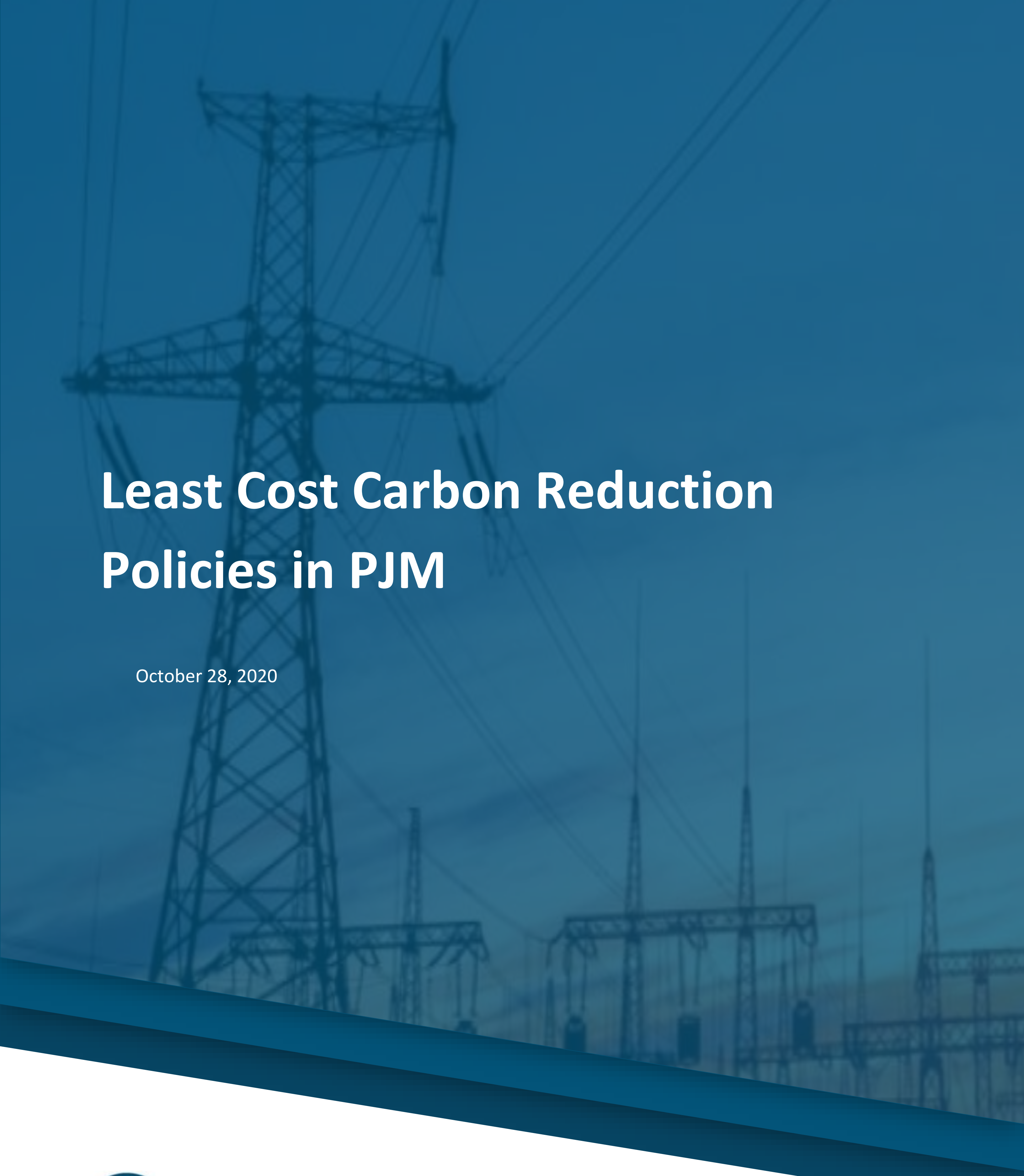

Least Cost Carbon Reduction Policies in PJM

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Energy+Environmental Economics

Least-Cost Carbon Reduction Policies in PJM

October 2020

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1 Executive Summary

In recent years, local authorities and utilities across North America have set increasingly ambitious targets for clean energy procurement that are based on a vision of grids with over 80% clean energy supply and major deployment of emerging technologies like offshore wind and battery storage. These policies are reshaping the grid and the incentives that govern both hour-to-hour power system operations and decade-to-decade investment decisions. The implications of these policies are important for grid operators across the continent, but especially significant for the Pennsylvania-Jersey-Maryland (PJM) Interconnection system, which is the largest power market in the U.S. and serves customers from Chicago to Atlantic City.

This study by Energy and Environmental Economics, Inc. (E3) examines a variety of alternative policy options to facilitate long-term decarbonization in the PJM region in a least-cost, least-regrets manner. Currently, the region is subject to a hodgepodge of state and local clean energy policies. Most, though not all, of these policies have been successful at increasing clean energy deployment and reducing carbon emissions for their jurisdictional utilities, but at an unnecessarily high cost. This study finds that there are alternative policies that would be more cost effective at reducing carbon emissions across the PJM system today; and, more importantly, that current policies do not scale well as clean energy targets become more ambitious. Policies that expand the set of choices for market participants to reduce carbon emissions, both geographically and with respect to qualifying technologies, are found to result in the most cost-effective emissions reductions; while conversely, policies that restrict technology or location choices are the least cost effective.

To quantify the fundamental system needs and associated costs and environmental impacts of different policy choices, we use E3's Renewable Energy Solutions Model (RESOLVE) to simulate PJM operations and capacity expansion under alternative policy scenarios. RESOLVE is a linear optimization model that minimizes total cost over a multi-decade time horizon, considering fixed costs associated with new investments in resources like wind and solar, as well as production costs to serve hourly forecasted loads.

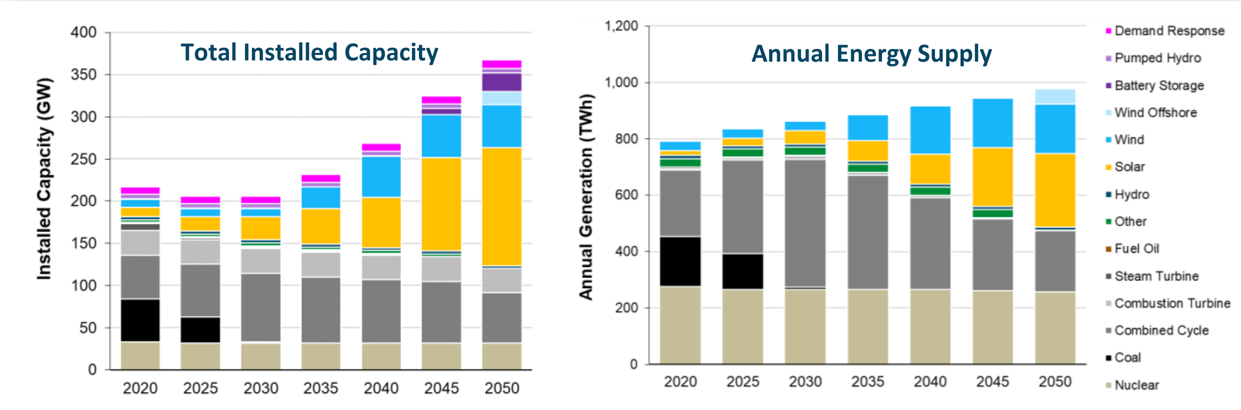
In this study, we use RESOLVE to test the implications of today's state policies versus alternative future policy scenarios from 2020 through 2050, comparing the implications of four different sets of energy policies:

- Business as Usual (BAU) scenarios that are representative of current policy;
- Renewables Portfolio Standard (RPS) policies that mandate increased renewable generation;
- Clean Energy Standard (CES) policies that credit any form of qualifying clean power; and
- Greenhouse Gas (GHG) Reduction policies that place a price on carbon through a cap-and-trade program.

For each policy scenario, E3 models the associated system resource needs, hourly operations, and associated costs and emissions over time.[1] Figure 1 depicts an example of model outputs for total installed resource capacity and annual energy generation by fuel type for a system targeting 80% GHG reductions by 2050.

[1] Costs modeled in RESOLVE include production costs (i.e., fuel, variable operations and maintenance costs), going-forward costs (i.e., fixed operations and maintenance costs, sustaining capital expenditures (capex), etc.), and costs of investment in new resources.

Figure 1. Installed Capacity and Annual Generation in a PJM System under 80% GHG Reduction by 2050 Goals



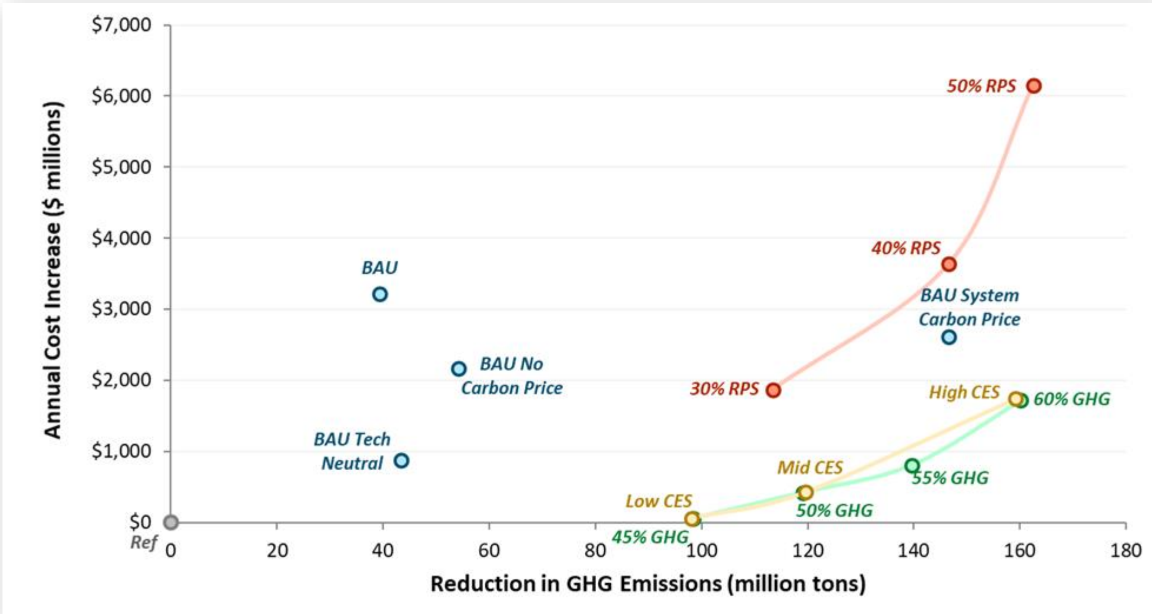
The following chart summarizes the key cost and greenhouse gas implications from each of our scenarios in 2030. Our study finds that the most cost-effective policies for reducing carbon emissions are those that directly target carbon emissions, either by placing a price on carbon or by placing a limit on electricity-sector carbon emissions. These policies are portrayed in green and labeled with "GHG" in Figure 2. A region-wide CES reduces emissions by mandating that a certain percentage of energy supply be sourced from qualifying clean energy resources. A CES policy can approach the effectiveness of direct carbon regulation if it distinguishes between fossil generators with different carbon intensities, such as generators that burn gas versus coal, though the program design and market outcomes will differ.

By contrast, a policy that focuses on a more limited set of solutions, such as an RPS, is found to be a significantly higher cost than a broad-based policy. Significant investment in renewable resources forms a key component of all scenarios, but a policy that focuses exclusively on renewable deployment does little to accelerate coal retirements, retain economic nuclear generation, or incentivize more energy efficiency.

