Carbon Abatement Value of Existing Clean Generators

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NOTICE

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Executive Summary

Meeting the unprecedented surge in US electricity demand while simultaneously fulfilling clean energy commitments will require both the addition of new clean energy resources and the continued operation of existing ones. Up to now, clean energy and climate policies, as well as private-sector voluntary commitments, have mostly prioritized the development of new resources. That is understandable given the scale of new clean generation needed to achieve meaningful greenhouse gas (GHG) emissions reductions, and the value of early market formation policies that are critical for bringing down the costs of renewable energy technologies.

However, it is also crucial to retain existing clean generation resources such as nuclear and hydropower plants, which still produce a combined 61% of the total clean generation in the US. Since 2012, 13 nuclear units have retired prematurely, many for purely economic reasons. Each year, the lost output from these shutdown units offsets about 13% of the clean power generated by the current fleet of US wind, solar, and biomass resources. Pursuing new clean energy development while allowing existing clean resources to retire is akin to filling a bathtub with the drain open – feasible in principle with sufficiently high inflow, but unnecessarily challenging and less effective. Looking forward, any further preventable loss of existing clean energy resources will increase the challenge for states and companies to achieve their clean energy and decarbonization goals.

In this report, we evaluate the role of existing clean resources in decarbonization strategies and examine how policy frameworks may need to evolve to achieve a reliable and affordable clean energy future. We find that:

- **Existing clean energy resources prevent significant GHG emissions today**. Losing a clean power resource will increase emissions; its lost output will be replaced largely by fossil generation in the near term, gas-fired in most markets. For example, we estimate that the annual GHG emissions avoided by a 1,000-MW nuclear power plant in PJM is 4.2–6.5 million metric tons of CO_2 (tCO_2), equivalent to the annual emissions of approximately 900,000–1.4 million passenger vehicles. These emissions benefits will extend for many years into the future, with their magnitude diminishing somewhat as the grid becomes cleaner over time. Most jurisdictions and markets do not explicitly recognize the emissions benefits of these resources.
- **In addition to their clean energy output, existing clean resources provide significant system resource adequacy benefits.** While, in principle, the clean energy output of a 1,000 MW nuclear plant could be replaced by about 3,600 MW of renewable generation (a mix of

solar and wind), these renewables would not replace the nuclear plant's full contribution to system resource adequacy. Supplemental dispatchable generation such as battery storage or thermal plants, or even greater amounts of renewable capacity, would be needed on top of the 3,600 MW of replacement renewables to achieve the same level of resource adequacy. The need for nuclear's resource adequacy contribution will only increase in the future, as renewable deployment increases, fossil resources retire, and load growth quickens.

- **Real-world constraints make it challenging in the current environment to replace retiring clean energy resources.** The growing backlog of projects awaiting interconnection, long lead times for new transmission infrastructure, supply-chain challenges and increased costs are delaying the integration of new clean energy resources into the power system. Meanwhile, the industry is expecting high overall demand growth, prompting a surge in new gas-fired generation and even delaying scheduled coal plant retirements. Taken together, these developments indicate that a retiring clean energy resource is unlikely to be fully replaced by incremental new clean energy resources in the near term.
- **The economic viability and continued clean energy contributions of merchant nuclear plants can depend on whether and how they are compensated for their clean attributes.** Some nuclear (and most hydro) generators are still rate-regulated and thus not acutely exposed to the near-term economic pressures of competitive power markets. Merchant nuclear plants, or those that generate and sell electricity in organized energy markets, would be most exposed because, unlike rate-regulated nuclear plants, they must cover their entire operating costs and risks from the energy and capacity revenues available in power markets, plus any compensation they may receive for their clean energy attributes.
- **Federal and state governments have established support programs that recognize the emissions benefits of clean energy resources.** Policy tools – such as the federal Production Tax Credit (PTC) and Investment Tax Credit (ITC), and state-level Renewable Portfolio Standard (RPS) – have been deployed to support new renewable and clean generators. Similarly, private-sector clean energy commitments have largely focused on procuring new resources. More recently, recognizing some of the economic challenges faced by existing clean generators, federal and state governments have provided support for existing clean energy resources through mechanisms such as state Zero-Emissions Credit (ZEC) programs and the federal 45U PTC for existing nuclear power facilities.
- **However, these programs are time-limited, and their expiration will leave existing clean generators, particularly merchant nuclear, economically vulnerable.** We show that representative nuclear plants in PJM are likely to experience severe economic challenges in the mid-2030s if existing support programs are discontinued, with negative estimated

operating margins. A sharp decline in economic viability for many merchant nuclear plants is anticipated in 2033 following the scheduled expiration of the federal PTC. Complicating the situation, increasing renewable deployment – encouraged by policies supporting new renewables – will suppress energy market prices, further undermining the economic viability of existing nuclear generators.

As power systems across the country continue to add new clean energy resources, driven by economics, state policies, and corporate clean energy commitments, a holistic and enduring framework is needed to recognize the emissions benefits of all clean energy resources, including existing ones. This framework should guide policy development and voluntary procurement to support efficient and durable decarbonization outcomes.

In the public policy arena, several proposals have advanced this concept by exploring market-based mechanisms that explicitly value the clean characteristics that different resources can offer, regardless of their vintage. For states with existing clean energy standards, zero-emitting resources are generally all treated equally. Another example that is being considered in several regions is the concept of a clean capacity product or certificate.

The framework for voluntary procurement should evolve. Rather than limiting eligibility to new generating resources, which could leave existing resources economically vulnerable, the focus should be on whether demand for carbon-free electricity (CFE) would lead to increased CFE supply. For example, we find that in PJM, which has a large concentration of existing clean nuclear resources, the overall demand for CFE will likely outstrip available CFE supply, including that from existing resources, by the early 2030s. Once overall demand surpasses supply, any incremental new CFE demand will incentivize new CFE development. In that sense, the distinction between new and existing resources becomes less meaningful, alleviating concerns that allowing existing resources to qualify for voluntary procurement might flood the CFE market and dampen demand for new resources.

As market conditions shift and as states and companies progress toward their clean energy goals, it is essential to establish a unified emissions accounting and clean energy procurement framework that recognizes and values the contributions of all clean energy resources. Such a framework can serve as the foundation for developing efficient and effective decarbonization policy and guidance – paving the way for a reliable, affordable, and fully decarbonized electricity system.

I. Introduction

Meeting the unprecedented surge in electricity demand in the US while upholding clean energy commitments will require substantial investments to expand new clean energy sources, as well as maintaining the significant quantities of clean resources that are already operating. After years of stagnant electricity sales and load growth, electricity demand is rising at its fastest rate in the last two decades.[1] This shift is driven by emerging and expanding energy-intensive sectors, including data centers, manufacturing – spurred by onshoring and industrial policy – and the electrification of the transportation and building sectors.

Much attention has been devoted to deploying new clean generation and storage technologies, grid enhancement technologies, and demand-side technologies to meet this new demand surge with clean energy resources, as well as expand clean energy more generally. However, existing clean energy generation has received relatively less attention, despite the important role it plays in decarbonizing the power system.[2]

Existing nuclear and hydropower facilities have been providing energy to the power system for decades, contributing meaningfully to the country's total clean energy resources since well before most clean energy policies were enacted. According to the US Energy Information Administration (EIA), in 2023, nuclear and hydropower together made up almost a quarter of total US electricity generation (19% and 6%, respectively), compared to a total of about 16% for all non-hydro renewable resources (wind, solar, biomass, and geothermal).[3] However, in energy policy discussions, it is often simply assumed that these existing clean energy resources will remain available in the future.

Pursuing greenhouse gas (GHG) emissions reduction goals solely by encouraging new clean resources implicitly assumes that all existing clean resources will continue to provide clean energy. This assumption is not always valid, as evidenced by instances where existing clean

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1 T. Bruce Tsuchida, Long Lam, et al., *Electricity Demand Growth and Forecasting in a Time of Change*, The Brattle Group (May 2024), https://www.brattle.com/wp-content/uploads/2024/05/Electricity-Demand-Growth-and-Forecasting-in-a-Time-of-Change-1.pdf.

2 US Department of Energy, *The Future of Resource Adequacy: Solutions for clean, reliable, secure, and affordable electricity* (April 2024), https://www.energy.gov/sites/default/files/2024-04/2024%20The%20Future%20of%20Resource%20Adequacy%20Report.pdf.

3 Nuclear and hydropower together comprised 61% of total renewable generation in the US in 2023. US Energy Information Administration, "Frequently Asked Questions (FAQs): What is US electricity generation by energy source?" https://www.eia.gov/tools/faqs/faq.php?id=427&t=3.

resources have retired prematurely due to poor economics. For example, 13 nuclear reactors with a total generating capacity of about 10.2 GW have been retired or mothballed since 2012.[4] While the reasons behind the retirements have varied depending on each plant's economic, engineering, and regulatory context, the drivers have often included sustained low wholesale power prices that challenge the plants' economics, given that they have not generally been compensated for their clean power attributes.[5] These economic challenges have sometimes been accompanied by engineering problems or a need for significant investment in repairs or upgrades.[6] When market structures do not recognize a plant's clean attributes, factors like these can threaten its economic viability.

US energy policy and corporate procurement strategies have historically focused on supporting new clean energy generation in pursuit of decarbonization goals. An array of economic and regulatory policy incentives are available for new clean energy resources at the federal and state levels, including Production Tax Credits (PTCs), Investment Tax Credits (ITCs), and Renewable Portfolio Standard (RPS) requirements.[7] In addition, many corporate buyers choose to procure new clean energy resources to meet their clean energy commitments, based on a common but not always correct assumption that adding new clean resources will increase the overall quantity of clean generation and decrease emitting generation. This focus on new resources is understandable, as significantly more clean energy resources will be needed. However, doing so without consideration for existing clean resources can threaten their foundational role in maintaining the clean energy production that already exists.

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4 Congressional Research Services, *US Nuclear Plant Shutdowns, State Interventions, and Policy Concerns* (February 7, 2022). This report was published prior to the retirement of the Palisades nuclear plant and does not include it in the list of retirements. 10.2 GW of generating capacity is calculated as the sum of the generating capacities reported in Table 1 of the study plus the generating capacity of the Palisades nuclear plant, which is reported in Table 2 of the study. We note that Palisades and Three Mile Island (Crane) are scheduled to restart. *See* Larry Pearl, "Holtec International formally launches process to restart Palisades nuclear power plant," *Utility Dive* (September 13, 2023); C. Mandler, "Three Mile Island nuclear plant will reopen to power Microsoft data centers," *NPR* (September 20, 2024).

5 Low wholesale electricity prices have been driven primarily by low natural gas prices, since gas is often the price-setting electricity fuel in many markets; the growing deployment of zero-marginal cost generation, such as wind and solar, has also played some role.

6 While economic pressure on nuclear plants under rate regulation is less immediate than for merchant plants, since the revenues of a rate-regulated plant are determined by state regulators rather than markets, economic and engineering challenges may still threaten their economic viability.

7 For a summary of federal programs to encourage renewable energy, please refer to Congressional Research Service, Renewable Energy and Energy Efficiency Incentives: A Summary of Federal Programs (February 10, 2023). For a comprehensive database of state incentives, please see DSIRE|NC Clean Energy Technology Center, Database of State Incentives for Renewables & Efficiency® at https://www.dsireusa.org/.

