- **Better price formation across seasons** by creating as structure that can separately quantify and price resource adequacy value across the seasons, sending more targeted signals to develop and retain the types of resources most needed to meet needs in the tight seasons, and
- **Lower overall costs** associated with improved incentives, a more efficient resource mix, and lower total procurement levels.

The approach to a two-season capacity auction that has been implemented in Ontario is similar to a concept that has been previously considered in the PJM context.[106] The concept of that two-season capacity auction design is to establish separate reliability requirements in the summer and winter seasons, and award each capacity resource separate capacity ratings in the two seasons. As illustrated in Figure 17, separate demand curves would be established to reflect the different procurement volume in each season (acknowledging that less supply must be procured in winter than in summer). The auction would be conducted similarly to how it is implemented today but with alterations to optimize capacity procurements across the two seasons. All resources would be able to offer into the auction in up to three ways as: (a) summer-only offers (based on summer UCAP MW ratings), (b) winter-only offers (based on winter UCAP MW ratings), and (c) annual offers, submitting a total annual payment requirement to clear both summer and winter UCAP at different MW rating levels. The auction clearing engine would select the lowest-cost set of summer, winter, and annual resources to meet both seasons' capacity needs, with prices set separately in each season based on the incremental cost of purchasing more capacity in that season.[107] Payments would not be automatically split 50/50 between the two seasons, but rather the relative price levels would align with distinct supply-demand conditions across the two seasons. If adopted in the PJM region, a seasonal capacity auction could achieve long-run societal benefits of roughly $100–600 million per year compared to the current annual design.[108]

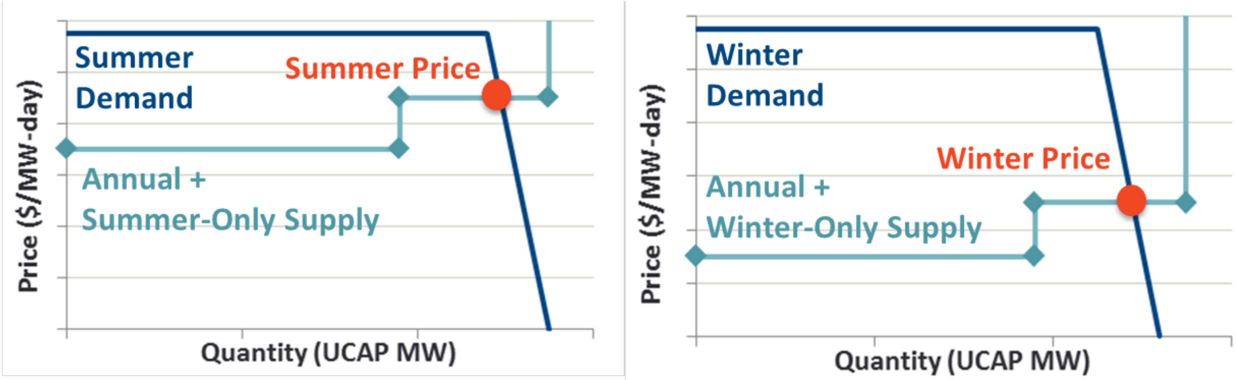
[105] See Midcontinent ISO, "Resource Adequacy Reforms", August 4, 2021.

[106] See Newell, et al, "Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM", April 12, 2018.

[107] If a summer-only resource is marginal in summer, then the summer clearing price would be that resource's offer price (similarly if a winter-only resource is marginal in winter). If an annual resource is "marginal" then the total clearing price across the two seasons would equal its annual offer price, though the optimization algorithm would determine the split of these payments across the two seasons.

[108] See Newell, et al, "Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM", April 12, 2018.

FIGURE 17. SUMMER AND WINTER CLEARING RESULTS IN A TWO-SEASON CAPACITY MARKET



Source: Adapted from Spees, et al. "ICA Demand Curve Analysis: Preliminary Findings Regarding the Demand Curve for a Two Season Auction," prepared for the Independent Electricity System Operator of Ontario. October 2018.