The region's current carbon pricing policy, which covers generators in a subset of states within PJM, is shown to be counter-productive because it excludes many of the region's coal-fired generators; eliminating it would reduce both cost and carbon emissions relative to the BAU scenario. While sub-regional implementation of the Regional Greenhouse Gas Initiative (RGGI) is less effective than a comprehensive regional approach, by encouraging expansion to additional states, in particular those with significant amounts of coal generation, RGGI can become more effective. Extending this partial carbon pricing regime to the entire PJM system would add little cost compared to the current footprint but would reduce annual carbon emissions by nearly 100 MMT by 2030.

Finally, the suite of currently approved energy policies in the region, which include a series of targeted investments in and mandates for specific resources (i.e. state RPS programs), as well as partial carbon pricing through RGGI, is found to have significant costs but limited effectiveness in reducing carbon emissions. The aggregate impact of these policies is estimated to add $3 billion per year to electricity bills in the region by 2030, while reducing carbon emissions by only 40 million metric tons (MMT) relative to a policy-free "Reference Case." Much deeper emissions reductions could be achieved at a much lower cost with a more optimal carbon policy. For example, a GHG target of 50% below 2005 levels by 2030 would reduce carbon emissions by nearly 120 MMT versus the Reference Case at a cost of less than $500 million per year.

Figure 2. PJM System Costs and Emissions Savings in 2030 from Current and Alternative Policy Mechanisms



1.1.1 Key Findings

E3's modeling reveals many consistent trends across all policy scenarios, such as the need for large scales of renewable energy to achieve long-term policy goals. However, we find key differences in the cost-effectiveness and resource efficiency of different policy structures. We summarize our key findings as follows.

Key Finding #1: Policies that regulate carbon directly result in the lowest-cost emissions reductions.

These policies work by placing a price on carbon, either directly through a tax or fee or indirectly by constraining carbon emissions via a cap-and-trade system.

Finding 1a: Smart carbon policy can achieve significant emissions reductions at a very low cost in PJM.

For example, the PJM system can reduce emissions by 50%, or 200 MMT, from 2005 levels by 2030 at a minimal cost by increasing generation from the lowest-cost renewables and gas resources while retiring expensive, aging coal plants. This would require a carbon price as low as $10/ton. By contrast, existing state policies are projected to increase electricity bills by approximately $3 billion per year by 2030, while reducing emissions by only 30% relative to 2005 levels. Even without existing state policies, the PJM system would see a continued transition toward competitive clean energy in the near term as coal plants retire in favor of more economic gas generation and low-cost renewables that harness the collective diversity of PJM's energy resources, as seen in E3's policy-free Reference case scenario.

Finding 1b: Carbon pricing that does not apply to all generators in the PJM footprint has limited effectiveness due to the potential for resource shuffling.

The region's current carbon pricing mechanism, the RGGI, does not apply to the entire PJM footprint. Much of the PJM system's coal capacity is located in states that are not part of RGGI. The principal effect of this partial carbon pricing program, as modeled by E3, is reduced natural gas generation in states with carbon pricing and increased coal generation in states without carbon pricing. Eliminating this partial carbon pricing in PJM is shown to reduce carbon emissions by approximately 10 MMT, while saving consumers $1 billion annually.[2] At the same time, extending carbon pricing to all PJM states would reduce emissions by nearly 100 MMT in 2030, while reducing cost relative to a BAU policy scenario, demonstrating the effectiveness of system-wide carbon pricing.

However, system-wide carbon pricing would require either (1) all PJM states to join RGGI, or (2) a federal system of carbon pricing that covered the entire PJM footprint. Thus, while this study adds to the mountain of evidence that comprehensive carbon pricing is the most cost-effective policy mechanism for reducing emissions, it does not solve the jurisdictional dilemma of how it can be achieved within the United States' federal system of jurisdiction in the absence of federal action.

In addition to the findings above, carbon pricing offers a significant advantage that other policy scenarios examined do not: carbon accounting offers a common metric for broader, economy-wide decarbonization efforts, both in the PJM region and elsewhere. While not explicitly studied here, prior studies by E3 and others have shown that coordinated planning for carbon reductions across all sectors of the economy are needed to achieve long-term goals at least cost. Carbon pricing offers the unique ability to incentivize emissions reductions from both the power sector and other sectors of the economy – such as transportation, buildings, and agriculture – on a level playing field. A common carbon framework across these sectors may be increasingly important in the future as policymakers set more ambitious carbon reduction goals. Moreover, a U.S.-wide carbon pricing program would provide additional opportunities to seek out cost-effective emissions abatement opportunities from anywhere in the country.

Key Finding #2: A regionwide, technology-neutral Clean Energy Standard (CES) approaches the efficiency of a direct carbon policy in achieving low-cost emissions reductions in the power sector.

A regional CES would require that a certain percentage of energy supply come from qualifying clean energy resources located anywhere within the PJM footprint.

Finding 2a: Expanding the market's choices leads to lower-cost outcomes.

CES policies do not directly target carbon emissions; rather, they create incentives or mandates for the market to favor lower-emitting alternatives. CES policies that maximize choice for the marketplace lead to lower-cost outcomes. In addition to renewable generation, these choices might include:

+ Retention of existing economic nuclear plants. While a detailed evaluation of the cost of relicensing and continued operations of each of the 33 nuclear plants in PJM is beyond the scope of this study, E3 finds that there are potentially significant savings from retaining the region's most economically competitive nuclear plants.[3] A CES provides a technology-neutral mechanism for these plants to be compensated for their clean energy attributes, enabling them to compete on a level playing field with other qualifying resources to meet policy goals.

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[2] Modeling of this issue by PJM has yielded similar conclusions, wherein RGGI today produces a net *increase* in emissions from power generation in the PJM system. PJM is actively studying market enhancements to address this issue.

3 While highly unlikely, retiring all nuclear plants at the end of their current licenses significantly raises the price of achieving 80% carbon reductions versus alternative emissions-reduction approaches. Political decisions around the viability of nuclear plant life extensions is outside the scope of this report, but these may have a profound impact on the future costs to reduce carbon emissions.

- Switching from coal to natural gas generation. A CES policy that gives partial credit for coal-to-gas switching, with the credit calculated based on differences in emissions intensity, incentivizes generation from cleaner fossil resources.

- Advanced clean energy technology. New technologies such as small modular nuclear reactors (SMRs), fossil generation with carbon capture and sequestration (CCS), or hydrogen fuel could save nearly $100 million per year by 2050 under deep decarbonization policies or billions per year under 100% GHG-free targets based on technology cost forecasts from NREL[4] versus policies limited to technologies that are commercially available today.

Conversely, restricting choices is shown to increase the cost of achieving a given carbon target:

- Allowing only renewable resources to qualify (under a regionwide RPS policy) increases the cost of achieving 100+ MMT emissions reductions by over $1 billion per year. Restricting the choice of renewable generators through mandates and carveouts increases costs even further.

The large and diverse PJM footprint can be a significant aid in integrating large quantities of carbon-free resources. Overly prescriptive state policies unnecessarily increase costs to consumers because they do not allow market participants to take maximum advantage of the capabilities of the PJM system.

Finding 2b: A CES is more conducive to state policy drivers than carbon pricing.

Compared to carbon pricing, a CES regulates energy supply choices made by jurisdictional entities, which may be more conducive to state-by-state policymaking. A regional CES simply requires some of the PJM states to voluntarily agree to harmonize the definition of clean energy attributes to enable trading in a regional market. In this way, offshore wind in the Atlantic seaboard would count the same as solar or land-based wind in Illinois. Participation by multiple states would reduce costs relative to each state acting independently. A full regional CES offers similar emissions benefits to systemwide carbon pricing because both policies yield a similar grid evolution: coal generation phases out in favor of more economic gas and renewables, then renewables increasingly offset gas as the marginal generation resource thereafter.

While a regionwide CES would offer significant benefits compared to today's patchwork of policies, these advantages would be blunted under a state-by-state CES approach with restrictions on eligible resources. The key benefits of the CES is its ability to harness technological and geographic diversity to drive the least-cost outcomes for electricity customers.

Finding 2c: Market distortions created by CES policies would become more meaningful in the long run.

Because CES policies focus on accelerating the deployment of clean electricity generation, their impact on carbon emissions is only indirect. As a result, such policies create market distortions that, in the long run, may limit their effectiveness or raise their costs as a carbon abatement mechanism. For example:

- CES policies suppress wholesale energy prices and create the conditions for widespread negative prices in wholesale energy markets. Compliance under a CES policy is achieved by retiring a clean energy attribute produced by generating a megawatt-hour (MWh) of energy from a qualifying resource. Instead of raising the cost of operating carbon-emitting resources,

[4] Resource costs for nuclear SMRs and gas generators with CCS are based off the National Renewable Energy Laboratory (NREL) 2019 Annual Technology Baseline (ATB) and result in a 2050 LCOE of $63/MWh for advanced nuclear and $68/MWh for a gas generator with CCS technology in real 2018 dollars.

CES policies in effect reduce the cost of operating qualifying resources through the creation of the attribute, which has value in the compliance market. During hours when the system is saturated with clean energy and no additional clean energy can be absorbed, generators may be willing to pay buyers up to the attribute price to avoid having their generation be curtailed by the system operator. Our simulations show over 20% of hours with negative prices in 2050 in certain CES scenarios. This phenomenon is already being observed in energy markets in the Western Interconnection.

+ CES policies directly incentivize new clean generation, but do not provide price signals for conservation or energy efficiency. The price distortions from negative energy prices may even encourage wasteful consumption during hours with negative wholesale energy prices.
+ CES policies cannot directly be linked to clean energy policies in buildings, industry or transportation in the same way that carbon pricing can. Thus, their utility is limited to minimizing electricity-sector costs.

While CES policies appear to be a promising mechanism for linking policies among states seeking aggressive carbon reductions today, for the reasons described here, they might best be considered transitional policies that should eventually be replaced with a uniform, federal carbon regulatory policy.

Key Finding #3: Renewable resources play a significant role in decarbonizing the PJM system in all scenarios.

Renewable resources today constitute a low-cost, low-risk means for quickly achieving significant carbon reductions in the PJM system. Over 50 gigawatt (GW) of renewable resources are selected in our modeling to meet emissions reduction goals by 2030, and over 100 GW by 2050. However, other actions are needed beyond just increasing renewable production. A near-term strategy for renewable investment plus fuel-switching from coal to gas could reduce carbon emissions by up to 50% below 2005 levels at minimal cost.

Finding 3a: A renewables-only policy is significantly more costly than a broad-based CES.

As we have seen above, restricting clean energy investment to renewable generation increases the cost of achieving 100+ MMT emissions reductions by over $1 billion per year.

Finding 3b: Restricting access to some renewable resources significantly increases the cost of achieving carbon reductions.

High-quality renewable resources can be developed at a reasonable cost in many locations, but not everywhere on the PJM system. Restricting access to renewable resources can significantly increase costs.

+ Land-use considerations are likely to be an important constraint on renewable energy availability in the PJM region. Already, developers report difficulty finding suitable sites for development in many areas with good resources. The base case assumptions in our study allow solar to be developed on land equivalent to 4% of farmland in the PJM footprint, and wind to be developed on 4% of farmland and 2% of forestland. Restricting land availability by 50% relative to the base case would increase the costs of achieving an 80% GHG reduction target by $2.4 billion per year in 2050. Conversely, allowing unlimited renewable energy development wherever it is most valuable within the PJM footprint would reduce costs by nearly $3.5 billion per year in 2050 under the same policy.

Finding 3c: Offshore wind may play a significant role in meeting long-term clean energy needs but is more costly than onshore alternatives in PJM through the mid-to-late 2030s.