In more recent years, the federal and state governments have stepped in to provide support for existing clean resources. Several states, including New York, New Jersey, and Illinois, have established programs such as the Zero-Emissions Credit (ZEC) program and the Carbon Mitigation Credit (CMC) program, which acknowledge the emissions abatement value of existing nuclear generation and provide some compensation for it.[8] In the Inflation Reduction Act (IRA), Congress decided to remove the burden from states, providing a federal PTC for zero-emission power produced at qualified nuclear power facilities under Section 45U of the Internal Revenue Code.[9]

However, beginning with the discontinuation of the New Jersey ZEC Program in May of this year, these programs are scheduled to expire in the coming years, and broader questions will remain about the long-term strategy for sustaining clean energy production from existing resources.[10] As power systems around the country continue to add new clean energy resources, driven largely by economics, state policies, and corporate clean energy goals, it is important to ensure that there are mechanisms to recognize the environmental attributes and value of existing clean resources. Keeping these existing resources operating will ensure that adding new resources does in fact lead to greater clean energy production and reduced emissions.

To address these questions, we examine the emissions consequences of retiring clean energy resources from historical and forward-looking perspectives (Section II), and resource adequacy implications accounting for how the power system will evolve in future years (Section III). We then examine the importance of developing a permanent mechanism to recognize the emissions benefits of nuclear power plants. The absence of such a mechanism would pose a risk to the long-term economic viability of many nuclear facilities (Section IV). Next, we explore how voluntary procurement of carbon-free electricity (CFE) programs can serve as a long-term mechanism to recognize emissions benefits, and how an "additionality" requirement may be less meaningful in markets where total CFE demand exceeds total supply (Section V).[11] Finally, we discuss the broader policy implications of these findings for the future of clean energy (Section VI).

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8 Illinois Power Agency, *Zero Emission Standard Procurement Plan* (July 31, 2017); Illinois Power Agency, *Carbon Mitigation Credit Procurement Plan* (December 13, 2021); New Jersey Board of Public Utilities, *N.J. Stat. § 48:3-87.5* (May 23, 2018); State of New York Public Service Commission, *Order Adopting a Clean Energy Standard, Case 15-E-0302* (August 1, 2016).

9 IRS, "Zero-Emission Nuclear Power Production Credit," https://www.irs.gov/credits-deductions/zero-emission-nuclear-power-production-credit.

10 The 45U PTC is available through 2032. The current IL ZEC and CMC procurement programs are in place through May 2027. In New Jersey, nuclear plant owners intend to take advantage of the 45U PTC and did not participate in the June 2025 through May 2028 procurement round; the state subsequently closed the program.

11 Additionality is sometimes used as a shorthand for "new." In this paper, we consider a resource to be additional if it would not have existed without some intervention. Under this definition, a resource at risk of economic shutdown (or restarting after being shut down) is considered additional.

II. Emissions Impacts of Retiring Existing Clean Resources

Both existing and new clean energy resources will be necessary to meet deep GHG emissions reduction targets. Developing new resources while allowing existing resources to retire is akin to filling a bathtub with the drain open – perhaps it is possible with a sufficiently high inflow rate, but it is unlikely to be an effective or efficient approach. For instance, in New England, carbon emissions had been steadily declining before the Vermont Yankee Nuclear Power Plant shutdown, but increased in the year after its closure, as its clean generation was replaced primarily with gas-fired power.[12]

Similarly, a recent study highlights Diablo Canyon Power Plant's key role in helping California meet its emissions reduction targets, finding that retaining Diablo Canyon would displace in-state gas-fired generation and imports of higher-emitting electricity.[13] Premature closures of existing clean generators will undermine efforts to reduce emissions from the power sector and other sectors that will rely on electrification and grid decarbonization to reduce emissions. Such closures can increase overall electricity costs and delay decarbonization.

To understand the potential GHG emissions impact of shutting down an existing nuclear plant, it is important to characterize three different metrics:

- **Emissions impact based on replacement resource:** Determine the emissions impact using the carbon intensity of a fossil fuel generator as the substitute. For example, in PJM, the likely substitute generation would be an average of a coal power plant and a combined-cycle gas power plant.
- **Emissions impact based on the marginal emissions rate:** Determine the emissions impact using the carbon intensity that corresponds with the marginal generator throughout the year. This approach accounts for the structure of the supply curve of power plants, as well as the distribution of emissions rates among power plants. The removal of supply from within the

[12] MIT, *The Future of Nuclear Energy in a Carbon-Constrained World: An Interdisciplinary MIT Study*, Revision 1 (2018), p. 96, https://energy.mit.edu/wp-content/uploads/2018/09/The-Future-of-Nuclear-Energy-in-a-Carbon-Constrained-World.pdf.

[13] Samuel Newell, et al., *Retaining Diablo Canyon: Economic, Carbon, and Reliability Implications,* The Brattle Group, prepared for Policy Impact on Behalf of Carbon Free California (June 9, 2022), https://www.brattle.com/wp-content/uploads/2022/06/Retaining-Diablo-Canyon-Economic-Carbon-and-Reliability-Implications.pdf.

supply curve would impact the positioning (and corresponding emissions rate) of the market equilibrium. In PJM, the marginal emissions rate was, on average, 0.53 tCO_2 per MWh in 2023.[14]

- **Emissions impact based on the system average non-baseload emissions rate:** Determine the emissions impact using the carbon intensity corresponding to the average fossil fuel emissions rate weighted by the probability that the unit is marginal. These probabilities are proxied by eGRID using a unit's capacity factor, where a lower capacity factor signifies a higher probability of being marginal. This represents a conservative estimate for marginal emissions rates, where the removal of supply is likely to primarily induce marginal fossil fuel generation.

TABLE 1: ESTIMATED EMISSIONS RATES AND IMPACTS OF RETIRING A NUCLEAR PLANT

Metric	CO_2 Emissions Rate (tCO_2/MWh)	Description	Impacts of Retiring a 1,000 MW Nuclear Plant ($MMTCO_2$)[1]
Emissions Impact Based on Replacement Resource	0.51	The emissions rate of the replacement resource is calculated as the volume-weighted average emissions rates of the PJM gas/coal fleet	4.2
Emissions Impact Based on the Marginal Emissions Rate	0.53	The substitute emissions rate is based on marginal CO_2 emissions rates for the PJM region[3]	4.3
Emissions Impact Based on the System Average Non-Baseload Emissions Rate	0.53 (RFC East) 0.80 (RFC West)[2]	The substitute emissions rate is based on average non-baseload (fuel-combusting) CO_2 emissions rates from 2022 eGRID for the PJM region[4]	4.32 (RFC East) 6.45 (RFC West)

Notes and sources: (1) Assumes the nuclear plant has a 92% summer capacity factor and constant generation profile; MMT: million metric tons; (2) RFC East and West refer to regions of the Reliability First Corporation reliability organization, as denoted by the EPA for its eGRID model (*see* EPA, Emissions & Generation Resource Integrated Database (eGRID) (2025)); (3) PJM DataMiner 2 for PJM-RTO; (4) Calculated by EIA using average emissions rate of thermal plants inversely weighted by their capacity factor, for all plants with capacity factors less than 0.8 (*see* EPA, Emissions & Generation Resource Integrated Database (eGRID) (2025)).

Table 1 shows the estimated emissions impacts of retiring a 1,000-MW nuclear power plant in PJM. Each MWh of electricity generated from the nuclear power plant avoids 0.51–0.80 metric tons of CO_2 (tCO_2). Operating with a 92% summer capacity factor, the nuclear plant would avoid

[14] The average and marginal emissions rates both reflect the emissions impact, but are often used to serve different purposes. Average emissions rates are calculated by dividing the total system emissions by the total generation, which is a useful metric for emissions inventory accounting. Marginal emissions rates reflect how external forces that affect the demand for electricity can cause incremental changes in emissions, which can inform operational decisions. See PJM, *Marginal Emissions Rate—A Primer* (accessed March 24, 2025).

4.2–6.5 million tCO_2 in one year, the equivalent emissions of approximately 913,000–1.4 million gasoline-powered cars per year.[15]

Replacing a retiring low-carbon resource with another low-carbon resource can mitigate the emissions increase, but doing so in a high load growth environment can be challenging. Progress in integrating new clean energy resources into the power system has been slow; renewable resources are not being connected at a pace that can meet the increasing demand for clean power. The process of interconnecting renewable resources is getting longer, largely because of the high number of projects awaiting interconnection, and because it is challenging to build out new transmission infrastructure that is needed to deliver power. For example, in PJM, over 3,000 projects totaling about 300 GW in capacity were in the interconnection queue as of 2023, the overwhelming majority of which consist of wind and solar projects.[16] For projects completed in 2022–2023, the median time from filing an interconnection request to commercial operation approaches five years. Under this timeline, new proposed projects entering the queue today would not be operational until 2030.

Exacerbating this, current US demand for electricity is at record highs, with projections published by the North American Electric Reliability Corporation (NERC) estimating an increase of over 122 GW in the next decade – the fastest growth rate seen in several decades. Many US regions are not adding enough supply, regardless of whether the new supply is clean, leading to concerns about resource adequacy over the next decade.[17] As one mitigation measure, utilities have extended the life of about a third of coal plants that were previously slated for retirement, either by delaying their closure or by canceling retirements altogether.[18]

While Table 1 offers a static snapshot of the annual emissions impacts of retiring a nuclear plant today, it does not capture how these impacts will evolve over the next decades amid the many changes in the power system. To better understand the system emissions impacts of retiring a nuclear plant as the power system evolves over the next decades, we use gridSIM, Brattle's proprietary power system simulation model. This model characterizes the power system and

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15 Assuming each car emits 4.6 tCO_2 annually. See US EPA, "Greenhouse Gas Emissions from a Typical Passenger Vehicle."

16 Lawrence Berkeley National Laboratory, *Queued Up: 2024 Edition Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023* (April 2024), https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf.

17 Statement of the North American Electric Reliability Corporation 2024 Reliability Technical Conference, Docket No. AD24-10-000 (October 16, 2024), https://www.nerc.com/news/Headlines%20DL/NERC%202024%20RTC%20Statement%20FINAL.pdf.