OPPORTUNITIES TO ADVANCE POLICY PRIORITIES

Transitioning to a seasonal capacity auction design in the PJM market has the potential to improve reliability, reduce costs, and enable more seasonal clean energy resources. Implementing a seasonal capacity market would involve:

- Conducting a forward-looking assessment of resource adequacy needs after considering a range of resource mixes that may evolve in the PJM region and in subregions that are in the midst of clean energy transition. The analysis would use best practices in resource adequacy assessments to establish the level of reliability needs (and differences in resources' capabilities) across the year to determine which seasons would be the most important to represent from a reliability perspective,
- Applying the ELCC concept to all resource types to develop accurate reliability-based capacity ratings for all resource types in each season, including ensuring that all types of clean and emerging resources are enabled to participate to provide full capacity value, and
- Enhancing the PJM auction procurement platform to optimally procure and price capacity across each defined season, so as to produce separate prices reflecting the value of capacity in each season.

Appendix: Description of the Regional Capacity Market

PJM's capacity market, the Reliability Pricing Model (RPM), is a market-based system for securing capacity resources to meet system and locational reliability needs. The quantity of capacity procured must be sufficient to meet a reliability standard of no more than *one expected loss-of-load event in ten years* (0.1 LOLE or 1-in-10). PJM establishes a reliability requirement based on forecasted peak load plus the installed reserve margin (IRM) needed to maintain 1-in-10 reliability. Through a three-year forward competitive Base Residual Auctions (BRAs), the capacity market procures sufficient generation, storage, or demand response to meet reliability needs at the lowest possible cost. The RPM uses locational pricing that reflects transmission system limitations and uses a pay-for-performance incentive structure to incentivize resources to deliver on their capacity commitments during reliability events.

An administratively-determined Variable Resource Requirement (VRR) curve is used to characterize demand needed to procure sufficient capacity to maintain resource adequacy under the RPM, as illustrated in Figure 18. The VRR is a downward-sloping, segmented demand curve that specifies the prices and demand relative to the IRM.[109] Prices in the VRR curve are tied to the administrative estimate of the Net Cost of New Entry (Net CONE)[110] which is the price at which new generation resources would be willing to enter the market. System wide and locational VRR curves are designed to allow for the procurement of sufficient capacity to achieve resource adequacy, mitigate price volatility, and mitigate the ability for sellers to exercise market power.[111] Market participants with existing resources are required to offer available capacity into the RPM. New resources may also offer into the market as price takers or at prices that reflect their individual net costs of entering.[112] The intersection of market participant supply offers and the VRR curve in each location sets the market price paid to all cleared capacity resources for the relevant one-year delivery period in that location. Supply resources unable to meet their capacity commitments are subject to deficiency and penalty charges. RPM prices are designed to be consistent with supply-demand conditions; the RPM produces low prices when there is more than enough supply to meet resource adequacy needs and high prices when capacity supply is scarce.

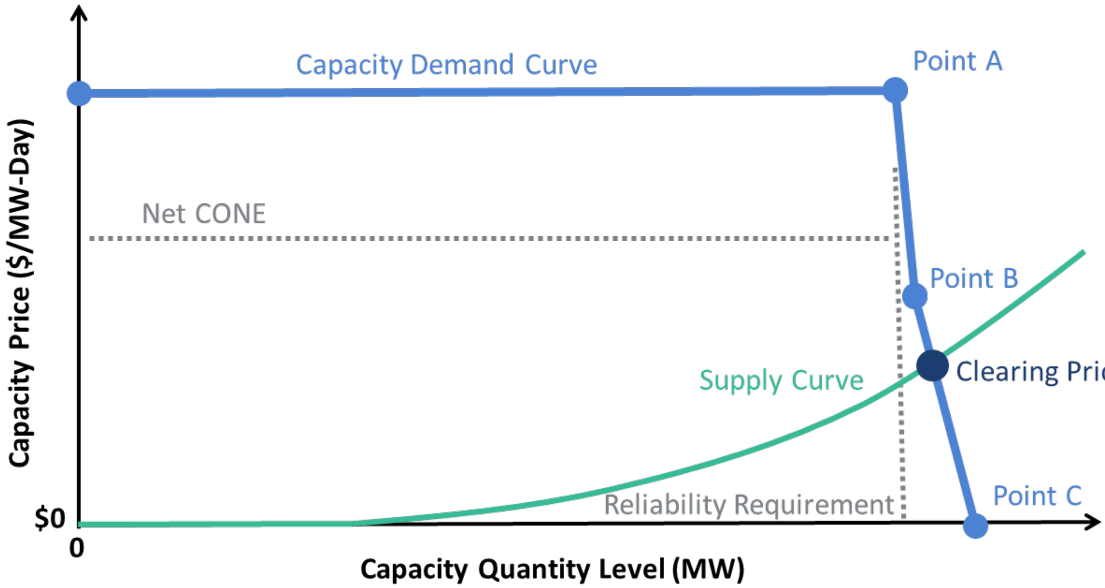
[109] PJM Interconnection Capacity Market & Demand Response Operations, "PJM Manual 18: PJM Capacity Market," Revision 47, January 27, 2021, Section 3.