Offshore wind is a large potential source of renewable energy that may be less supply constrained than land-based resources in the long run. However, in the near-to-medium term, there appears to be significant savings from sourcing cheaper solar and onshore wind from more resource-rich parts of the PJM system. Offshore wind becomes part of the least-cost solution in the mid-to-late 2030s, depending on the availability of onshore resources and other alternatives. Higher load growth due to electrification may also accelerate the depletion of onshore resources, leading to earlier development of offshore wind. This suggests that policies related to offshore wind should be focused on creating an industry that is ready to scale up significantly over time, rather than maximizing deployments in the near term.

Key Finding #4: Current clean energy policies are costly and ineffective at reducing carbon emissions.

States in the PJM region have enacted a mix of clean energy policies, from direct mandates that procure certain resource types (e.g., Solar Renewable Energy Credits (SRECs) in New Jersey and offshore wind in Virginia) to subsidies that maintain existing resources (both nuclear and coal resources). This study estimates the cost and carbon savings of this suite of policies. The policies are found to increase electricity system costs by over $3 billion in 2030 relative to a reference case, while achieving only 40 MMT of carbon emissions. These policies are costly for several reasons:

+ They frequently require development in specific geographic areas, even if the resources in those areas are more costly than resources in other locations;
+ They apply carbon pricing to a limited subset of PJM—which hinders potential emissions reductions—as opposed to more comprehensive, and thus efficient, carbon pricing possible through RGGI expansion or a federal carbon policy as discussed above; and
+ They frequently target specific resource types or even specific generators, rather than enabling the market to select the least-cost resource mix.

To be fair, many current policies were not intended to be comprehensive electricity-sector carbon reduction policies, and carbon reductions are not the only policy objective for current measures. Nevertheless, a new policy regime will clearly be required to achieve deep carbon reductions at the lowest cost.

Key Finding #5: Firm capacity is needed to provide reliable electric load service at each level of decarbonization.

While this study does not offer a detailed evaluation of reliability needs under deep decarbonization for the PJM system, it is clear from this and other studies that firm capacity is needed to ensure adequate supplies of electricity during a broad range of weather conditions

Finding 5a: Retaining gas generation is a low-cost means of maintaining reliability on a deeply decarbonized system.

Across all scenarios, the study selects significant quantities of gas capacity to remain in place through 2050 to meet reliability needs while flexibly balancing renewable generation. While gas capacity additions vary by scenario, 50-90 GW of firm gas generation appears economic under most deep decarbonization policy pathways. Even in the most ambitious GHG reduction scenarios where nuclear and renewables serve 80% of energy, gas-fired generation is a cost-effective solution for meeting peak load and maintaining grid reliability by providing reserve capacity when needed. These resources are dispatched less and less over time as more zero-carbon generation sources are added to the system. Forcing these existing gas resources to retire adds significant cost but does little to reduce carbon emissions.

5b: Reaching decarbonization targets approaching 100% levels will be cost prohibitive without a source of clean firm generation, as costs otherwise increase exponentially beyond 80% reduction levels.

The average societal cost of 60%-80% GHG reduction policies in PJM appears to be less than $30/ton of carbon under coordinated regional policy efforts such as a systemwide CES or GHG policy. While this cost is lower than the RGGI cost containment caps and estimates of the social cost of carbon, the cost of further GHG reductions approaching 100% would rise exponentially if limited to today's fully commercialized technologies. For example, tightening 2050 emissions from an 80% GHG reduction to a 90% reduction would increase the marginal costs of policy compliance to around $150/ton. Moving from a 90% to 100% GHG reduction target would increase the cost of marginal GHG reductions to over $350/ton.

Reaching the endpoints of many "100%" goals being set today may require CCS, new nuclear generation, new sources of renewable biogas or hydrogen fuels, or other forms of clean fuel generation that, while technically achievable, are not commercially available today. Achieving absolute zero carbon emissions requires one or more of these resources to become available. Flexible, market-based policy mechanisms like carbon pricing will be best equipped to incentivize these technologies of the future on a level playing field, spread risk evenly among market participants, and avoid path-dependent incentive mechanisms.

2 Introduction

2.1 Clean Energy Policies in the PJM System and Purpose of Study

Today, the primary incentives driving the clean energy transition in PJM are state policies. States covered by PJM employ a wide array of policy mechanisms to support clean energy and reduce carbon emissions, including mandates for clean energy resources like solar and offshore wind, subsidies for existing zero-emission nuclear plants, and taxes on power plant emissions through the RGGI cap-and-trade program. State policies across the PJM system differ greatly in their degree of ambition, ranging from Kentucky's lack of climate goals to Virginia's target of 100% clean power by 2045.

As the largest power market in the United States, the PJM system is well positioned to facilitate a cost-effective transition towards a lower-carbon grid. The PJM system covers a diverse footprint of states, utilities, consumers, and existing and emerging energy resources from Illinois to New Jersey. This collective diversity offers significant cost savings through the pooling of power market supply and demand. The beneficiary is the end consumer. By enabling competition at a regional level, the PJM market ensures the lowest-cost energy resources serve the bulk of the grid's needs.

The purpose of this study is to examine the efficacy of current state policies in enabling an affordable transition to a cleaner energy supply in the PJM market. As states across PJM have made increasingly large, long-term commitments to clean energy, the financial stakes for these commitments have grown substantially in scale. More effective implementation of the 2050 goals of 100% clean energy in Virginia and New Jersey, for example, could save consumers hundreds of millions of dollars per year by 2030 versus more prescriptive policies that limit potential outcomes. In this study, E3 calculates the costs and benefits of existing state policies and potential regional policy approaches to reduce GHG emissions from the PJM grid. E3's analysis utilizes its RESOLVE representation of the PJM system. E3's modeling efforts and specific findings are described in the remainder of this report.

2.2 Report Contents

The remainder of this report describes E3's modeling of the PJM system under various future policy scenarios. The report first summarizes the PJM grid and the types of state policies used to incentivize clean energy, such as renewable portfolio standards (RPS) and carbon pricing. Section 3 describes in detail how the current and future PJM system is represented in E3's RESOLVE model and defines the different policy scenarios that E3 has modeled. The detailed results of E3's modeling are then presented in Section 4. Lastly, E3 discusses key conclusions and remaining questions on the policy future of the PJM grid in Section 5.

3 Modeling Approach and Key Assumptions

3.1 Study Region: the PJM System

3.1.1 PJM Background

The PJM Interconnection is a regional transmission organization (RTO) in the United States. An RTO serves as a neutral and independent party that coordinates electric power generation and transmission and operates a competitive wholesale electricity market to ensure the reliability and efficiency of the bulk electric power system in its territory.

As the largest RTO in the United States, PJM manages more than 84,000 miles of transmission lines and serves 65 million customers. As of 2019, the annual electricity consumption in PJM was approximately 787 terawatt-hour (TWh), with a peak demand of approximately 166 GW. Current energy demand in PJM is met primarily by natural gas (37% of annual energy), nuclear (34% of annual energy), and coal (24% of annual energy).[5]

Since its formation in 1927, PJM has expanded to 22 member utilities, with the latest joining in 2018. PJM's continued growth provides wider opportunities for trading and access to additional conventional and renewable resources, driving increased cost savings for market participants.

Figure 3 shows a brief timeline of PJM's history and member utilities.[6] PJM's service territory spans all or parts of 13 states, including Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia; and the District of Columbia.[7] These states and federal district represent a diverse range of energy users, energy resources, and political goals for the power sector. Collectively, the PJM system encompasses a region with a variety of low-cost fuels, competitive generators, and local renewable resources. This study examines the role of these resources and the wider PJM system in helping constituent states achieve their respective policy goals.

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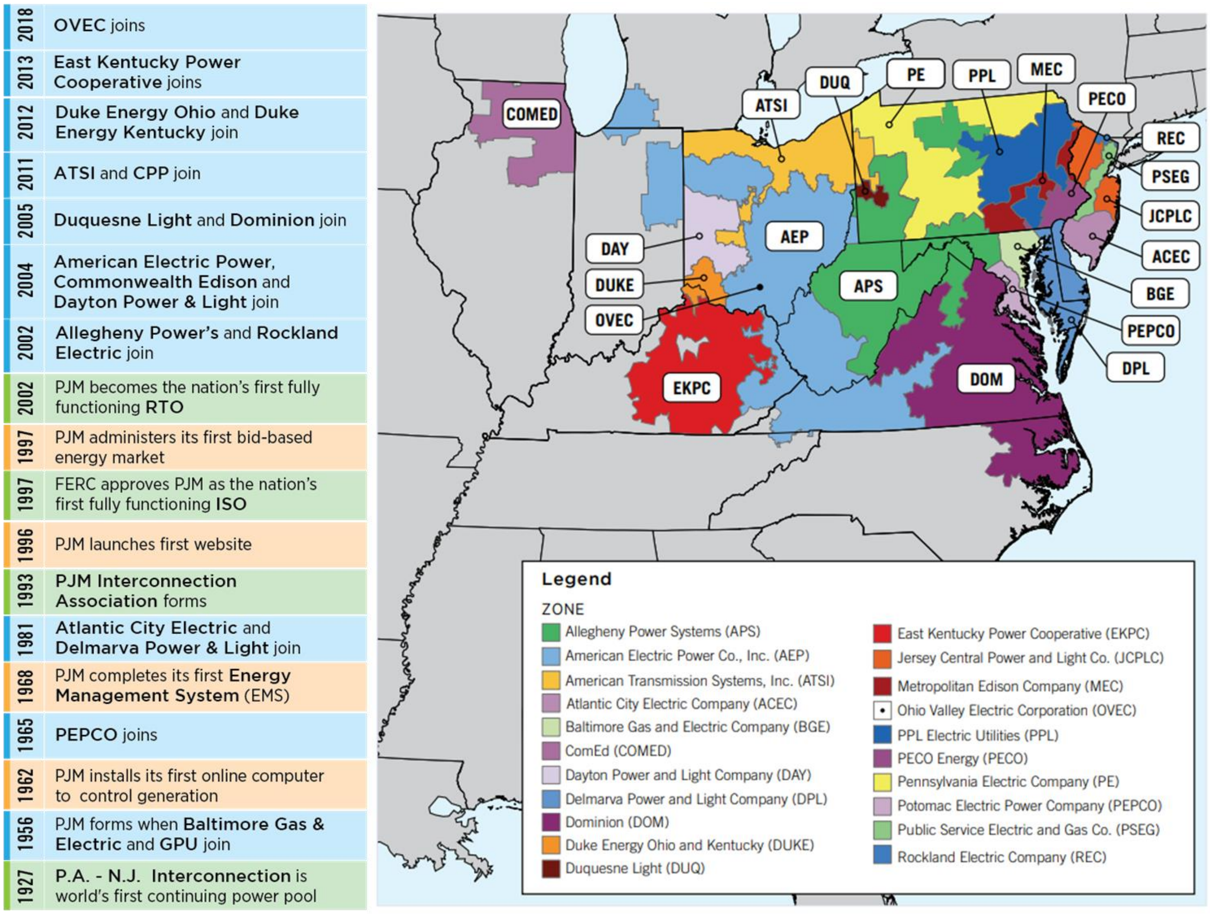
[5] 2019 PJM Annual Report, https://www.pjm.com/-/media/about-pjm/newsroom/annual-reports/2019-annual-report.ashx?la=en.

[6] Formally referred to in the PJM context as "zones," which are "areas within the PJM Control Area, as defined in the PJM Reliability Assurance Agreement." See definition in the PJM Load Forecast Report: https://www.pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx?la=en. In this study, "zones" is used to refer to RESOLVE zones defined for modeling purposes unless otherwise specified.

[7] PJM website, "Who We Are," https://www.pjm.com/about-pjm/who-we-are.aspx.