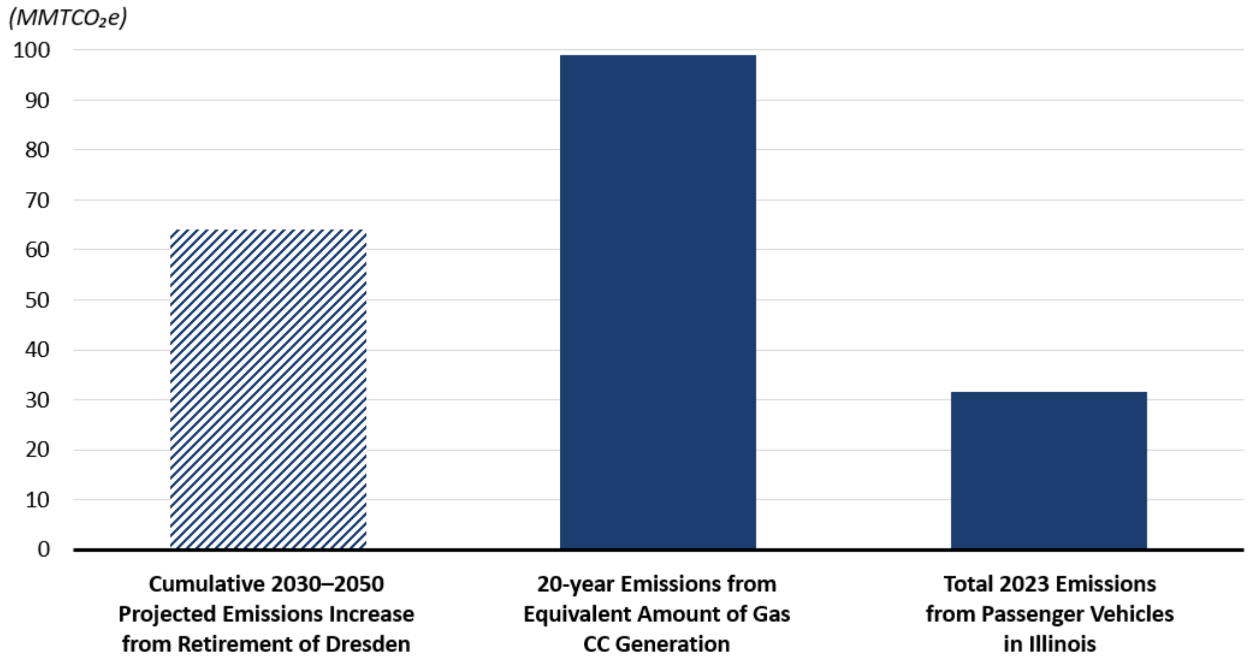
18 Austin Gaffney and Mira Rojanasakul, "Where Coal is Retiring, and Hanging On, In the US," *The New York Times*, (February 6, 2025), https://www.nytimes.com/interactive/2025/02/06/climate/coal-plants-retirement.html.

simulates both short-term hourly operations and long-term capacity changes, including additions and retirements. The simulation captures the evolving dynamics of plant operations and power markets. The model covers the entire MISO and PJM power systems, accounting for power interchange between these regions and neighboring systems. Using this modeling approach, we can assess the impacts of retiring a zero-emissions generator on the generating capacity mix (through retirements and new developments), power system operations, and overall system emissions. For an overview of the gridSIM model and further details on modeling assumptions, please refer to Appendix B.

In this analysis, we analyze the emissions impacts of retiring the 1,845 MW Dresden Generating Station nuclear plant located in PJM between 2030 and 2050. Our analysis involves two scenarios. In the first, the nuclear plant obtains a 20-year extension and remains fully operational until the end of 2049 and partially operational until the start of 2051, when its two units respectively retire (Scenario 1). In the second, one of the two units is retired at the end of 2029, and the other at the start of 2031 (Scenario 2). By holding the other variables constant and comparing the emissions results of the two model runs, we can quantify the emissions value of the nuclear plant.

As shown in Figure 1 below, retiring the nuclear plant would lead to higher GHG emissions in PJM. This outcome reflects the reliance on fossil-fueled generation to replace most of the plant's output. Between 2030 and 2050, cumulative emissions in Scenario 2 exceed those in Scenario 1 by about 64 million metric tons (MMT) of CO_2 – an average of 3.2 $MMTCO_2$ per year over the 20-year period. To put the emissions increase in context, two other values are plotted: the 20-year emissions of an equivalent amount of generation from a conventional gas combined cycle plant ("gas CC"), and the total estimated annual emissions from passenger vehicles in Illinois. The emissions increase is most pronounced in the early years, when gas-fired generation accounts for most of the replacement capacity. Over time, more renewable energy and storage resources are added to the power system to meet more stringent emissions goals, contributing to lower total system emissions.

FIGURE 1: CUMULATIVE EMISSIONS INCREASE FROM RETIREMENT OF DRESDEN IN PERSPECTIVE



Notes: Emissions were calculated using an assumed CC heat rate of approximately 6,400 MMBtu/MWh, consistent with a new gas CC unit in PJM. Emissions from passenger vehicles were calculated using EPA data for average emissions per passenger vehicle, and ilsos.gov data on vehicle count. See Greenhouse Gas Emissions from a Typical Passenger Vehicle | US EPA and COUNTY.CSV.

III. Resource Adequacy Value of Existing Clean Resources

Nuclear plants deliver consistent, predictable output regardless of time of day and weather conditions. Their retirement can pose emissions challenges if replaced with gas generation, as discussed above, and can also affect resource adequacy if replaced only with intermittent non-emitting generation, such as new wind or solar resources. This can be seen through PJM's current Effective Load Carrying Capability (ELCC) framework, which evaluates a resource's contribution to adequacy based on its ability to provide power when the system needs it, in the context of the timing of load and power from other generators. Under the ELCC framework, nuclear capacity is more valuable than intermittent renewable capacity from a resource adequacy perspective. In the 2025/2026 Base Residual Auction (BRA), one nameplate MW of nuclear has an ELCC value of 95%, versus 35% for onshore wind and 9% for fixed-tilt solar.[19]

Currently, the lower ELCC values for wind and solar are largely driven by these resources' lower capacity factors. As more renewable resources are deployed, their ELCC values will decline for an additional reason: the output of a wind generator tends to be highly correlated with the output of other wind generators, and similarly for solar. As the amount of wind capacity increases, adding still more new wind capacity will provide more energy, mostly in hours when the system has sufficient energy (because of the existing wind generation in those hours), and again similarly for solar. The ELCCs of these resource types (i.e., their marginal contribution to system resource needs) will decline further, as the system's remaining resource adequacy needs are concentrated in the hours when the renewables generate little.[20]

Because nuclear power is produced at all hours and is generally unaffected by weather conditions, its resource adequacy contribution does not diminish in the same way. So, as the system progresses to a largely decarbonized, high-renewable future, nuclear generation will provide increasingly greater resource adequacy value, relative to intermittent renewables alone. For instance, PJM's preliminary ELCC ratings show that by 2031/2032, the ELCC for onshore wind will fall to 21% (vs. 35%), and to 4% (vs 9%) for fixed-tilt solar, while the ELCC for nuclear will be nearly

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[19] PJM, *ELCC Class Ratings for the 2025/2026 Base Residual Auction*, https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2025-2026-bra-elcc-class-ratings.pdf.

[20] Samuel A. Newell, et al., *Capacity Resource Accreditation for New England's Clean Energy Transition—Report 1: Foundations of Resource Accreditation* (June 2, 2022), https://www.brattle.com/wp-content/uploads/2022/06/Capacity-Resource-Accreditation-for-New-Englands-Clean-Energy-Transition-Foundations-of-Resource-Accreditation-1.pdf.

unchanged at 93%.[21] This growing discrepancy in resource adequacy contribution will only increase as renewable energy deployment increases further. Pairing storage with renewables can improve their ELCC values, though it also increases cost, and still would not match the value of nuclear. Thus, while it is reasonably straightforward in principle to replace a lost nuclear unit's clean energy with a comparable amount of clean renewable energy, the resource adequacy value of the renewable replacement will be substantially less than that of the nuclear generator.

To illustrate this point, we assessed the replacement resource mix that would be needed to achieve the same resource adequacy value as a hypothetical 1,000 MW nuclear plant retiring in PJM. While declining ELCCs impact the reliability effects of replacing existing nuclear with new renewable resources anywhere, they are particularly salient in a market like PJM, where nuclear makes up a considerable share of generating capacity, and where targets for future renewable deployment are ambitious.

Replacing a 1,000 MW nuclear plant with enough intermittent renewable capacity to match its lost clean generation on an annual basis would require around 3,600 MW of new renewable capacity (assuming the current two-to-one ratio of wind and solar in PJM). Using the ELCC class ratings from the 2025/2026 BRA, these 3,600 MW of renewable capacity represent almost 950 MW of resource adequacy value, virtually the same as the lost resource adequacy value of the retiring nuclear plant. However, if this is estimated using the projected ELCC class ratings for the 2031/2032 resource class, these same renewable resources represent just 550 MW of capacity value, about 40% less than the lost nuclear plant.[22]

This suggests that six years from now, retiring a 1,000 MW nuclear plant would not only require 3,600 MW of renewable capacity to replace its lost clean energy, but also additional capacity to make up for the reduced resource adequacy value of the renewables. A further 400 MW of perfectly reliable generating capacity (which could be provided by another 2,600 MW of renewables, 460 MW of combined cycle gas, or 950 MW of 4hr battery storage) would be required to supplement the lost resource adequacy value. In the still longer term, increasing penetration of intermittent renewable resources and their declining ELCC values reflect an increasing need for supplemental firm generation resources over time. The resource adequacy

[21] PJM, *Preliminary ELCC Class Ratings for period Delivery Year 2026/27—Delivery Year 2034/35*, https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.pdf.

[22] The precise impact depends on the ratio of wind to solar capacity assumed. This estimate uses PJM's current installed wind-to-solar ratio of approximately 2:1. However, the vast majority of capacity in PJM's interconnection queue now is solar; if the installed balance shifts towards solar by 2031, replacing lost nuclear generation with an equal amount of renewable generation will result in an even greater loss in resource adequacy value.

value of existing nuclear resources, if they continue to operate, will stay robust to meet this demand.

IV. Future Economic Viability of Nuclear Power Plants

Policymakers have implemented mechanisms such as state ZEC programs and the federal 45U PTC, which recognize the emissions-free characteristics and reliability benefits of nuclear power plants. The intent of these policy measures is generally to ensure their continued economic viability, but these measures are scheduled to eventually expire. Without replacement measures to recognize and provide compensation for their low-carbon attributes, the long-term economic viability of existing nuclear facilities may be threatened. A framework that recognizes the emissions-free attributes of all clean energy resources across both public policy and voluntary procurement programs will be essential to enabling efficient and durable progress toward decarbonization.

To explore the importance of developing such a framework, we evaluate how the long-term economics of a representative nuclear plant in PJM will change following the 2032 expiry of the 45U credits. We consider total revenue minus total avoidable cost (consisting of fixed and variable operating and maintenance costs, plus ongoing capital expense requirements). In general, three revenue streams are currently available to nuclear plants in PJM – energy and capacity revenues, and tax credits. For this analysis, we use energy and capacity price estimates from the National Renewable Energy Laboratory's (NREL) 2023 Cambium model,[23] and the 45U production tax credit:

- **Energy revenue**: This analysis uses the average annual energy prices from Cambium for different balancing areas within PJM. A weighted average price for PJM is calculated using the size and locations of operational PJM nuclear plants, assuming a constant baseload generation profile.
- **Capacity revenue**: Each nuclear plant participating in PJM's Base Residual Auction receives payments for providing its capacity to the market. Again, this analysis uses a weighted average Cambium price based on the size and locations of operational PJM nuclear plants.
- **Production tax credit**: The 45U tax credit is designed to provide electricity generation from existing nuclear power facilities with up to $15 for each MWh generated. The tax credit

[23] NREL, Cambium 2023 (February 2024)

depends on meeting prevailing wage requirements and is formulaically tied to a plant's gross receipts, with adjustments for inflation.[24] It is available through 2032.