[110] Net CONE is the capacity revenue needed by a new generator to become economically viable in its first year of operation.

[111] Samuel Newell *et al.* "PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date," April 19, 2018.

[112] Seller offer prices are driven primarily by their going-forward investment and fixed costs minus any net revenues they anticipate to earn from selling other products such as energy, ancillary services, or RECs. Many capacity resources offer at a zero price if they have already come online and have few going-forward capital investments or can pre-sell most of their capacity or energy through bilateral contracts. Participants may also adjust their capacity offer price based on their long-term view of future energy and capacity prices.

FIGURE 18: ILLUSTRATIVE PJM CAPACITY SUPPLY AND DEMAND CURVES



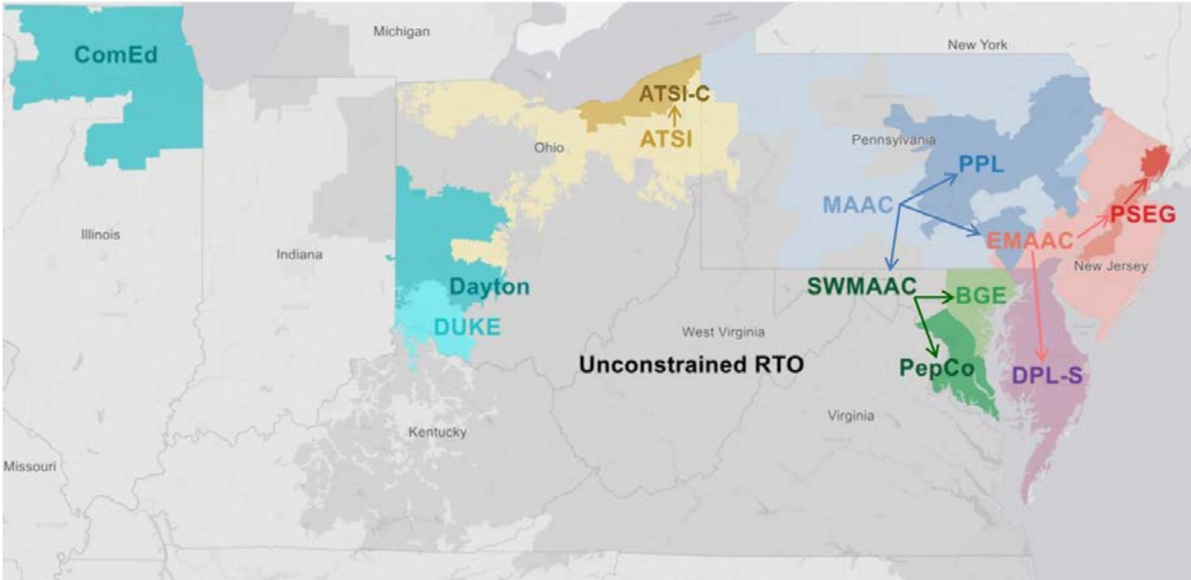
Notes: Illustrative, not drawn to scale. *See* 2022/2023 RPM Base Residual Auction Planning Parameters for specific demand curve parameters.