Figure 3. PJM Territory and Brief History[8]



3.2 Policy Mechanisms for Greenhouse Gas Emissions Reductions

3.2.1 Overview of Decarbonization Policy Mechanisms

Though there are many different ways to incentivize a greener energy supply, policymakers have typically relied on two options: 1) subsidize or mandate cleaner energy sources, or 2) tax or ban dirtier energy sources. Today, states' policy mechanisms in PJM employ both of these approaches, with the former being most common. For example, RPS and CES programs are used to support lower-emission resources, while Greenhouse Gas (GHG) Reduction Targets disincentivize higher-emission resources. These three policy frameworks differ in what they regulate and how, but ultimately are an intended transition to a cleaner, long-term energy supply in order to reduce CO_2 emissions. More specifically:

+ Renewable Portfolio Standards (RPSs) are set to ensure that a specific percentage of annual electricity, often retail sales, is derived from renewable resources. States can also choose which electricity providers or utilities must comply with an RPS. An RPS may apply to all utilities or in other instances may only apply to investor-

[8] Both graphics are from the PJM website. Timeline of PJM: PJM History, https://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx. PJM territory map: Maps – Transmission Zones, https://www.pjm.com/library/~/media/about-pjm/pjm-zones.ashx.

owned utilities (IOUs). The progress of RPS policies is most often tracked through the issuing of RECs, which are provided to entities for every MWh of RPS-eligible electricity that is generated. States develop their own RPS targets and can dictate what qualifies as an alternative energy resource. If a state wants to develop a particular resource faster than others, it will tend to include what is known as a "carveout," which sets aside a resource with a specific target within the RPS. Traditional RPS-eligible resources include solar, wind, tidal, wave, and certain hydro resources; however, with states dictating what qualifies for RPS, the types of resources can diverge from the conventional notion of renewable energy. Resources that have been included in a few state RPS policies range from biomass to waste coal. An RPS that includes alternative non-renewable resources may be better labeled as a Clean Energy Standard.

+ Clean Energy Standards (CES) are a more inclusive version of RPS policies. A CES policy allows a broader range of qualifying resources, which facilitates a more cost-effective reduction of greenhouse gas emissions. For example, under a CES, resources with lower emissions rates may be able to reduce total system GHG emissions at a lower cost than renewables. Though the definition of what qualifies for CES eligibility can vary by state, low- or zero-emitting technologies such as nuclear, biomass, waste-to-energy, and natural gas are some of the resources that may fall under the "clean" umbrella. In a CES policy framework, Clean Energy Credits (CECs) and partial credits based on emissions intensity are issued much like RECs. Partial credits allow carbon emitting technologies to contribute to compliance with CES policy targets based on emissions intensity relative to a specified benchmark. This enables lower-emission resources to provide GHG emissions reductions where possible, while also potentially incentivizing higher emitting resources to seek refurbishments or upgrades to units to ultimately reduce emissions intensity. Clean energy credit mechanisms have historically been employed differently from RECs and have been used to support existing resources such as nuclear power plants via Zero-Emission Credit (ZEC) subsidies. However, more comprehensive CEC trading may allow broader competition across different clean energy resources in the future. To our knowledge, no state has employed such a program that credits renewables, nuclear, and other zero-emission sources equivalently.

+ Greenhouse Gas Reduction Targets (GHG targets) offer a wider policy scope to reduce emissions than CES and RPS targets. This type of target does not cater to specific technologies and instead focuses on the overall reduction of emissions by any means. For example, in addition to new zero-emissions technologies like renewables, switching to cleaner fuels (e.g., from coal to gas) can help achieve these goals. These policies are usually achieved through one of two mechanisms: 1) carbon tax/pricing; or 2) carbon cap and trade. Carbon pricing involves setting the price of carbon at a specific level that all participants who produce carbon emissions must pay. The cap-and-trade method sets a cap on carbon emissions and allows participants to trade emissions credits with one another to meet the carbon reduction target. Under this program, entities that have a harder time reducing carbon emissions and are short of credits will be able to buy emissions credits from another entities that are oversupplied with emissions credits, thereby creating a market price for carbon as opposed to setting a fixed price via the carbon pricing method. Emissions credits will tend to be allocated toward high-emitting power plants such as coal and gas that require credits to cover their emissions.

These policies range from indirectly reducing GHG emissions (e.g., RPS and CES, whereby subsidized clean resources offset presumably dirtier resources) to directly reducing them (e.g., carbon pricing, which makes higher-emitting resources more costly and less competitive). E3's modeling has frequently shown that more direct incentives are more effective on a total cost basis. Indirect incentives such as RPS policies are more costly due to the restrictions on which resources are eligible to produce RECs. RPS policies also do not differentiate between renewable resources that generate energy in the most emissions-intensive vs. cleanest hours of the day. All resources are equally incentivized, regardless of GHG reduction impact. Similarly, RPS carveouts for certain technologies in specific locations often deviate from the optimal resource mix to cost-effectively reduce emissions, resulting in higher system costs. Direct incentives, such as GHG reduction policies, offer a less costly mechanism for achieving deep power-sector decarbonization because all resources can be valued for their low- or zero-carbon characteristics.

3.2.2 State Policies in the PJM System

States within the PJM territory use a wide range of policies to promote renewable energy, reduce GHG emissions, and support specific technologies and plants, such as several nuclear and coal-fired generators. Certain states do not currently have any RPS or CES policies. Table 1 shows current RPS and CES standards across PJM states, as well as selected "carveout" requirements for specific technologies. Resources that qualify for RPS credits vary from state to state. Ohio RPS targets were not considered in this study due to the recent House Bill 6 (HB 6) legislation that repeals Ohio's former RPS target. HB 6 will reduce Ohio's 2026 target from 12.5% to 8.5% and then eliminate the RPS entirely after 2026.[9]

Table 1. State Energy Standards[10]

State	RPS/CES Target Year	RPS/CES Target (% of sales)	Solar Carveout (% of sales)	Onshore Wind Carveout (% of sales)	Offshore Wind Carveout (GW)
District of Columbia	2032	100%	5.5%		
Delaware	2026	25%	3.5%		
Illinois	2026	25%	1.5%	1.0%	
Maryland11	2030	50%	14.5%		1.2 GW
Michigan	2021	15%			
North Carolina	2021	13%			
New Jersey	2030	50%	2.21%		7.5 GW
Pennsylvania	2021	8%	0.5%		
Virginia12	2050	100%			5.2 GW

Most states within PJM feature an RPS target and many states support nuclear via separate, more narrowly defined ZEC programs. Of states with RPS policies, there is a split between moderate, shorter-term targets and larger, longer-term targets. States such as Delaware, Illinois, Michigan, North Carolina, and Pennsylvania have RPS goals that range from 8% to 25% for the target years between 2021 and 2026. At one end, Pennsylvania has a goal of 8% by 2021 and Delaware and Illinois have a 25% goal by 2026. States with more ambitious longer-term targets include Maryland, New Jersey, the District of Columbia (DC), and most recently Virginia. Maryland and New Jersey both have RPS targets of 50% by 2030, while DC is targeting 100% RPS by 2032 and Virginia has a goal of 100% clean energy by 2050.

[9] Proposals to repeal Ohio's HB 6 are ongoing but were not considered within the scope of this study.

[10] A few states, including the states of Michigan and Pennsylvania, allow non-renewable alternative resource to contribute to their RPS. DSIRE, https://www.dsireusa.org/

[11] Maryland Senate Bill 516, http://mgaleg.maryland.gov/2019RS/bills/sb/sb0516f.pdf

[12] This is a CES; however, it is being modeled as an RPS, Virginia Acts of Assembly Session 2020, Chapter 1193, https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+CHAP1193+pdf

Many states have carveouts requiring specific resources to make up their RPS targets. For example, Maryland and New Jersey both have portions of their RPS targets that must be filled by solar and offshore wind. Illinois must have a certain amount of its RPS target fulfilled by solar and wind. Though some states require a small amount of in-state resources to contribute towards the RPS or CES targets, a larger portion of clean energy can be procured from out-of-state by simply purchasing RECs from resources in other states.

Two states in PJM have passed economy-wide GHG emissions targets: New Jersey (80% reduction from 2006 baseline by 2050) and Maryland (40% reduction from 2006 baseline by 2030). Other states within the PJM territory have issued emissions targets through Executive Directives, as seen in Table 2.

Table 2. State Emissions Targets Issued Through Executive Directives

State	Emissions Target	Target in MMT CO_2e
PA	80% by 2050 (2005 baseline)	294.85
DE	30% by 2030 (2008 baseline)	16.14
MI	26% by 2025 (2005 baseline)	-
IL	60% by 2050 (1990 baseline)	231
NC	40% by 2025 (2025 baseline)	152.08
DC	100% by 2050 (2006 baseline)	10.10

These GHG reduction goals would only need a portion to come from the electricity industry. It is to be expected that these targets will be non-binding and will be eclipsed by coal retirement and RPS goals. With this in mind, state-specific GHG targets were not modeled in this study, as RPS policies will tend to drive compliance above and beyond these targets. In addition to state-specific, economy-wide GHG goals, there is also a carbon cap-and-trade market on power-sector emissions in the Northeastern United States called the Regional Greenhouse Gas Initiative (RGGI). A few of the states participating in RGGI are in the PJM footprint; however, not all states within PJM footprint participate in RGGI.

Several states in PJM provide direct subsidies to nuclear and coal plants outside of existing RPS and GHG policies. Illinois and New Jersey offer credits through a ZEC program to nuclear resources, which are specified by each state according to certain criteria. Ohio offers subsidies to certain nuclear and coal plants through HB 6, which is the same legislation that eliminated the previous RPS goals.

These numerous policies will have implications as to how the PJM market performs currently and how it will change in the future. States across the PJM service territory will likely continue to enact new legislation, modify existing legislation, or roll back legislation, given the diverse ideologies surrounding these types of policies from state to state. This study explores the effects these fragmented policies and potential future policies will have on the PJM system.

3.3 Scenarios and Sensitivities

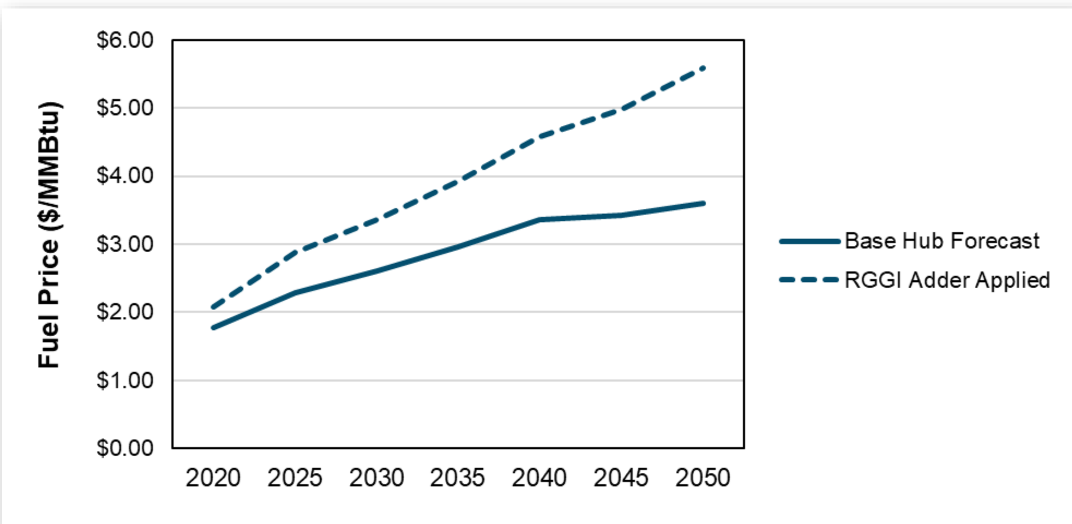
The policy scenarios and sensitivities modeled in this study were designed to represent and test potential policy approaches for reducing the carbon intensity of the PJM system. The many flavors of decarbonization policy currently enacted across PJM will bring differing implications for market participants in both the near term and long term. The existing policy landscape within PJM features a fragmented collection of state and utility goals that collectively incentivize (or disincentivize) GHG reductions across various interrelated jurisdictions. This lack of a coordinated policy regime creates risk of cost shifts, loopholes, and unintended consequences, which are investigated in the BAU set of scenarios. Additional alternative policy scenarios defined by E3 aim to explore PJM-wide strategies for decarbonization, which avoid the unintended consequences of the existing state-by-state framework. While policy change presents certain challenges, this report illustrates the value of a collective effort to reduce system carbon emissions and the different strategies to achieve those reductions.