The Cambium 2023 "Mid-Case" is based on central estimates for inputs and yields mid-range estimates of energy and capacity prices for the balancing areas within PJM. We also consider other Cambium cases, including:

- Low and high renewable energy costs ("Low RE Cost" and "High RE Cost");
- High demand growth ("High Demand Growth"); and
- Low and high natural gas prices ("Low NG Price" and "High NG Price").[25]

There is substantial variability in avoidable costs across the nuclear fleet; costs may be influenced by plant size and age, as well as idiosyncratic factors at each plant. Unit-specific nuclear plant costs are confidential and reliable information is not publicly available, so for this analysis we use a hypothetical estimate for avoidable costs derived from the 45U gross receipts formula – the gross revenue threshold above which the 45U PTC goes to zero. This threshold can be thought of as a proxy for a representative plant's avoidable costs, consistent with the intent of the tax credit. If a plant's avoidable costs were exactly equal to this gross revenue threshold, it would break even economically; at higher gross revenue, it would be at least marginally profitable and no PTC payment would be needed to ensure the plant's continued viability. The threshold in the 45U gross receipts formula is adjusted for inflation; for 2023, it was equal to $43.75/MWh (see Appendix C for additional detail on the cost methodology).[26]

The purpose of this analysis is not to establish the profitability of any particular nuclear plant, but to illustrate how net revenues for nuclear plants will fall with the expiry of the PTC. It also highlights that without the PTC, many nuclear plants may be economically threatened, even

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24 The PTC Payment is calculated using the following formula: 5 × [$3 × (Eligible MWh Sales) − 16% × (Gross Receipts − $25 × Eligible MWh Sales)], with a maximum of $15/MWh. (Please refer to the appendix for more details.) However, the Internal Revenue Service has not issued guidance to clarify what "gross receipts" should include. For this analysis, we assume that gross receipts include revenues from energy and capacity payments.

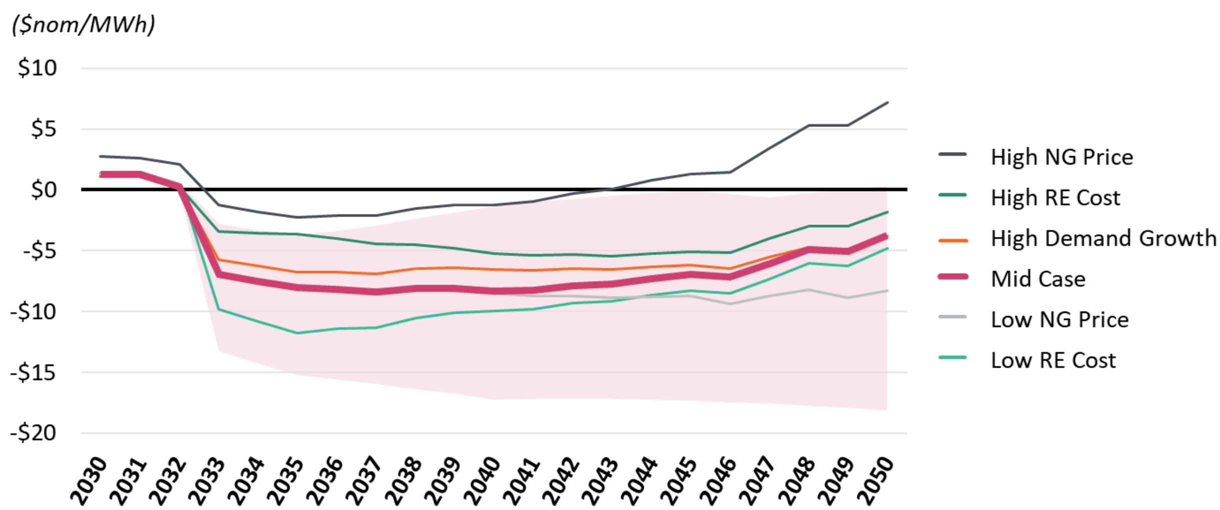
25 The Cambium analyses also consider two deep decarbonization scenarios – "100% Decarbonization by 2035" and "95% Decarbonization by 2050" – that are not evaluated here. These scenarios are qualitatively different from the other six; both implement a national electricity sector CO_2 constraint and rely on nascent technologies to achieve it. Under these deep decarbonization scenarios, nuclear plants would have considerably higher net revenues, due to higher capacity and energy prices (though not until 2040 for the 95% Decarbonization by 2050 case).

26 The gross receipts method is formulaically designed such that the PTC declines as gross revenue increases until the total revenue, including the PTC, exceeds a target threshold. In 2023, the target threshold was $43.75/MWh. The approach of using this as a measure of costs is based on the assumption that a nuclear facility with equivalent costs would be "made whole" with the PTC, unless market revenues decline to extremely low levels.

across a broad range of plausible price trajectories, absent some alternative form of compensation for the emissions-free attributes of their output.

Figure 2 below shows the representative net revenues for nuclear plants in PJM, illustrating that these representative plants would experience a sharp economic downturn in 2033 following the expiry of the 45U PTC. The bold pink line illustrates the weighted average of the PJM zones for the Cambium Mid-Case prices (different zones have different prices); the pink shaded region shows the range across these zones for the Mid-Case.[27] With the 45U PTC (up through 2032), a representative nuclear plant is marginally profitable, but following the PTC expiry, its profitability drops markedly. Very similar results occur for the other Cambium price cases; their weighted averages are illustrated by the thinner lines in Figure 2. Under even the higher-price Cambium cases, such as High NG Price or High RE Cost, in many PJM balancing areas, a nuclear plant with representative costs would operate at a loss immediately following the PTC's expiration.

FIGURE 2: NET REVENUES FOR PJM NUCLEAR FLEET ACROSS SIX ENERGY PRICE SCENARIOS



Source and Notes: Brattle analysis. The pink line represents the generation-weighted average across the PJM nuclear fleet under the Cambium 2023 Mid-Case, and the pink band represents the range across all balancing areas in the Mid-Case. Other lines represent the averages for other Cambium cases. This analysis does not reflect idiosyncratic costs and regulatory risks that an individual unit may face.

This analysis uses representative nuclear avoidable costs, based on the PTC gross revenue threshold, to estimate net revenues. Of course, plants with higher costs may be even less profitable than the representative plant analyzed. As nuclear units age, operations and maintenance (O&M) costs and the ongoing capital investments required to ensure safe and

[27] This range is defined by differing zonal prices, with weighting based on the nuclear generation in each zone. For all assuming the same plant costs (based on the 45U threshold as described above). The actual range would likely be wider if variability in nuclear plant costs were accounted for.

reliable operation tend to increase and may become more uncertain.[28] Components wear and require replacement or upgrades to ensure compatibility with newer equipment standards; older units may also require more frequent inspections and more stringent monitoring to comply with regulatory requirements, which may themselves change over time. Smaller plants also tend to have higher costs, relative to their output, and are often older as well. This suggests that many plants may be unlikely to survive the expiry of the 45U PTC, absent some alternative mechanism to compensate them for their emission-free attributes.[29]

[28] Sargent & Lundy, *IPM Model – Nuclear Power Plant Costs* (January 2018).

[29] These findings are robust across a variety of power sector and capacity expansion models outside of the NREL Cambium model. We examined projected net revenues using energy and capacity price results from EPA's IPM model as well as our in-house gridSIM capacity expansion model and found that the loss of the PTC in 2032 posed major economic challenges across all models.

V. Projected Available CFE Supply/Demand Balance in PJM

Beyond energy and capacity revenues and applicable production tax credits, clean energy resources can also receive payments for selling their Renewable Energy Certificates (RECs) or Energy Attribute Certificates (EACs) on the compliance or voluntary markets.[30] In compliance REC markets, utilities and electricity suppliers procure RECs to meet state-mandated Renewable Portfolio Standards (RPS), which require that a specific percentage of the state's electricity sales or supply come from renewable sources. The purchased RECs are then retired. Separately, to meet their preferences and commitments, private individuals and organizations can pursue voluntary procurement of clean energy via power purchase agreements, green utility programs, and direct purchase of clean energy instruments (i.e., RECs or EACs).

Debates over the definition of a "high-quality" clean energy instrument have attracted considerable interest in recent years. These discussions gained broader attention in 2023, when the US Department of the Treasury was finalizing regulations for the 45V tax credit, a key incentive for hydrogen development. Around the same time, the Greenhouse Gas Protocol (GHGP) initiated a multi-year process to revisit its Scope 2 Guidance, which describes how private companies should tabulate and report their emissions associated with power consumption. As part of this process, the GHGP is considering the criteria necessary for impactful clean energy procurement.[31] The Science Based Targets initiative (SBTi), an organization that provides standards and guidance for companies to set their GHG emissions reduction targets aligned with the latest climate science, is undergoing a similar process.

In these settings, some stakeholders have proposed an approach where the procured energy must be (1) additional (sometimes referred to as incremental), (2) deliverable, and (3) matched to load on an hourly basis. However, interpreting the additionality requirement to mean only "new" resources would exclude a large group of existing clean energy resources from meeting demand for clean energy, potentially threatening their long-term economic viability.

[30] In general, EACs refer to a broad category of certificates that verify the generation of electricity from clean or low-carbon resources. RECs refer to a specific type of EAC, primarily used in the US compliance markets (e.g., for meeting Renewable Portfolio Standards) and sometimes also in voluntary clean energy procurement programs. Each REC represents proof that one megawatt-hour (MWh) of electricity was generated from an eligible renewable energy resource. In this report, we use the terms EAC and REC interchangeably.

[31] For example, see Michael Macrae and Kyla Aiuto, *GHG Protocol Standards Update Process: Topline Findings From Scope 2 Feedback*, Greenhouse Gas Protocol (May 2, 2023).

Experience shows that existing resources can actually be additional (incremental) if their viability is threatened (as in the case of economic retirements of nuclear plants). In fact, the converse interpretation – that new resources are by definition additional – can also be problematic in some instances. In certain regions with very good renewable resources, new clean assets would be developed because it is economic to do so even without compensation for their clean attributes, suggesting that these resources are *not* additional. For example, Texas is home to more than 41 GW of wind energy, with a large concentration of wind projects in the western part of the state. Wind projects were developed in Texas because they were economically viable even without compensation for their environmental attributes. Indeed, because of the abundant supply, prices of RECs from Texas renewable projects are much lower than REC prices in regions such as PJM and ISO-New England.[32] Thus, additionality is not synonymous with new resources; additional resources need not be new, and new resources need not be additional.

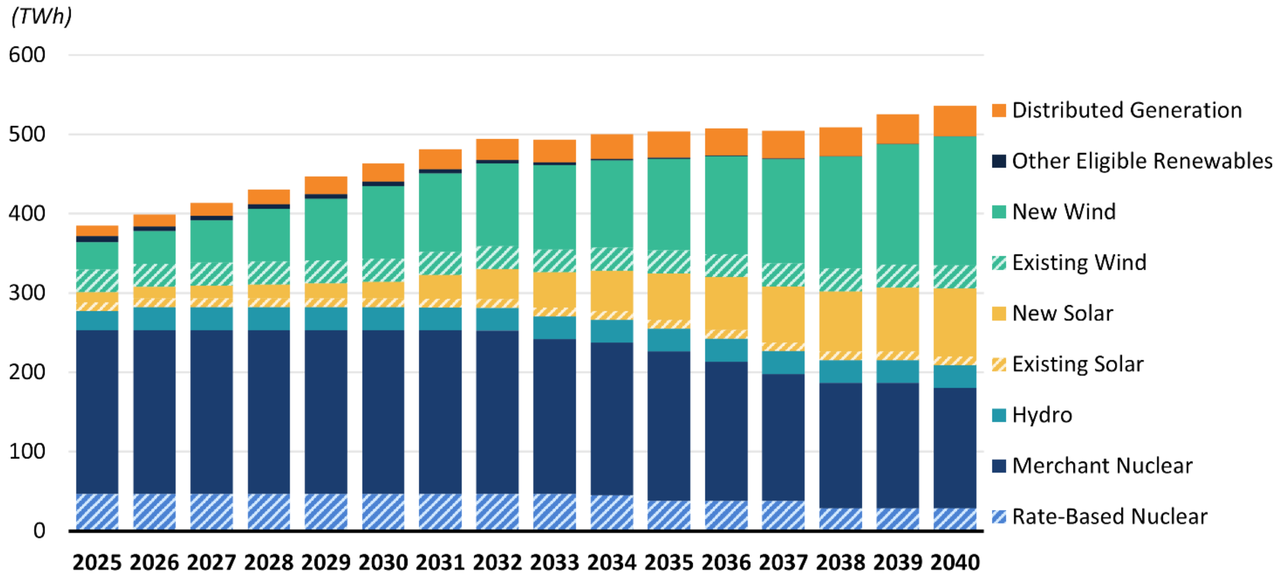
As an alternative indicator of additionality, we can examine the balance between CFE supply and demand. Rather than focusing narrowly on whether a clean resource is new or existing, the emphasis can be on whether aggregate market demand is sufficient to stimulate additional clean energy deployment at a system-wide level. Put differently, in power systems where aggregate CFE demand (including demand from compliance programs and voluntary procurement programs) exceeds total available CFE supply, new clean energy resources would be needed to meet that demand, and such resources would qualify as additional.