Historically, the PJM capacity market has been able to attract new investment and procure capacity that exceeds the reliability requirement, and at prices below the administrative estimate of Net CONE. Since the 2007/08 delivery year, 62,000 MW of new generation capacity has been attracted into the PJM capacity market; including more than 11,000 MW from uprates to increase the output capability of existing resources. Beyond these additions of generation capacity, RPM has attracted other sources of capacity supply. Demand response and net import capabilities in PJM have also increased by an additional 10,100 MW and 8,700 MW, respectively. These incremental capacity resources have been sufficient to meet increases in regional demand and replace large quantities of retirements from aging coal, nuclear, oil-fired, and high-heat rate natural gas plants.[113]

PJM uses the capacity market to procure capacity across the region to meet system-wide and local reliability needs at the lowest possible cost. Subregions of PJM with limited import capability due to transmission constraints are modeled as separate Locational Deliverability Areas (LDAs). Figure 19 shows a map of LDAs that are currently modeled in the RPM.

[113] PJM Interconnection, "2022/2023 RPM Base Residual Auction Results," June 2, 2021, pp. 20, 22, and 24.

FIGURE 19: MAP OF MODELED LOCATIONAL DELIVERABILITY AREAS IN PJM



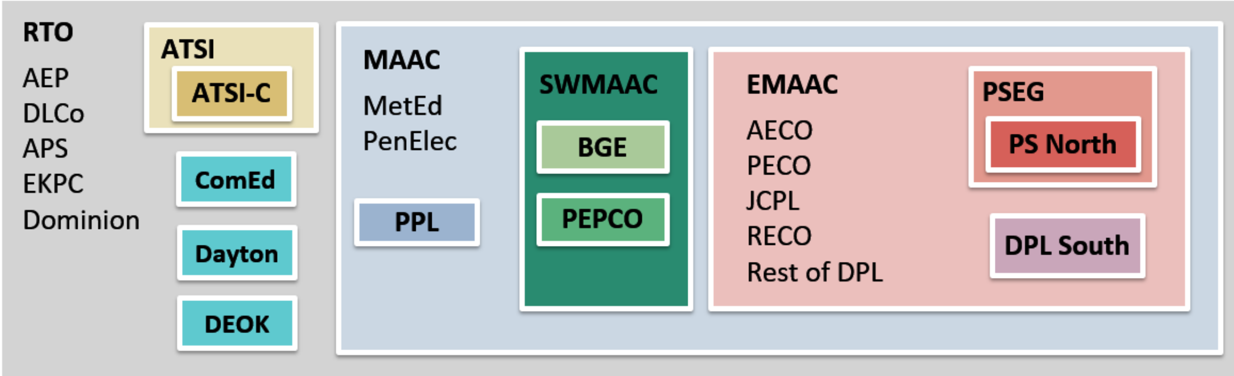
Sources and Notes: Samuel Newell *et al.,* "Fourth Review of PJM's Variable Resource Requirement Curve," April 19, 2018, Figure 1. The map represents modeled LDAs as of 2022/23.

Modeled LDAs each have a locational VRR curve, local Reliability Requirement, and locally estimated Net CONE. A "nested" LDA structure is used to reflect the transmission topology across the PJM system, in which successively smaller LDAs can procure capacity locally or from larger "parent" LDAs. Each LDA must have enough capacity procured to meet the local reliability requirements but can import a portion of that capacity from the parent LDA up to the maximum quantity that the transmission system can support or the Capacity Emergency Transfer Limit (CETL).[114]

This complex transmission topology is illustrated in Figure 20. Modeled LDAs in the capacity market do not always align with utility service territories or state boundaries. The Potomac Electric Power Company (PEPCO) includes all of the District and parts of Maryland. The District's capacity needs can also be meet through imports from its parent LDAs, Southwestern Mid-Atlantic Area Council (SWMAAC), and Mid-Atlantic Area Council (MAAC), and the broader unconstrained regional transmission organization (RTO) region. Each modeled LDA has separate reliability parameters that must be achieved and each may produce distinct capacity clearing prices. The RPM reflects these transmission constraints within auction clearing by optimizing capacity imports to meet the reliability needs of all LDAs at the lowest cost. By participating in a broad regional marketplace, the District can save costs by importing lower-cost capacity from parent LDAs (to the extent possible) while ensuring that sufficient local capacity will be available for reliability needs.