3.3.1 Scenario Definitions

In this study, E3 sought to model both current state policies and alternative policy pathways for PJM. Current state policies, including partial carbon pricing representative of RGGI and existing RPS and CES standards with their respective renewable carveouts, are captured in the BAU scenario. Alternative policy scenarios, such as broader PJM-wide RPS, CES, and GHG policies were also modeled for comparison. Descriptions of each of the policies modeled in this study are discussed in turn.

Within RESOLVE, carbon prices are modeled as an adder to fuel prices in the applicable states. The $/ton adder used is an average of the RGGI price cap and floor.[13] These values are translated into $/million British Thermal Units (MMBtu), using separate emissions rates for gas and coal. Because RGGI only applies to generators in certain states, only some fuel hub prices have the adders applied. All else being equal, this drives higher fuel prices in RGGI states in the BAU scenario.

Figure 4. TRZ6_Non-NY Gas Price Forecast with and without RGGI Adder Applied

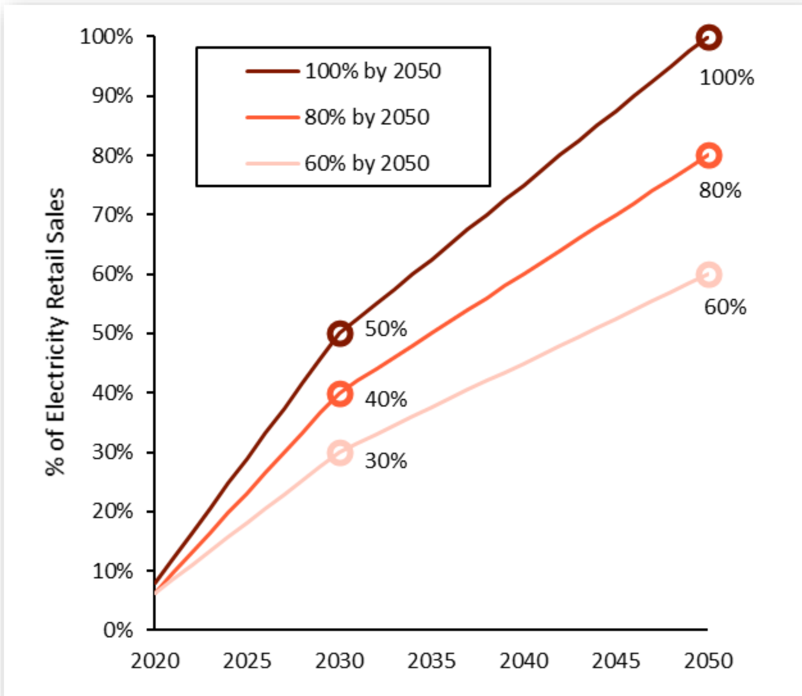


The BAU scenarios modeled in RESOLVE include individual state RPS and CES policies on the books today. The applicable RPS goals were first translated into an amount of retail energy sales for each state, based on the Energy Information Administration (EIA) retail sales data for relevant utilities within the PJM territory. Since, to a large degree, states can purchase RECs to contribute towards their RPS or CES policy goals from resources that are not necessarily within their own state boundaries, these state targets were aggregated and modeled on a PJM-wide basis. This aggregated PJM-wide target represents the cumulative targets of all states relative to PJM total retail sales. The BAU scenarios include topline RPS and CES targets as well as sub-targets for specific technology carveouts. Carveouts include in-state solar and onshore wind as well as recent offshore wind carveouts for certain states.

[13] RGGI cap and floor prices are established through the Emissions Containment Reserve (ECR) and Cost Containment Reserve (CCR) through Model Rule 2017 https://www.rggi.org/sites/default/files/Uploads/Design-Archive/Model-Rule/2017-Program-Review-Update/2017_Model_Rule_revised.pdf

E3's alternative Regional RPS scenarios are represented in RESOLVE by creating an increasing minimum renewable energy requirement, defined as a percentage of total PJM retail sales. Existing zero-emission resources such as landfill gas and hydro are considered RPS eligible within E3's model; however, it is assumed for the purposes of this policy study that any additional resources procured for RPS targets will be chosen from solar, onshore wind, or offshore wind. Biogas is considered a clean resource that can help lower GHG emissions but is not considered an RPS-eligible resource. E3 models a spectrum of regional RPS requirements over time that reflects differing levels of policy ambition. The trajectories of these policies begin at current levels of renewable energy penetration and increase to varying degrees ranging from 60% RPS to 100% RPS by 2050.

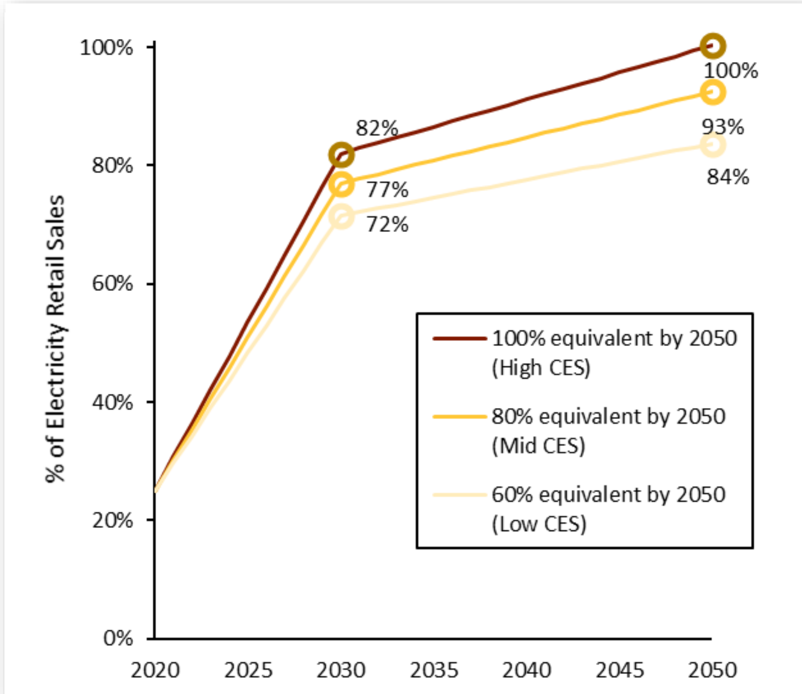
Figure 5. RPS Trajectories Used in RESOLVE Modeling



Regional CES are modeled within RESOLVE as a middle ground between a REC/ZEC policy and a full carbon price, wherein nuclear generation fully counts towards annual clean energy requirements and partial clean energy credits are awarded to resources based on emissions intensity. For example, energy produced by nuclear energy receives full clean credit, gas-fired energy receives partial clean credit, and coal emissions receive zero credit. By incentivizing resources based on their relative level of emissions, this policy structure enables more direct incentives to reduce emissions relative to a simpler binary clean/non-clean CES credit system. CES targets, as shown in Figure 6, are modeled with three policy trajectories[14] defined in terms of the equivalent percent GHG reduction scenario.

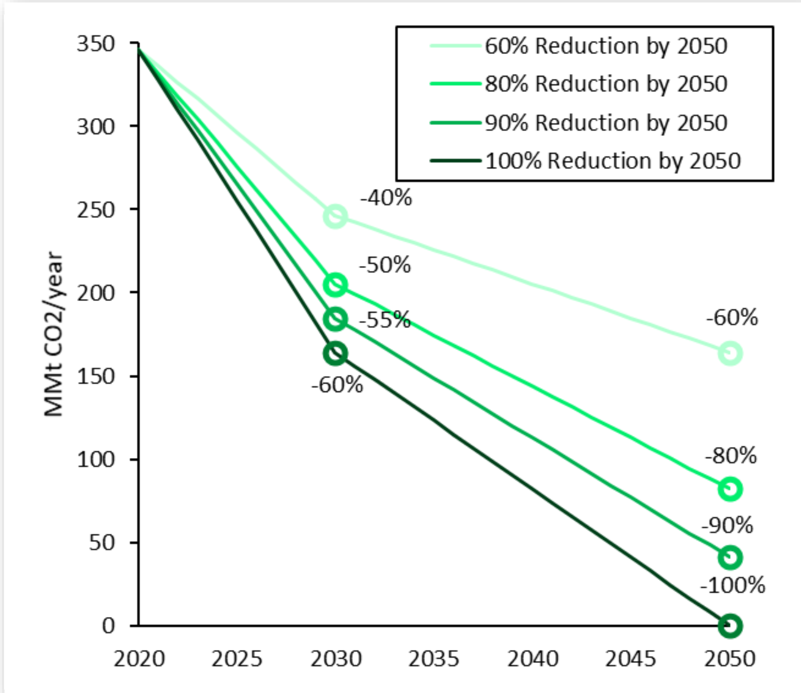
[14] The CES case trajectories were designed to achieve similar GHG reductions by 2050 in the equivalent GHG reduction trajectories in Figure 7; however, it does not follow the exact same trajectory.

Figure 6. CES Trajectories Used in RESOLVE Modeling Based on Equivalent GHG Reductions



Lastly, the Regional GHG Reduction policy scenarios model a range of GHG emissions targets that decline over time, representative of either a cap-and-trade program or progressively increasing carbon tax. The respective GHG targets in each scenario were set relative to a baseline of 2005 CO_2 emissions levels of 411 million metric tons carbon dioxide equivalent ($MMtCO_2$). PJM's 2005 GHG levels were developed using 2005 Federal Energy Regulatory Commission (FERC) data for MWh generation, along with the average CO_2 emission per MWh in 2005 issued by PJM. The trajectories for the modeled GHG Reduction scenarios range from 60% to 80% to 100% emissions reductions from 2005 levels by 2050, as depicted in Figure 7. Under the GHG policy scenarios, gas plants that switch to biogas (representative of other zero-emission fuels) after 2040 contribute an additional option for reducing overall GHG emissions on top of the renewable and nuclear resources that receive credit in the RPS and CES scenarios.

Figure 7. GHG Reduction Trajectories Used in RESOLVE Modeling



All policy scenarios in Figure 5 and Figure 7 feature kinks in their policy target trajectories, as opposed to straight lines to better reflect the reality of clean energy adoption. The sharper slopes through 2030 reflect the lower relative cost of achieving early policy compliance, as seen in E3's modeling. Early progress towards clean energy goals is expected to be cheaper due to the availability of the best untapped, low-cost renewables and the relatively lower cost of operating a grid with lower renewable penetration. The flatter slope in later years represents a more gradual deployment of clean resources as land becomes more restricted, interconnection takes longer, and grid integration of renewables becomes more costly, likely outweighing forecasted cost declines of renewable technologies.[15] In short, the change in slope of the policy targets post-2030 is intended to smooth the relative costs of these policies more evenly over time while better representing an achievable trajectory for compliance.