To examine the applicability of CFE scarcity as a proxy for the additionality requirement, we evaluated the supply and demand for CFE in PJM and how they evolve over time. Using current data, along with known policy and market developments, we estimated the total CFE supply in PJM between 2024 and 2040. The major sources of CFE supply include:

- **Utility-scale renewable generation:** In addition to the existing renewable generation, we assume that new renewable resources will be added to the PJM power grid to meet member states' RPS obligations.
- **Nuclear generation:** Generation from nuclear power plants can be used to meet CFE procurement goals. We modeled the operational status of the plants based on the latest announcements and known retirement plans.
- **Distributed generation (DG):** Some jurisdictions allow DG generation (e.g., generation from rooftop solar PV) to meet their RPS obligations.

[32] Lawrence Berkeley National Laboratory, *Land-Based Wind Market Report* (2024). In addition, a new wind project sited in West Texas would have limited carbon-abatement value because that part of the state's power system is already relatively clean.

FIGURE 3: PROJECTED SUPPLY OF CARBON-FREE ENERGY IN PJM



Source and Notes: Brattle analysis. For further detail on the assumptions made for each category of CFE supply, please refer to Appendix VII.A.

The projected annual CFE supply from 2025 to 2040 is shown in Figure 3. We estimate that the total CFE supply in PJM will increase from 385 TWh in 2025 to 536 TWh in 2040, or about a 39% increase. The volume of new wind and solar capacity reflects the significant increase in RPS obligations across the PJM member states.[33] There is some fluctuation in nuclear generation due to plant retirements. According to PJM's latest load forecast, distributed generation in PJM is expected to approximately double during the study period.[34]

Next, we estimated the CFE demand in PJM, which comes from the following sources:

- **RPS obligations:** Demand for CFE will increase as PJM member states will need more clean generation to meet their RPS requirements.[35]
- **Rate-based nuclear**: The clean attributes associated with generation from nuclear plants owned by utilities and paid for by their ratepayers are claimed by the ratepayers and cannot be sold to another party.

[33] Instead of building new renewable resources or purchasing RECs, compliance entities can also pay a penalty fee through the alternative compliance mechanism. We assume the use of ACP will be limited.

[34] PJM, 2024 Preliminary PJM Load Forecast (November 27, 2023).

[35] Our analysis assumes that renewable energy resources will be added only to meet states' RPS obligations. Adding enough renewable energy capacity just to keep pace with the RPS requirements is already challenging, especially given the long interconnection queues and the high load growth environment.

- **State support programs:** States such as Illinois and New Jersey have established programs to provide financial support to existing clean energy resources (e.g., nuclear plants). Programs such as the Zero-Emission Credit program and the Carbon Mitigation Credit program procure and retire certain volumes of EACs from existing nuclear plants in those states.
- **Voluntary demand:** Voluntary demand takes the form of power purchase agreements (PPAs), purchases of unbundled RECs, and miscellaneous utility green energy programs.

We consider three scenarios for voluntary CFE demand:[36]

- **CEBA/Wood Mackenzie projection:** The Clean Energy Buyers Association (CEBA) recently released a forecast of corporate procurement levels, indicating that corporate demand for CFE in PJM will grow by approximately 5% year over year between 2025 and 2035.[37] This is considered the "Low" scenario.
- **Historical growth rates**: Using an NREL database, we calculated the compound average national growth rate (CAGR) of voluntary CFE demand over the past three years (10.6%) and five years (16%).[38] The three-year CAGR is considered the "Medium" scenario and the five-year CAGR is considered the "High" scenario.

The projected CFE supply and demand between 2025 and 2040 are shown in Figure 4 below. The CFE supply (shown as the bars) is the total across the categories shown in Figure 3 above. The projected, non-voluntary demand (shown as the dashed gray line) coupled with the voluntary demand makes up the total CFE demand (shown as alternative solid lines). The decrease in total demand from 2025 to 2028 reflects the expiration of the Illinois and New Jersey state support programs, before steadily increasing with the expansion of RPS targets.

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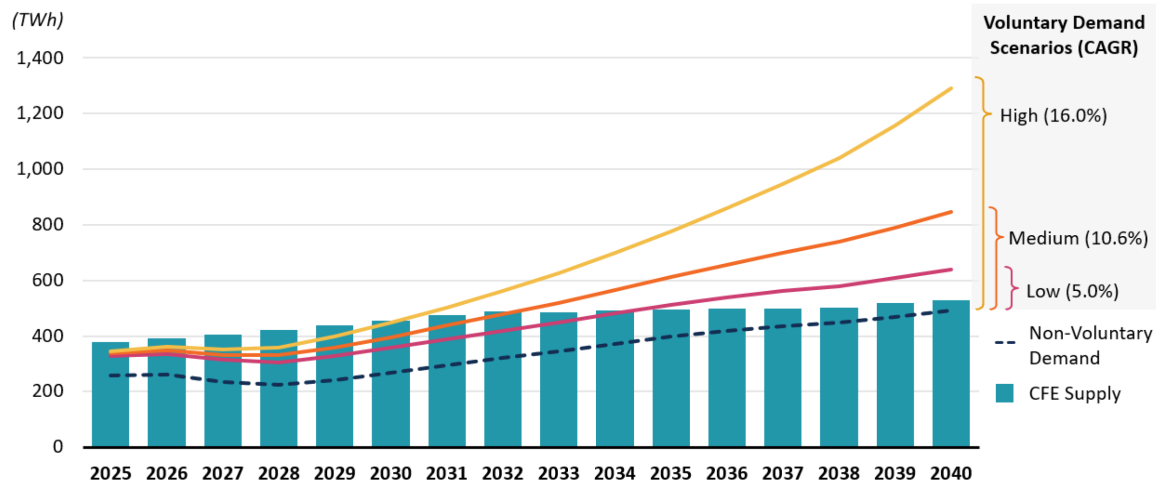
[36] The voluntary CFE demand growth rate calculations include demand for unbundled RECs, which are generally inexpensive; it is possible such demand may decrease at higher REC prices. In general, we did not consider how CFE demand would change with the price of clean energy instruments, as information on price elasticity of demand is limited.

[37] In this report, CEBA and Wood Mackenzie project corporate demand for carbon-free energy by region based on current procurement among Fortune 1000 companies and projected demand growth across sectors. Importantly, it assumes that these companies will not adjust their clean energy procurement targets. To derive the CEBA projection, the assumption is that CEBA uses the term demand to refer to contracted demand under a PPA. The 2035 projection of 54.3 GW of demand under PPAs in PJM is used alongside a 24% capacity factor (equivalent to PJM's 2023 capacity-weighted average of wind and solar) to derive a compound average growth rate of approximately 5%. CEBA & Wood Mackenzie, *US Corporate Carbon Emissions-Free Demand Outlook* (January 2025).

[38] NREL, *Status and Trends in the Voluntary Market (2023 Data)* (2024).

FIGURE 4: PJM'S CFE SUPPLY AND DEMAND BALANCE UNDER THREE VOLUNTARY PROCUREMENT SCENARIOS



Note: The low (CEBA), medium (3-year CAGR), and high (5-year CAGR) voluntary CFE demand scenarios correspond to different assumptions about the annual average growth rate applied to the current voluntary CFE demand. The magnitudes of the voluntary CFE demand scenario lines include non-voluntary demand for CFE, represented by the dashed gray line. The difference in magnitude between each scenario and the non-voluntary CFE demand line represents the magnitude of the voluntary demand for CFE.

As Figure 4 demonstrates, the year in which CFE demand is expected to exceed CFE supply ("cross-over year") depends on the voluntary demand growth rate.[39] If the actual voluntary demand growth resembles the CEBA (Low) projection, available CFE supply would run out around 2035. At that time, total commercial and industrial (C&I) load in PJM is expected to be about 850 TWh, meaning that approximately 12% of total C&I load would be procured as CFE under the CEBA scenario. For reference, this is approximately the same share (13%) of C&I load that is procured as CFE today.[40] If, instead, the voluntary demand growth rate resembles the 5-year historical CAGR (High), the available CFE supply would be exhausted before 2031, with about 27% of C&I load being procured as CFE.

At a high level, we find it is only a matter of time before the growing total CFE demand in PJM will exceed the total CFE supply – sometime in the 2030s. At that point, meeting all the CFE demand would require adding new resources, so the additionality requirement would already be met. This means that a focus on just new rather than all clean resources would not be necessary. A holistic procurement strategy that includes all clean resources – existing and new – can ensure that existing resources will remain operating and new projects will continue to be developed.

39 While the cross-over year is highly sensitive to the growth rate in voluntary demand for CFE, even if it is completely stagnant, we expect that by 2040 available supply will be completely exhausted due to the increases to RPS requirements along with planned nuclear retirements.

40 The small decrease in share of C&I load is a result of the significant load growth projected in PJM, which will outpace the growth rate of demand for C&I, which is estimated separately.

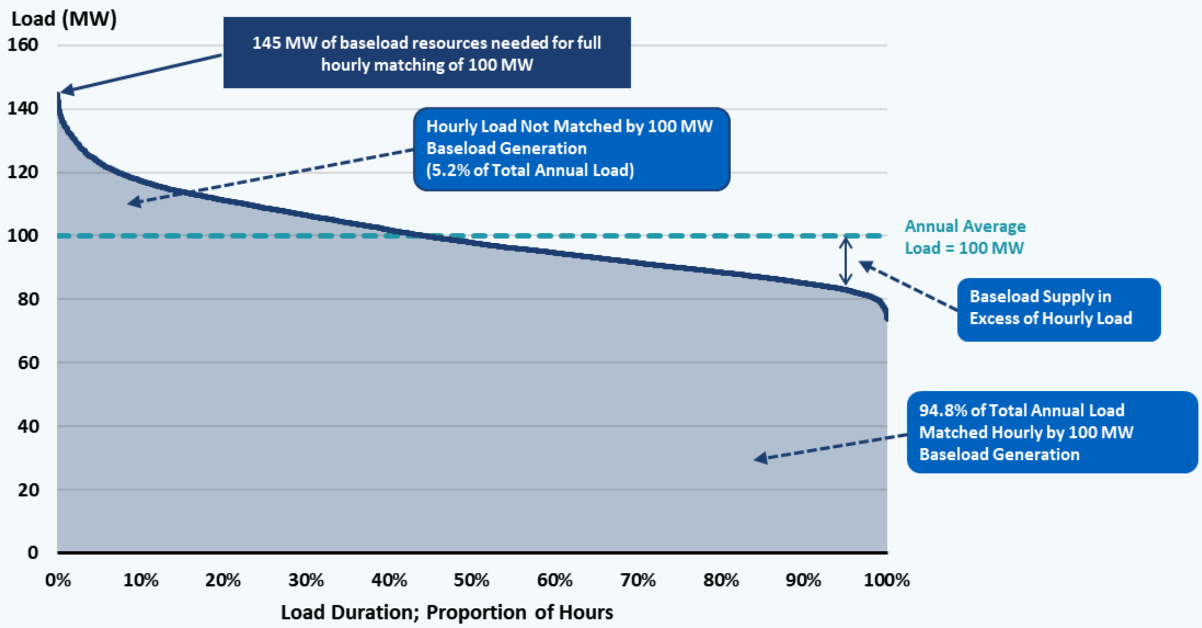
Hourly versus Annual Energy Matching

Elsewhere in this paper, we assume that clean energy accounting is done on an annual basis – acquiring clean energy supply sufficient to match total annual demand, without regard to the precise timing of supply and demand. An alternative is hourly accounting (also called 24/7 CFE accounting), which requires that electricity demand be matched with clean supply produced in the same hour the power is used (as well as on the same regional grid, or deliverable to it). Companies like Google and Microsoft are pursuing 24/7 CFE goals, and the United Nations is leading a global 24/7 CFE effort. The GHG Protocol's Scope 2 working group is also considering such requirements for inventory accounting.