[114] *See* "Special Planning Committee: CETO/CETL Education," PJM Interconnection LLC, accessed May 7, 2021.

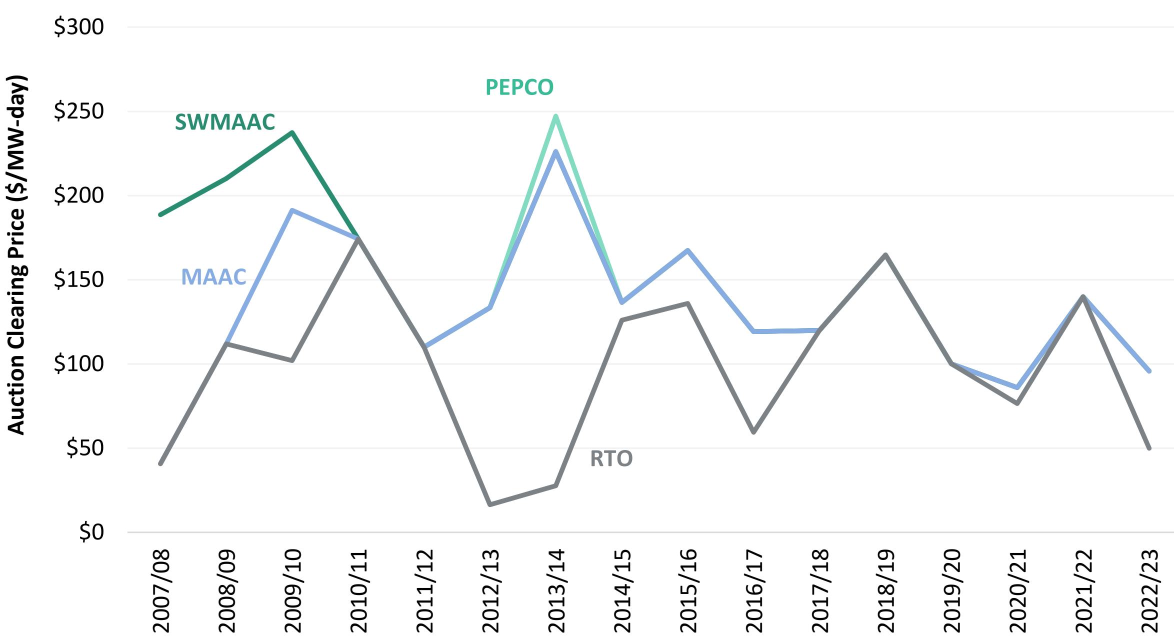
FIGURE 20: SCHEMATIC OF NESTED STRUCTURE OF LOCATIONAL DELIVERABILITY AREAS



Sources and Notes: The nested schematic is from Samuel A. Newell *et al.*, "Fourth Review of PJM's Variable Resource Requirement Curve," April 19, 2018, Figure 10. Each rectangle and bold label represent an LDA modeled in the 2022/2023 RPM Base Residual Auction Planning Parameters; individual energy zones listed in non-bold without boxes are not currently modeled. See PJM service area map for full LDA names.

Under the RPM pricing structure, import-constrained LDAs can experience higher clearing prices relative to their parent LDAs due to transmission limits and tight local supply-demand balance. Figure 21 shows PEPCO rarely experiences higher clearing prices relative to its parent LDA, SWMAAC. The smaller LDAs have equal or higher prices as compared to the parent zones and can produce occasional price spikes due to the relatively large price impact from small changes in supply, demand, and transmission parameters. Higher prices in constrained LDAs can serve as a signal to attract new investment in supply resources that are needed to support local reliability requirements, even though developing capacity resources may be more expensive in these locations.

FIGURE 21: CAPACITY CLEARING PRICES FOR THE LDAS SERVING WASHINGTON, DC



Sources and Notes: Capacity clearing prices are from Monitoring Analytics, "2019 State of the Market Report for PJM: Volume II, Section 5 – Capacity Market," March 12, 2020, Table 5-21 and PJM Interconnection, L.L.C., "2022/2023 RPM Base Residual Auction Results," June 2, 2021, Table 4, p. 15. See list of acronyms for full LDA names.