3.3.2 Scenario Summary

Collectively, the scenarios modeled can be categorized into four sets – Business-as-Usual (BAU) scenarios, Renewable Portfolio Standard (RPS) scenarios, Clean Energy Standard (CES) scenarios, and Greenhouse Gas Reduction (GHG) scenarios. The BAU set encapsulates current policies and minor adjustments to current policies. The other sets explore PJM-wide alternatives to the BAU scenarios through different levels of achievement within each policy category. All current policies (including state RPS targets, resource carveouts, subsidies, and partial carbon pricing) were removed from these alternative cases to show how these policies differ from each other without the limits and biases that stem from current policies. The full set of core scenarios is shown in Table 3 and each is described in detail further below.

[15] Detailed assumptions regarding technology cost forecasts can be found within Appendix A under Section 6.1.4 PJM System Future Resource Options.

Table 3. Core Sets of Scenarios Modeled in This Study

Modeling Scenario Group		RGGI Carbon Price Active	Existing Carveouts & Subsidies	Resource Policy Goal Eligibility	Policy Levels of Achievement by 2050
Reference		X	X	X	X
BAU	***(Current)***	**✓ (current and planned states)**	✓	Solar, Wind, Offshore Wind + grandfathered	**Existing State RPS Policy Levels**
	System Carbon Price	**✓ (all states)**	✓		
	No Carbon Price	**X**	✓		
	Tech Neutral	**X**	**X**		
RPS		**X**	**X**	Solar, Wind, Offshore Wind + grandfathered	• **60%** • **80%** • **100%**
CES		**X**	**X**	Solar, Wind, Offshore Wind, Nuclear + grandfathered (*full credit*) Gas (*partial credit*)	• **Low** • **Mid** • **High**
GHG reduction		**X**	**X**	**X**	• **60%** • **80%** • **90%** • **100%**

Reference Scenario. The reference case is a counterfactual case that creates a baseline with which to compare all other scenarios. In this case, no policy constraints are applied, and RESOLVE will solve for the least-cost future resource mix to serve load.

Business-as-Usual (BAU) Scenarios. The BAU cases best represent the current state of the world with existing policies in place. Existing state policies, including renewable portfolio goals, specific resource carveouts, the RGGI, and nuclear and coal subsidies are included in the base BAU case. One applies RGGI PJM-wide, while another removes RGGI altogether. The final scenario removes RGGI in addition to specific resource carveouts.

Renewable Portfolio Standards (RPS) Scenarios: The three RPS policy scenarios set RPS goals that follow the trajectories illustrated in Figure 5. RPS eligibility for new resources, which was defined in an earlier section of the report, includes only to solar or wind; however, the eligibility of existing resources is extended to landfill gas and hydro, in addition to solar and wind resources.

Clean Energy Standards (CES) Scenarios: The CES policy scenarios follow trajectories shown in Figure 6 and are designed to achieve emissions reduction trajectories similar to the GHG scenarios. The CES scenarios are an extension of RPS policies and a step closer towards full carbon pricing, where nuclear resources are also eligible to contribute towards reaching the CES goals, gas generation receive partial credit, and coal generation receives no credit.

Greenhouse Gas (GHG) Reduction Scenarios: The four GHG reduction scenarios reduce PJM CO_2 emissions by a percentage relative to 2005 amounts. The cases have GHG emissions trajectories that follow the trends in Figure 7. All non-emitting resources as well as biogas can help contribute to lowering GHG emissions within these scenarios.

3.3.3 Sensitivities

In addition to the suite of policy scenarios modeled, a few sensitivities were developed using a selection of these runs. These sensitivities were based on assumptions focused on resource availability; namely, the availability of land for renewable development and the availability of other carbon-free resources. Table 4 shows the set of sensitivities considered and the associated core scenario(s) used to study each sensitivity.

Table 4. Set of Sensitivities Modeled in This Study

Modeling Sensitivity	Base Scenario(s) Tested
Land Use Constraints (constrained & unconstrained)	***80% GHG***
New Firm, Carbon-Free Energy (nuclear SMR, 90% capture CCS)	***80% GHG*** ***100% GHG***

Impact of Land Use Constraints on Renewable Development: Sensitivities were run for the 80% GHG reduction case to model the effects of the land-constraint assumption used. In one set, the NREL Regional Energy Deployment System (ReEDS) technical potentials as limits for solar and onshore wind builds were used (unconstrained); and in another, the resource potentials used in the base case were halved (constrained).

Long-Term Demand for Firm, Carbon-Free Energy: Additional sensitivities allowed for new firm, carbon-free technologies (new nuclear SMR and gas with 90% CCS) to be built. This sensitivity was run for the 80% and 100% GHG reduction cases.

4 Results

The core results from E3's modeled policy scenarios are presented in two different ways: 1) comparing findings across different classes of policy scenarios, and 2) comparing findings within a single class of policy applied at different levels. The first highlights the key differences between these types of policies given a "similar" level of policy stringency. For example, we compare the implications of an 80% RPS policy to an 80% GHG policy. The second dives deeper into each policy category and explores the implications of various levels of achievement. We then present the set of model sensitivities for further detail.

4.1 Scenario Modeling Overview

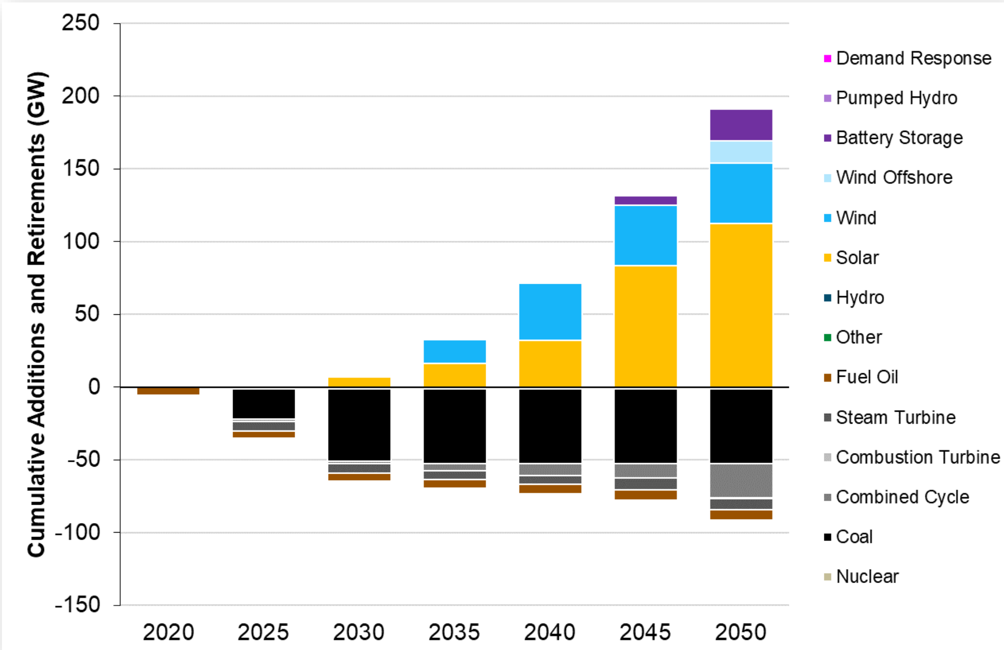
Each policy scenario was modeled in detail from 2020 through 2050 in five-year increments. RESOLVE identifies the least-cost power system over time to meet policy constraints and dispatch the system to reliably serve load across representative days for each model year. Altering policies and levels of policy achievement will change RESOLVE's investment, retirement, and dispatch decisions, resulting in different annual costs and emissions levels. Some of these trends are depicted in the example model outputs below.

4.1.1 80% GHG Scenario Example

While E3 has labeled policy scenarios by their respective 2050 target, each scenario requires intermediate progress towards this goal over time. In the example below, we show modeling results for a PJM system targeting and achieving a goal of 80% GHG reductions by 2050. Typical RESOLVE model outputs and trends are described herein using this scenario as an example.

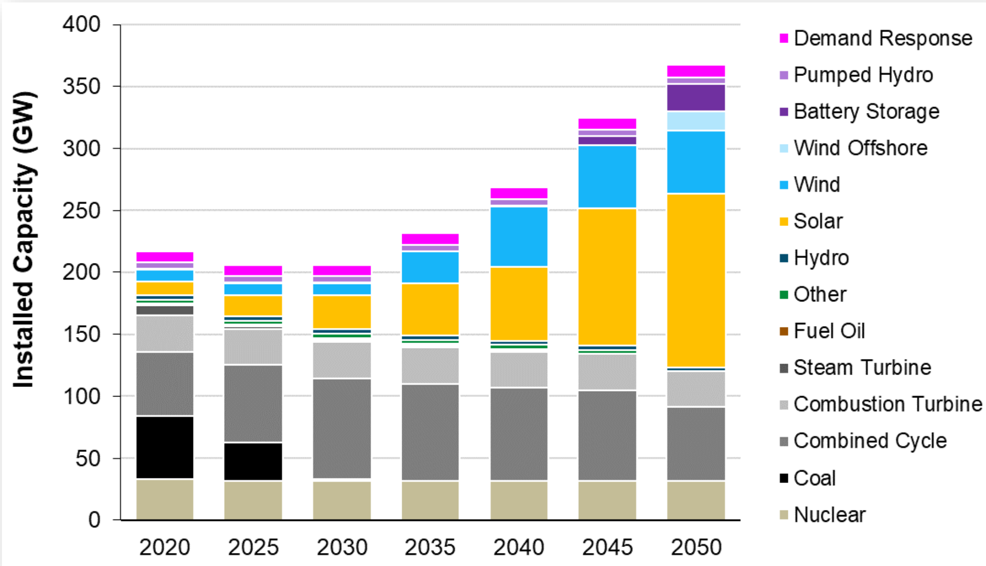
Often one of the simplest explanatory outputs from RESOLVE is a summary of resource additions and retirements across years, shown in Figure 8. 2020 represents the system today and no new resource decisions are allowed, as near-term additions or retirements are already captured in the model. Starting in 2025, the model can opt to add new resources or retire existing capacity to meet policy and reliability requirements at least cost. Most cases modeled in this study show a trend of near-term retirements because the PJM system is long on capacity (current Planning Reserve Margin, or PRM, exceeds the target needed for reliability) and would be less costly to operate if certain plants were shut down, as RESOLVE incurs the going-forward cost of all resources present on the system. As seen below, the most expensive coal capacity is typically retired first. However, in other cases, expensive nuclear capacity is retired as well. The GHG (and CES) scenarios modeled in this study typically show minimal nuclear retirements, because nuclear generation helps meet the policy goal. In the later model years (post-2030), when the GHG target gets more stringent, cheaper wind and solar are built first, followed by storage and offshore wind. As these resources are integrated on the system, less thermal capacity is needed, and a sizable amount of gas capacity is retired in 2050. Different policies will drive different investment and retirement decisions, which is a focal point of this study and highlighted in the next section.