How well a specific supply resource matches a specific load depends, of course, on the hourly pattern of the supply and the demand being considered. For example, flat baseload supply is a good hourly match for an unchanging 24/7 industrial load, whereas solar generation would be a bad match for streetlighting load. If the grid were fully clean, hourly matching for all loads would be a natural consequence of matching the supply to demand in real time. While the grid is still only partially clean, customers interested in clean energy can move toward that temporal shaping by using hourly accounting to more closely align the timing and location of their own clean energy procurement with their energy consumption.

During this transition period, annual matching will typically result in at least partial hourly matching. To illustrate, using a representative aggregate PJM C&I load shape that averages 100 MW, an annually matched portfolio of idealized baseload (constant 100 MW output in all hours) provides quite a good hourly match – nearly 95% of MWh are matched with contemporaneous hourly generation, as depicted in the figure below. (In this example, full 100% hourly matching would require 145 MW of baseload supply to meet the peak hour load; that would result in surplus clean energy in other hours that could satisfy other CFE demand that requires only annual matching.) Intermittent renewables do not match as well on an hourly basis, yet still typically match 70 to 75% of load with contemporaneous hourly generation (based on a 50/50 portfolio of wind and solar, approximately the ratio in PJM, and the same PJM C&I load shape). Both scenarios illustrate that with hourly matching, a shortfall of available CFE may exist in some hours, depending on the hourly alignment of the supply and demand, and an overall shortage of CFE in any single hour (total hourly CFE demand above that hour's total CFE supply) would incentivize adding new clean resources that can generate in that hour. With annual matching, new supply is incentivized only once aggregate annual demand exceeds aggregate annual supply.

FIGURE 5: ANNUAL VS. HOURLY MATCHING FOR REPRESENTATIVE C&I LOAD



Sources and notes: Hourly load shape based on Duquesne Light Co.'s 2023 small, medium, and large C&I loads, from https://www.duquesnedsp.com/Documents/LoadandOtherData.aspx.

– Google, "The Internet is 24x7—carbon-free energy should be too" (September 2019). Microsoft, "Made to measure: Sustainability commitment progress and updates" (July 14, 2021). See also the 24/7 Carbon-Free Energy Compact, https://gocarbonfree247.com/the-movement/.

– Michael Macrae and Kyla Aiuto, "GHG Protocol Standards Update Process: Topline Findings From Scope 2 Feedback," Greenhouse Gas Protocol (May 2, 2023).

VI. Implications for Clean Energy Procurement Policy

Achieving deep GHG emissions reductions requires leveraging both existing and new clean energy resources. While the addition of new clean generation is essential to meeting state-level clean energy policy targets, it is also important to retain existing clean generation. Evidence shows that the closure of clean power resources, such as nuclear plants, has historically resulted in increased emissions, because the output of the retiring clean resource is replaced largely by fossil generation (mostly gas-fired).

Since 2012, more than 10.2 GW of nuclear generating capacity has been retired or mothballed, and on an annual basis, the lost generation from these resources is equivalent to about 13% of the total electricity currently generated by wind, solar, and biomass combined in 2023.[41] We show that similar outcomes are likely in the future if existing clean energy resources are retired, with resulting increases in system-wide emissions due to partial replacement by natural gas, particularly in the near term.

Importantly, it is unlikely that incremental new clean energy resources (more than would be added otherwise) would be deployed in time to fully replace a retiring nuclear reactor. Current interconnection delays and transmission constraints have slowed the pace at which renewables can be brought online, even to meet existing RPS goals, much less to add incrementally more new clean resources to replace the loss of an existing resource. In PJM, for instance, about 300 GW of projects are in the interconnection queue, the overwhelming majority consisting of wind and solar projects.

Further, projects completed in recent years required a median of nearly five years from interconnection request to commercial operation. These delays coincide with a period of rapidly rising electricity demand. To meet this demand, some utilities have turned to new natural gas development and/or delayed the retirement of coal plants.[42] Thus, it may be unlikely that a loss of existing clean generation would or could be replaced by increased new clean generation in the near term, beyond what is already being developed.

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[41] To calculate this share, we compare the generation of retiring or mothballed nuclear generating units in the year prior to their retirement to the estimated annual generation from renewables in the United States. Data from S&P Global, Market Intelligence, the Congressional Research Service, and the Energy Information Administration's Electricity Data Browser.

[42] Gaffney and Rojanasakul, "Where Coal is Retiring, and Hanging On," https://www.nytimes.com/interactive/2025/02/06/climate/coal-plants-retirement.html

While the loss of existing clean resources may increase emissions if it is replaced by conventional emitting generation, it may also pose reliability challenges if it is replaced instead by only intermittent renewable generation. As renewable deployment such as wind and solar increases, the marginal system reliability value of additional renewable capacity tends to decline.

Existing clean energy resources are facing increasing economic pressure in competitive markets. As more new renewable resources are added to the power system, average energy prices decline, because renewable generators tend to bid into wholesale markets at or below zero price to ensure their dispatch and secure production-based tax credits. Subject to transmission and operational constraints, system operators always select and dispatch renewable generation first due to their lower variable cost. Low market-clearing prices, in turn, reduce the market revenues that existing clean energy resources like nuclear and hydropower receive.

This dynamic poses a particular challenge for merchant clean generators that lack long-term revenue assurance. In vertically integrated markets, state regulators can direct utilities to retain legacy clean resources, allowing them to recover costs from ratepayers. However, merchant generation owners in restructured markets do not have access to comparable mechanisms and are therefore more vulnerable to market conditions. Without adequate support, existing clean assets may face challenges to their economic viability – even when they are among the most cost-effective sources of zero-emission electricity.

While time-limited measures such as the ZEC programs and the 45U tax credit may serve as effective stopgap measures, these measures will expire, and existing clean energy resources will then be exposed to low prices and market risks. Indeed, our analysis indicates that many nuclear plants in PJM are projected to operate at very low or negative margins by the early 2030s with the scheduled expiry of the 45U tax credit. Even those that remain marginally profitable will face uncertain long-term financial viability due to persistently low net revenues.

To ensure cost-effective and reliable progress toward clean energy goals, substantial amounts of new renewable generation must of course be added. However, the contributions of existing clean generation assets must also be acknowledged to ensure that these assets will continue to operate into the future. It will likely be necessary to develop and implement mechanisms in a forward-looking framework that explicitly values the clean energy attribute of all new and existing resources.

Maintaining broad eligibility for voluntary clean energy procurement is one way to support existing clean energy resources. A comprehensive emissions accounting and clean energy procurement framework would ensure that both new and existing clean resources are recognized and credited for their contributions to reducing GHG emissions. Efforts toward creating such a framework are underway (e.g., the GHG Protocol's Scope 2 revision and the SBTi's Net-Zero Standard V2). However, that framework should not interpret an additionality requirement to mean "new". Such an interpretation would, by definition, exclude existing clean resources from participating in voluntary CFE procurement markets and deprive them of an important revenue stream that could support their continued viability.

Moreover, looking at PJM, where merchant nuclear plants make up a large share of available clean resources, we show that if CFE demand continues to grow at recent rates, CFE demand will exceed overall clean supply (including merchant nuclear plants) by the early to mid-2030s. At that point, demand for CFE would lead to additional clean energy deployment. Using available CFE supply as an indicator for additionality would obviate concerns that existing resource eligibility might flood the CFE market and dampen demand for new resources.

In the public policy arena, some jurisdictions have begun to explore clean energy mechanisms that explicitly value the clean capacity that different resources can offer without differentiating between new and existing resources. For example, in states with existing clean energy standards, zero-emitting resources are generally all treated equally. Another example that is being considered in several regions is the concept of a clean capacity product or certificate.[43] Further, organized markets already offer precedents for recognizing and compensating a particular energy service regardless of whether the underlying resource is new or existing. Markets routinely value and compensate generating resources for the different services that they provide, such as energy, and ancillary services like ramping and operating reserves.

As market dynamics evolve and states and companies continue to make progress toward their ambitious clean energy targets, it is critical to recognize the contributions of legacy clean resources and the risks they face, and to acknowledge their clean attributes in ways that can support their continued operation. A unified emissions accounting and clean energy procurement framework can play a central role in guiding the development of clean energy policy to support

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[43] We are aware of multiple jurisdictions pursuing the idea of a clean capacity product or certificate. For example, the New Jersey Board of Public Utilities Staff recommends the creation of clean capacity certificates (CCC) via a state-run program or constraints in the capacity market, where one CCC represents the clean attribute of 1 MW of capacity for a particular year or season. *See* New Jersey Board of Public Utilities, *2022 Progress Report on New Jersey's Resource Adequacy Alternatives – Update Regarding Staff's Investigation of Resource Adequacy Alternatives,* Docket #EO20020203 (March 2023). Similarly, the Illinois Renewable Energy Access Plan includes discussion of whether clean capacity product would help smooth the state's clean energy transition. *See* Illinois Commerce Commission, *Renewable Energy Access Plan*, Section V.D (May 30, 2024). Lastly, the Massachusetts Department of Energy Resources is considering a centralized 3-year forward auction market for various clean energy products that would include a CCC. *See* Massachusetts Department of Energy Resources, *New England Forward Clean Energy Markets—Proposed Market Rules*, Version 1 (January 2023).

efficient and durable decarbonization outcomes. Ultimately, maintaining a diverse and economically sustainable portfolio of clean energy resources – both new and existing – is essential to achieving a reliable, affordable, and decarbonized electricity future.

VII. Appendix

A. Carbon-Free Energy Supply & Demand Modeling Framework

We used a bottom-up approach to estimate the annual volumes of CFE supply and demand in PJM. Equation 1 below describes the input used to calculate the available CFE supply. We describe each input in more detail below.

EQUATION 1: CALCULATION OF THE CFE SUPPLY AND DEMAND BALANCE

$$Available\ Carbon\ Free\ Energy = Total\ Supply - Total\ Demand$$

Where:
Total Supply (in MWh) = Nuclear (Rate-Based + Merchant) + Distributed Generation + Renewables (Solar, Wind, Hydro, and Other Eligible Renewables)
Total Demand (in MWh) = Nuclear (Rate-Based) + PJM's RPS + Incremental PJM CES + State ZEC/CMC* Demand + Voluntary CFE Demand

* Note: ZEC/CMC refers to generation that falls under state Zero-Emission Credit and Carbon Mitigation Credit programs in Illinois and in New Jersey.