Figure 8. Cumulative Nameplate Capacity Additions and Retirements for 80% GHG Case across All Modeled Years



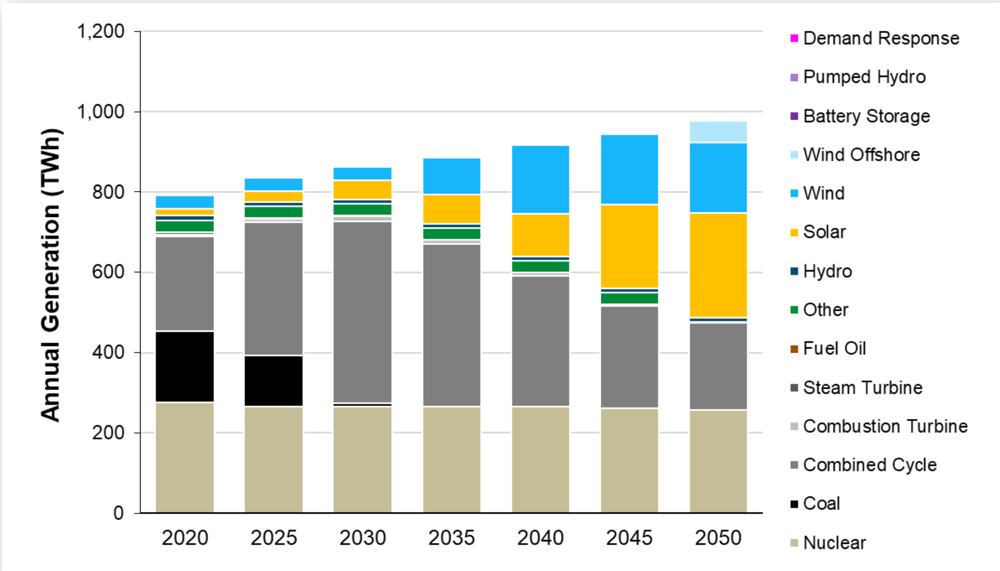
The resource additions and retirements above can be added to PJM's current portfolio of existing and planned resources to show the total installed capacity across the model years. As detailed in Figure 9, the PJM resource mix of today is primarily comprised of thermal resources – namely, gas, coal, and nuclear. Only a fraction of the installed capacity is made up of renewable capacity. In the near term, the total installed capacity is reduced, as RESOLVE retires underutilized resources to reduce system costs and capacity surplus conditions. In the long term, RESOLVE keeps much of the remaining thermal generation capacity online to maintain reliability and balance the grid as more renewables are added. By 2050, additional thermal resources are retired as new battery storage serves an increasing share of system capacity needs. This general theme of near-term retirements and longer-term renewable capacity investment holds true across all scenario results.

Figure 9. Installed Nameplate Capacity for the 80% GHG Case across All Modeled Years



Annual generation by resource type, as depicted in Figure 10, offers a slightly different perspective than the two figures above. Shifting trends in resource capacity are also visible in this figure, such as the reduction in coal generation and increase in renewable energy over time. However, shifting from installed capacity to annual generation highlights the difference in annual energy output per megawatt (or "capacity factor," a measure of utilization) from different resource types. For example, even though a significant amount of renewable nameplate capacity is on the system (well over 60% of system capacity in 2050), lower capacity factors of renewables result in a much lower share of annual energy (around or under 50%). Nuclear power, on the other hand, supplies an outsized share of energy versus its installed capacity due to its consistent "base load" power output around the clock. One overarching trend across all scenarios is that flexible thermal resources such as gas plants, tend to decrease as a share of energy supply over time while maintaining their share of system capacity. In effect, RESOLVE shows gas generation increasingly displaced by renewables over time but maintains gas capacity to ensure reliability requirements are met and thermal generation can ramp up to serve periods of low renewable energy supply.

Figure 10. Annual Generation for the 80% GHG Case across All Modeled Years



E3 has modeled each policy case at the full resolution shown above for the 80% GHG example. However, in the following results summaries, E3 has focused primarily on the 2030 (near term) and 2050 (long term) snapshot years for ease of comparison. Many of the trends in the 80% GHG scenario apply across all scenarios, thus the results section instead highlights key differences between scenario findings. Additional model outputs, such as total annual emissions and system costs, will also be discussed in detail as key metrics for comparing policy performance.

4.2 Trends Across Different Policy Scenarios

Each policy modeled incentivizes different strategies for achieving decarbonization. Each strategy and level of achievement will have a significant impact on how different the future PJM system will operate both in the near and long term. This section shows near-term (2030) and long-term (2050) results across scenarios with similar levels of policy achievement. The scenarios are listed below:

+ Reference Scenario: Used as a counterfactual case to compare against
+ Business-as-Usual (BAU): Includes existing set of policies, such as state RPS goals, partial carbon pricing, and resource subsidies
+ 80% RPS by 2050: Alternative policy scenario where solar, wind, offshore wind, and grandfathered existing RPS resources can be used to achieve goal
+ Mid CES: Alternative policy scenario where nuclear can also count towards the goal and gas is given partial credit
+ 80% GHG reduction by 2050: Alternative policy scenario where total GHGs in 2050 must be less than 80% of 2005 levels

The BAU case is much different than the alternative policy cases but was included to show how different the BAU trajectory is compared to today. Also, it is important to note that the alternative policy cases are similar in the sense that they achieve a significant level of decarbonization, but none have the exact same annual emissions trajectory. The core differences between these scenarios included are the installed capacities of each resource type (Portfolios), how much energy each resource group generates and the corresponding emissions (Generation and Emissions), and the system costs, including new investments and operational costs (Total System Costs).

4.2.1 Portfolios

The different policies drive variations in resource builds across scenarios, as well as across snapshot years. In all scenarios, resources are built and retired to meet future loads and reliability targets. The Reference case represents the most economical way to meet those constraints without any policies influencing what resources should be built. As different policies are layered on, some resources will be preferred to meet both policy goals and system constraints.

The BAU scenario shows a different resource portfolio than the Reference case, stemming from three policies that are active within the BAU case but are not applicable in the Reference case. These policies include partial carbon pricing representative of RGGI, state RPS targets, and state ZEC programs and similar resource-specific mandates. Partial carbon pricing allows some coal units to generate more if gas generation within carbon pricing states becomes too expensive because of the carbon adder. Therefore, the BAU case sees more coal online in 2030 compared to the other scenarios. Furthermore, the BAU case keeps larger amounts of nuclear generation online via subsidies called ZECs, whereas the Reference case retires some nuclear capacity. The renewable mix is slightly different between the Reference and BAU cases due to current state RPS policies only being implemented within the BAU scenario. The Reference case builds some economic onshore wind and solar resources; however, the BAU case builds more of these same resources due to RPS targets and adds offshore wind because of carveouts for this technology.

The differences across the RPS, CES, and GHG reduction scenarios in 2030 are most notable through the retention of nuclear capacity in the Mid CES and 80% GHG reduction scenarios. These scenarios value the GHG-free attribute of nuclear; while in the 80% RPS case, nuclear does not receive additional credit for the zero-carbon power it produces. Instead, larger amounts of solar and wind are built to meet the RPS target. The GHG scenario and the CES scenario use the same strategy to meet targets by phasing out almost the entire coal fleet and investing in some renewables.

Figure 11. Cross Comparison of PJM-Wide Installed Capacity by Resource Type in 2030[16]

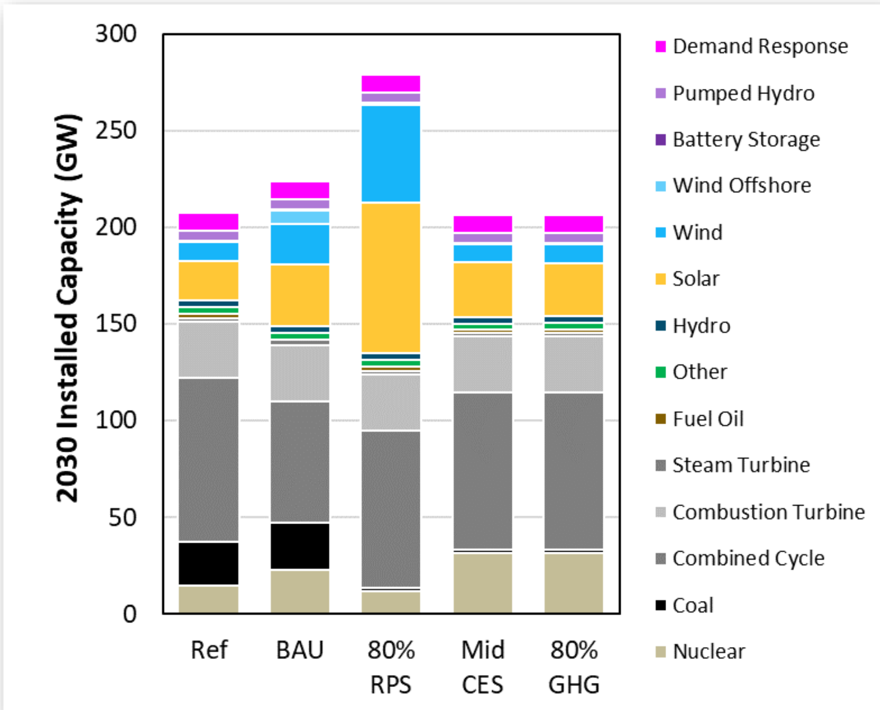
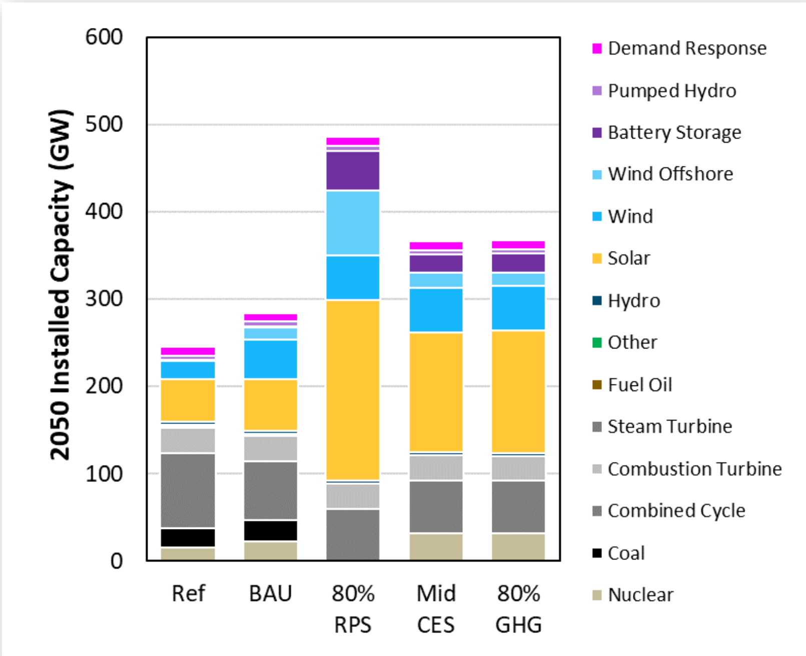


Figure 12 shows portfolios in 2050 across scenarios and highlights much of the same trends seen in 2030. Similar portfolio differences between the Reference case and BAU case can be seen, along with similar but expanded trends across the RPS, CES, and GHG scenarios. The core differences between 2050 and 2030 for the alternative policy scenarios are primarily an increase in renewable and storage capacity, full elimination of coal capacity, as well as the elimination of nuclear capacity in the RPS case. Additional solar and offshore wind are developed in 2050, as all onshore wind is fully developed. Battery storage is built in 2050 to help provide energy during times of low renewable output when gas cannot fully cover the deficit between supply and demand. Overall, the alternative policy scenarios' renewable installed capacities dwarf those from the BAU and Reference case. It is worth noting that the CES and GHG portfolios again are nearly identical which shows how differences in policy design can still achieve similar results if all resources are put on the same playing field.

[16] While policy scenarios are labeled based on 2050 targets (e.g., "80% RPS" describes an 80% by 2050 goal), this chart represents lower levels of policy achievement aligned with intermediate 2030 goals.