MERCHANT NUCLEAR GENERATION (SUPPLY)

There are 18 nuclear power plants located and operating in PJM member service territory, 15 of which are merchant generators (see Table 2 below). We determined the annual generation by multiplying each plant's capacity by the 2022 to 2024 historical average rated capacity factor for the PJM nuclear fleet (92%). We accounted for the expiration of each unit's current operating license. When a plant is scheduled to retire in the middle of a year, we prorated the annual generation by the number of days the plant is online in that year.

TABLE 2: MODELED NUCLEAR PLANT RETIREMENTS BEFORE 2050

Plant Name	Unit	Modeled License Expiration Date
Beaver Valley	1	1/29/2036
Beaver Valley	2	5/27/2047
Braidwood Generation Station	1	10/17/2046
Braidwood Generation Station	2	12/18/2047
Byron Generating Station (IL)	1	10/31/2044
Byron Generating Station (IL)	2	11/6/2046
Calvert Cliffs Nuclear Power Plant	1	7/31/2034
Calvert Cliffs Nuclear Power Plant	2	8/13/2036
Crane Clean Energy Center ☆	1	~2048
Davis Besse	1	4/22/2037
Donald C Cook	1	10/25/2034
Donald C Cook	2	12/23/2037
Hope Creek	1	4/11/2046
LaSalle	1	4/17/2042
LaSalle	2	12/16/2043
Limerick	1	10/26/2044
Limerick	2	6/22/2049
Peach Bottom	2	8/8/2053
Peach Bottom	3	7/2/2054
Perry (OH) ★	1	11/7/2046
PSEG Salem Generating Station	1	8/13/2036
PSEG Salem Generating Station	2	4/18/2040
Quad Cities (Constellation)	1	12/14/2032
Quad Cities (Constellation)	2	12/14/2032
Susquehanna	1	7/17/2042
Susquehanna	2	3/23/2044

Assumed that Dresden units both receive 20-year license extensions

☆ Assumed that Crane Clean Energy Center Unit 1 resumes operation in 2029

★ Assumed that Perry receives a 20-year license extension

We made several manual adjustments to properly account for the unique conditions applicable to certain nuclear plants:

- MidAmerican Energy owns 25% of the Quad Cities Clean Energy Center nuclear plant. Because MidAmerican is a MISO member, we excluded 25% of Quad Cities' total generation from the total merchant generation in each year.

- Generation from the following nuclear units was accounted for but subtracted from the available supply. The output (energy and EACs) from these plants is already partially or wholly contracted with customers:
  - Susquehanna Units 1 & 2; 960 MW of total generation capacity is excluded.[44]
  - Unit 1 at Three-Mile Island is expected to return online as a merchant generator in 2029. We modeled 976 MW of nameplate capacity from this date through the remainder of the modeling horizon. However, generation from this nuclear plant is contracted for by Microsoft.

UTILITY-OWNED NUCLEAR GENERATION (SUPPLY)

There are three nuclear power plants in PJM that are owned and operated by regulated utilities: Donald C. Cook Nuclear Plant (owned by Indiana Michigan), North Anna Nuclear Generating Station (Dominion), and Surry Power Station (Dominion). We estimated their annual generation using the same method as generation from the merchant nuclear plants.

DISTRIBUTED SOLAR GENERATION (SUPPLY)

Generation from distributed solar in PJM is based on PJM's publicly available preliminary 2024 load forecast.[45] We assumed a 15% capacity factor to calculate the total generation from distributed solar in PJM.

RENEWABLE GENERATION (SUPPLY)

We estimated the annual solar and wind generation using a bottom-up approach, relying on state-specific characteristics and clean energy policy goals and targets. Each state's RPS target is represented as a binding constraint, meaning that each state's annual renewable generation must meet its RPS obligation.

Each state's renewable generation is the product of:

- The forecasted retail load, accounting for the share of the state's electricity demand that is in PJM;
- The state's RPS target, extrapolated linearly; and
- The percentage of retail sales in each state subject to the RPS.

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[44] Ethan Howland, "Talen-Amazon interconnection agreement needs extended FERC review: PJM market monitor," *Utility Dive* (July 11, 2024) https://www.utilitydive.com/news/talen-amazon-interconnection-agreement-ferc-constellation-vistra/721066/.

[45] PJM, *Preliminary 2024 PJM Load Forecast* (November 27, 2023), Slide 16.

For example, based on retail sales, we assigned 66% of Illinois' total load to PJM. The state's RPS target in 2032 is 40%, which only applies to investor-owned utilities and competitive retail suppliers, representing around 93% of total retail sales. So Illinois's contribution to renewable supply in 2032 is the state's total load in 2032 multiplied by the 66% of the state that participates in PJM, 40% RPS target, and the 93% of covered retail sales.

We developed the retail load forecasts using a combination of historical data and projected growth rates from Brattle's gridSIM model. The first year of state data (2023) is from the Lawrence Berkeley National Laboratory's (LBNL's) dataset of statewide retail electricity sales, which uses sales data from the EIA's Form 861.[46] Next, state load values for Illinois, Indiana, Kentucky, Michigan, and North Carolina were reduced using scalar factors to account for the percentage of each state that participates in PJM. Using this method, about 66% of Illinois, 15% of Indiana, 35% of Kentucky, 3% of Michigan, and 3% of North Carolina retail load participate in PJM. Lastly, we multiplied the historical data from LBNL by the anticipated annual growth rates of retail load from gridSIM to obtain annual retail load projections for each state. The LBNL dataset also provides RPS targets by state and year. We note that in some cases, the RPS target is not applicable to a state's entire retail load.[47]

We determined the shares of renewable generation by each resource type (hydro, solar, wind, and other renewables) using output from gridSIM. First, we subtracted the estimated hydroelectric generation from the annual renewable generation, reflecting that relatively constant hydro generation across years. We then applied year-over-year generation shares of wind, solar, and other renewables (derived from gridSIM modeling) to the remainder of the retail sales. Finally, we disaggregated the renewable generation data into existing and new wind and solar generation in each year.

UTILITY-OWNED NUCLEAR GENERATION (DEMAND)

We modeled the demand and supply of nuclear generation from power plants owned and operated by utilities using the same method. This generation is included on the demand side of the model because the clean attributes of the electricity from the rate-based nuclear plants should be considered claimed by the utility's customers.

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[46] LBNL, *US State Renewables Portfolio & Clean Electricity Standards: 2024 Status Update* (August 2024).

[47] For example, Virginia's RPS is only applicable to Dominion and Appalachian Power. In 2023, sales to customers of those two utilities comprised 76% of total retail sales in Virginia.

RENEWABLE PORTFOLIO STANDARDS (DEMAND)

We modeled the supply of renewables and CFE demand from RPS programs using the same method. Clean energy attributes must be retired to meet the RPS obligations, constituting a source of CFE demand.

INCREMENTAL PJM CLEAN ENERGY STANDARDS (DEMAND)

Illinois, Michigan, Maryland, and New Jersey each have standalone clean energy targets that are beyond their RPS targets:

- Illinois has a clean energy goal of 100% by 2050, which was established as part of the Climate and Equitable Jobs Act (CEJA). We linearly interpolated the target from 2021, the year CEJA was announced, to 2050.
- Michigan has a clean energy standard of 80% by 2035 and 100% by 2040 that was enacted under the Clean Energy Future program in 2023. We modeled the targets by first linearly interpolating between 0% and 80% between 2023 and 2035 and then interpolating between 80% and 100% between 2035 and 2040.
- Maryland has a clean energy goal of 100%, which was established in June 2024 through an executive order. We modeled this target by linearly interpolating from 0% to 100% between 2024 and 2035.
- New Jersey has a clean energy goal of 100%, which was established in 2023 through Executive Order 315. We modeled this target by linearly interpolating from 0% to 100% between 2023 and 2035.

Clean energy standards and targets are a binding constraint in the model. In a jurisdiction with both an RPS and a clean energy standard or target, we set the demand for clean energy as the higher of the two.

STATE SUPPORT PROGRAMS (DEMAND)

State support programs refer to clean energy procurement programs designed by states to provide financial support to clean energy sources (separate from RPS policy). Key state support programs in the PJM region include:

- **Illinois Zero-Emission Credit program:** Investor-owned utilities with more than 100,000 customers must procure a quantity of zero-emission credits equal to 16% of their 2014 retail sales. We estimate that for its PJM portion, Illinois would procure a quantity of ZECs equal to approximately 14.2 TWh. The program is set to expire in May of 2027.

- **Illinois Carbon Mitigation Credit program:** In addition to the Illinois Zero-Emission Credit program, the Illinois CMC program provides financial support to nuclear plants by awarding credits to ensure their continued operation as a zero-carbon energy source. The program calls for the procurement of approximately 54.5 million credits. It is set to expire in May of 2027.
- **New Jersey Zero-Emission Credit program:** All nuclear generation in New Jersey is covered under the state's zero-emission credit program, which provides financial support in the form of per-MWh credits. The program is set to expire in May of 2025.

In the year in which a program expires, we prorated the annual procurement volumes.

VOLUNTARY DEMAND

We developed three voluntary CFE demand projections for this analysis. Each of the following annual growth rates were applied to our estimate of PJM's demand for CFE in 2023.[48]

- **3-Year CAGR:** In 2023, NREL released an update to its annual *Status and Trends in the Voluntary Market* report that includes historical data on annual voluntary demand for clean energy.[49] The compound annual growth rate of total US demand for clean energy from 2021 to 2023 was 10.6%.
- **5-Year CAGR:** Using the same NREL source, we calculated the compound annual growth rate of total voluntary demand for clean energy in the US from 2021 to 2023 was 16.0%.
- **CEBA:** A recent publication from CEBA and Wood Mackenzie projected that in 2035, PJM would have 54.3 GW of demand for CFE.[50] After converting to energy terms, this translates into a 5.0% compound average growth rate from 2023.[51]

B. GridSIM

gridSIM is The Brattle Group's proprietary long-term electricity simulation and capacity expansion model. Brattle developed gridSIM to analyze how clean energy policies and technological change would affect future market outcomes, particularly in high-renewable futures. Like most capacity expansion models, gridSIM identifies the least-cost expansion plan while considering the basics

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48 Our estimate of 2023 total CFE demand in PJM is based on NREL's state-level data on voluntary demand. State totals were adjusted for PJM membership using retail sale percentages. We assume that all existing demand for CFE will continue to exist in future years. NREL, *Status and Trends in the Voluntary Market (2023 Data)* (2024).

49 NREL, *Status and Trends in the Voluntary Market (2023 Data)* (2024).

50 CEBA & Wood Mackenzie, *US Corporate Carbon Emissions-Free Demand Outlook* (January 2025).

51 To convert 54.3 GW to energy terms, we scale the capacity using a 24% capacity factor, equivalent to PJM's 2023 average capacity factor for wind and solar, weighted using the 2023 installed capacity.

of electricity demand and supply, transmission, regulation, policy, and market design. The results of this analysis rely on gridSIM results that were developed for the *Economic Impacts of Relicensing the Dresden Clean Energy Center (DCEC)* report and reflect a snapshot of expectations as of September 2024.[52] The version of the model used was designed to represent the joint PJM-MISO system with appropriate transmission limit constraints between the two RTOs. Table 3 below summarizes the important modeling features and assumptions.

[52] The Brattle Group, *Economic Impacts of Relicensing the Dresden Clean Energy Center* (March 12, 2025).

TABLE 3: IMPORTANT GRIDSIM MODELING FEATURES AND ASSUMPTIONS

Modeling Feature/Assumption	Description
Modeling Topology	gridSIM employs a pipe and bubble framework optimizing capacity expansion and generation across both MISO and PJM, representing 11 zones with interchange limits calibrated using EPA's Integrated Planning Model transmission limits and EIA historical interchange data.[53,54] MISO's 10 local resource zones are aggregated into four zones (West, Central, East, and South), while PJM's 21 transmission zones are modeled as seven energy zones and four capacity zones, creating a comprehensive regional representation that allows for analysis of cross-system power flows and resource adequacy.
Modeled Policies	The gridSIM model incorporates a comprehensive set of energy policies across PJM and MISO regions, including state-level renewable and clean energy targets (with technology-specific procurement requirements) and emissions reduction goals based on state and utility decarbonization commitments. Federal policies are represented through the Inflation Reduction Act's PTCs for solar, onshore wind, nuclear, and hydrogen generation, plus investment tax credits for offshore wind and battery storage, alongside Section 45Q tax credits for carbon capture and storage. The model specifically addresses Illinois' Climate and Equitable Jobs Act (CEJA) by implementing a 2045 zero-emissions deadline with linearly decreasing emissions limits and a phased retirement/retrofit schedule for fossil fuel units based on their emissions profiles and proximity to environmental justice communities, with cumulative coal and gas retirement timelines established by the Illinois Department of Labor.[55,56]
Load Growth	The gridSIM model incorporates regional-specific load growth assumptions for both PJM and MISO. For PJM, load forecasts are based on the PJM 2024 Load Forecast Report,[57] which includes projections for electric vehicles, heating load (derived from NOAA heating degree day data), and behind-the-meter generation. MISO's load growth utilizes the 2023 MISO Independent Energy and Peak Demand Forecast by Purdue University[58] as a baseline through 2050, supplemented with anticipated electric vehicle adoption from MISO's Futures Report (Future 2A)[59] with EV load shapes from the US DOE EVI-Pro Lite tool, and projected electrified heating uptake based on MISO's Futures Report (Future 2).[60]

53 EPA's Integrated Planning Model (v6 2021 Reference Case). Transmission limits from Table 3-20 "Annual Transmission Capabilities of US Model Regions" (September 2021).

54 EIA Dashboard.

55 See Clean Energy and Jobs Act (CEJA) and EGU Requirements for further details.

56 IL Department of Labor (February 2023).

57 *PJM 2024 Load Report* (January 2024).

58 *Purdue 2023 MISO Forecast Report* (November 2023).

59 *MISO Series 1A Futures Report* (November 2023).

60 EVI-Pro Lite.

C. Nuclear Plant Economic Viability Analysis Framework

We assessed the economic viability of nuclear units in PJM by calculating the net revenues associated with a representative plant. We calculated net revenues by subtracting avoidable costs from total gross revenues, which include energy payments, capacity payments and the PTC.

REVENUES FROM ENERGY AND CAPACITY PAYMENTS

We used energy and capacity price data from NREL Cambium 2023 to calculate energy and capacity revenues. Cambium 2023 includes eight scenarios for the US electricity sector. Our analysis includes six of these eight scenarios:

- A Mid-Case, which includes moderate estimates for technology and fuel costs, limited nascent technologies, and 2023 electric sector policy commitments;
- Low and high renewable energy and battery costs cases;
- A high demand growth case, where load is assumed to grow in accordance with electrification and economy-wide decarbonization; and
- Low and high natural gas cost cases.

We excluded the two deep decarbonization scenarios, which have highly stringent carbon constraints.

The Cambium model provides energy and capacity prices for each balancing area (BA) in the US for every 5 years between 2025 and 2050. We interpolated between model year prices to obtain prices for intermediate years. Cambium provides model results in $2022, which were converted to nominal dollars for this analysis.

All of the Cambium cases considered generally show energy prices declining moderately through 2030 and then staying relatively constant in real terms through the end of the study horizon. To calculate the energy and capacity revenue received by PJM nuclear plants, we mapped operational nuclear plants to their corresponding BA and assumed a constant generation profile. Under a constant generation profile, the average annual energy and capacity revenue per MWh received by a hypothetical nuclear plant is equal to the average annual energy and capacity price for the BA as determined by the Cambium model.

RECEIPTS FROM PRODUCTION TAX CREDIT

Under the 45U tax credit, the PTC amount available to each nuclear plant varies as a function of its gross receipts. For this analysis, we assume that gross receipts are a sum of capacity and energy revenues as calculated in the previous section. We calculated the PTC as:

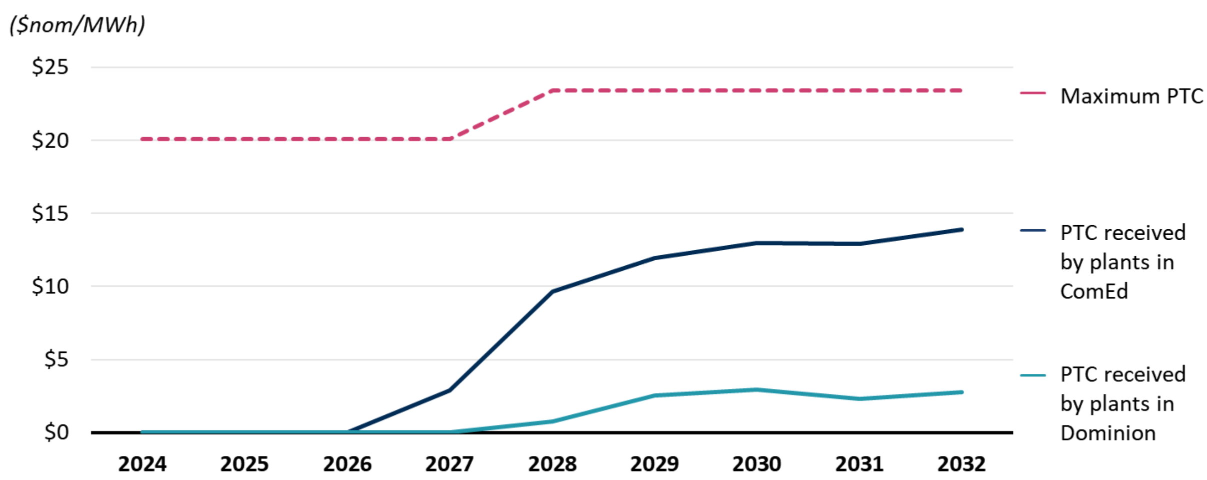
EQUATION 2: GROSS RECEIPTS FORMULA FROM 26 U.S. CODE § 45U[61]

PTC Payment = 5 × [3 × (Eligible MWh Sales) − 16% × (Gross Receipts − 25 × Eligible MWh Sales)]

All MWh generated by the plant were assumed to be eligible sales. The PTC is configured such that if a plant's gross receipts exceed $25/MWh, the $15/MWh tax credit provided to facilities meeting the prevailing wage requirement will be reduced by a portion of the excess. Both the $25/MWh and $3/MWh base tax credit terms of this equation are adjusted in $1/MWh and $0.5/MWh increments with inflation over time, in accordance with 45U. We assume the representative nuclear plant in this study meets the prevailing wage requirements to receive five times credit.

With assumed energy and capacity receipts from NREL Cambium prices and typical costs, none of the PJM nuclear plants studied in this analysis can claim the maximum tax credit possible, of approximately $20/MWh by 2032, in the case of tax credit extension. Tax credits received by plants vary between $6–$14/MWh by 2032, with the highest tax credits received by plants in northern Illinois (ComEd), and the lowest tax credits received by plants in Virginia (Dominion). (see Figure 6 below).

FIGURE 6: TAX CREDITS MODELED IN ECONOMIC VIABILITY ANALYSIS



Notes: Stepwise change in the maximum PTC is a byproduct of the inflation adjustment mechanism as specified in the 45U. Inflation adjustment specifies that adjustments made to the $3/MWh base tax credit must be rounded to

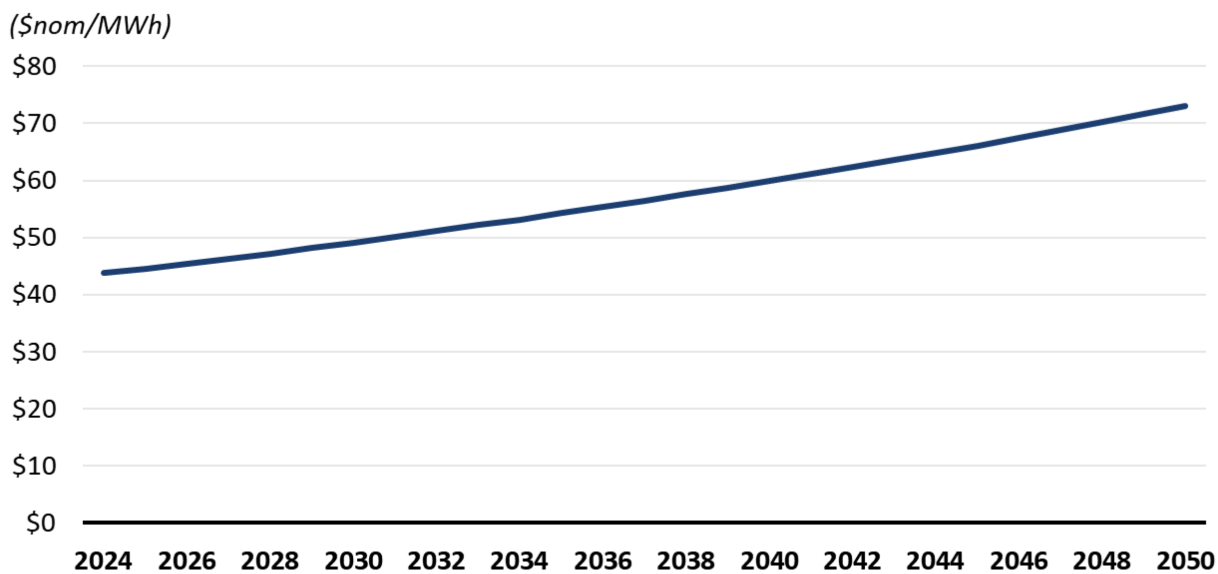
[61] 26 U.S. Code § 45U - Zero-emission nuclear power production credit

the nearest \$0.5/MWh, which results in step changes of \$2.5/MWh to the full PTC. Dollar values reflect the pre-tax value of the credit before accounting for a composite state and federal corporate tax rate. The PTC's mechanism for rounding inflation adjustments is not reflected in this analysis.

OPERATING COSTS

To develop the typical operating costs and ongoing capital expenses for a representative nuclear plant, we used the gross receipts method described in the 45U legislation to derive the revenue limit of the PTC. This measure captures the intent of the tax credit: supporting at-risk units which have higher avoidable costs than market revenues. Equation 2 can be rearranged and solved to find the measure of gross receipts such that the tax credit would be zero (extending this calculation throughout the analysis period). Figure 7 shows how the break-even gross receipts level increases over time as the PTC is adjusted for inflation (assumed to be 2%).

FIGURE 7: BREAK-EVEN GROSS RECEIPTS



Notes: Stepwise inflationary adjustment to the maximum PTC is not applied here when calculating the break-even gross receipts. Break-even gross receipts here are intended to represent the typical ongoing operating costs of a nuclear plant, and a regular stepwise adjustment would not meaningfully reflect how operating costs increase over time.