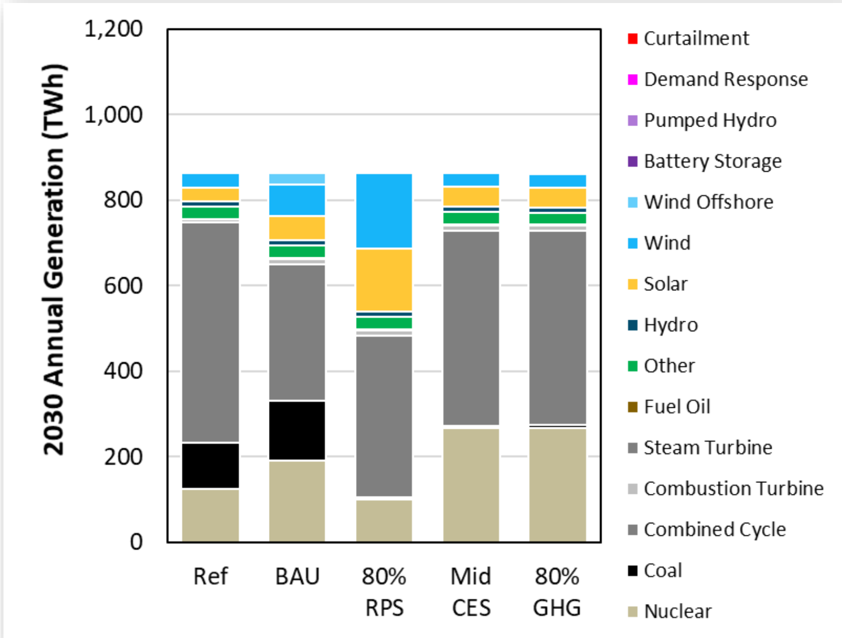
Figure 12. Cross Comparison of PJM-Wide Installed Capacity by Resource Type in 2050



4.2.2 Generation and Emissions

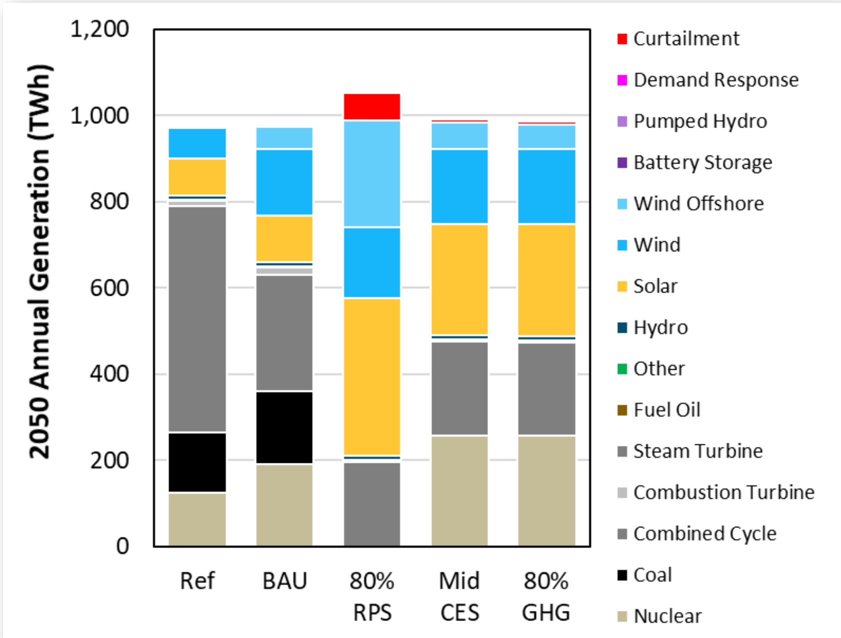
The generation mix in 2030 differs significantly across all scenarios, following the trends reflected in the portfolios. In the BAU case, there is much more coal generation and much less gas generation than any other case. This is caused by the RGGI carbon price. State-specific ZEC programs also drive more nuclear generation in the BAU case than the Reference case. Across the alternative policy cases, gas generation still makes up a significant share of annual energy with slightly less gas use in the RPS case as the renewables push lower thermal generation across the board. Coal generation is nearly eliminated while nuclear plays a crucial role in the CES and GHG reduction cases to meet policy goals.

Figure 13. Cross Comparison of PJM-Wide Generation by Resource Type in 2030



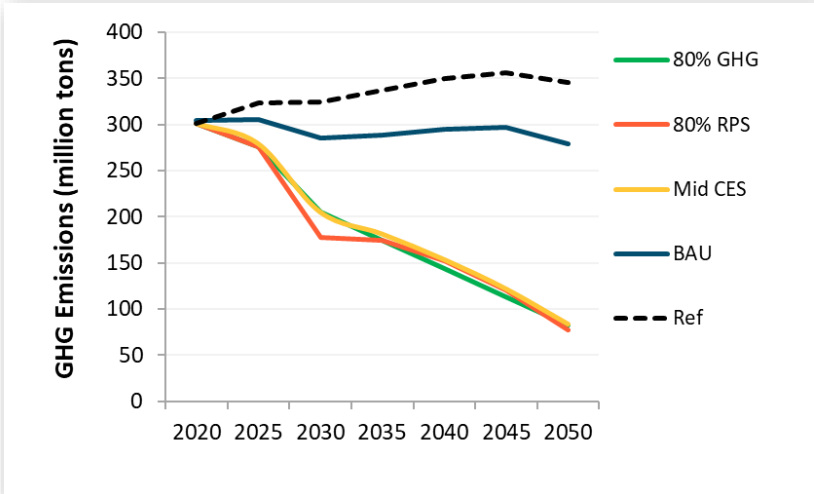
Trends seen in 2030 are exacerbated in 2050. The BAU case and Reference case are the only scenarios with any coal left. Gas generation is similar across the BAU and alternative policy cases, indicating the importance of firm, dispatchable generation on a highly decarbonized system. The RPS case sees a significant amount of curtailment, despite over 50 GW of storage capacity on the system. This is expected, as overbuilding storage capacity to soak up all renewable overgeneration is often more costly than allowing some curtailment. With so much renewable capacity on the system, the nuclear fleet is not needed, leaving gas as the core resource providing firm capacity. The CES and GHG reduction cases look the same with coal phased out and a combination of renewable buildout and nuclear fleet utilization used to achieve the policy goals.

Figure 14. Cross Comparison of PJM-Wide Generation by Resource Type in 2050



The differences in portfolios and generation lead to stark differences in GHG emissions between the BAU case and the alternative policy cases. The BAU scenario has an emissions trajectory slightly lower than the Reference case, while the alternative policy cases achieve significant and similar levels of GHG reductions in the long term, despite different strategies for achieving those reductions. Coal generation is the main driver of the carbon emissions, as the BAU and Reference scenarios retain coal generation through 2050 and the alternative policy scenarios eliminate it. In 2030, the CES and GHG cases have higher emissions than the RPS case because RPS-driven renewables replace more gas generation, but by 2050 similar levels of emissions are achieved.

Figure 15. Cross Comparison of Annual GHG Emissions



4.2.3 Hourly Price Trends and Total System Costs

Observing wholesale energy prices on representative days across years provides insight as to how the different policies change future system operations. As more variable resources are integrated, there will be sustained low-price hours when solar and wind output is high, as well as frequent peak prices when renewable output is low and dispatchable units must ramp up to meet demand. In California, large solar capacity drives the "duck curve" price trend, where prices are high in the mornings and evenings with depressed mid-day prices. On PJM's system, some days the "duck curve" trend can be seen, but often different patterns arise because of a more even mix of solar and wind. Figure 16 and Figure 17 show an example set of summer and winter days in 2030.

Figure 16. Example of a Representative Summer Day in 2030

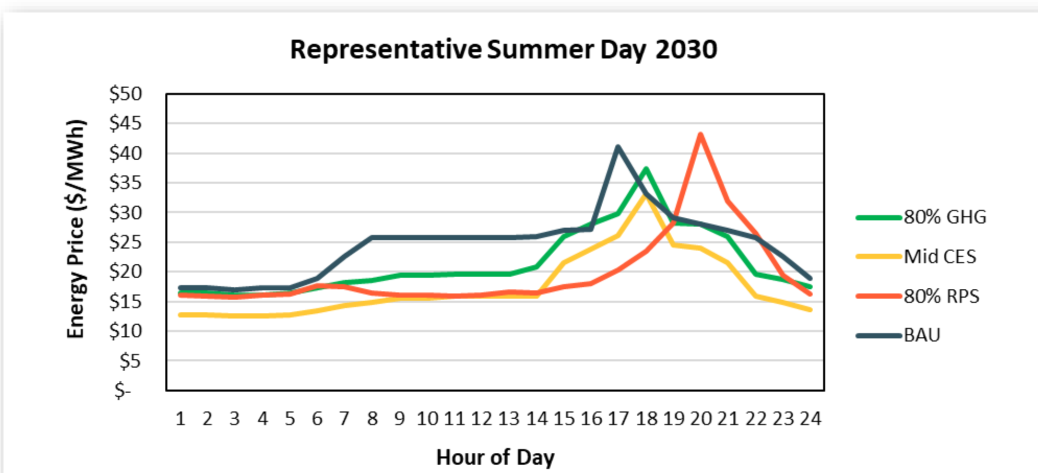
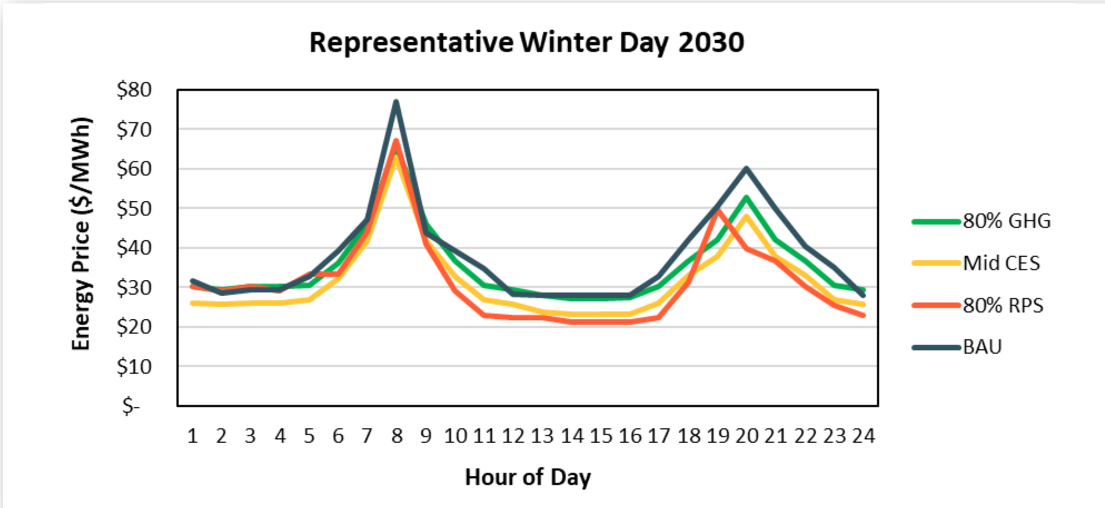


Figure 17. Example of a Representative Winter Day in 2030



Comparing trends between days is more noticeable than the trends between scenarios on a given day; however, the slight differences in system energy prices in RESOLVE (i.e., marginal costs of generation) do represent key differences in policy. The BAU case has the least amount of renewable energy capacity on the system, so the prices are the highest across scenarios; while the RPS case, with the most renewables, tends to have the lowest prices each day. The CES and GHG cases typically fall in between, with the CES case often having lower prices. While the CES and RPS policies yield lower energy prices than the GHG cases, this does not necessarily translate to lower system costs, as the CES and RPS policies require other out-of-market compensation in the form of REC or ZEC payments to incentivize qualifying sources of energy. When accounting for these out-of-market payments, total system costs under RPS policies appear higher, despite lower average energy prices.

Annual system costs vary across scenarios while producing clear trends across years. Figure 18 provides a high-level overview of cost trends for the core scenarios, though these costs cannot be compared directly without considering additional tradeoffs across scenarios. For example, the BAU case is more expensive in the near term, driven by fragmented decarbonization policies; but is similar in cost to the CES and GHG scenarios in the long term, despite much higher levels of emissions.

Table 5 and Table 6 provide a high-level comparison of costs and emissions across scenarios for 2030 and 2050, respectively.

Figure 18. Cross Comparison of Annual System Costs

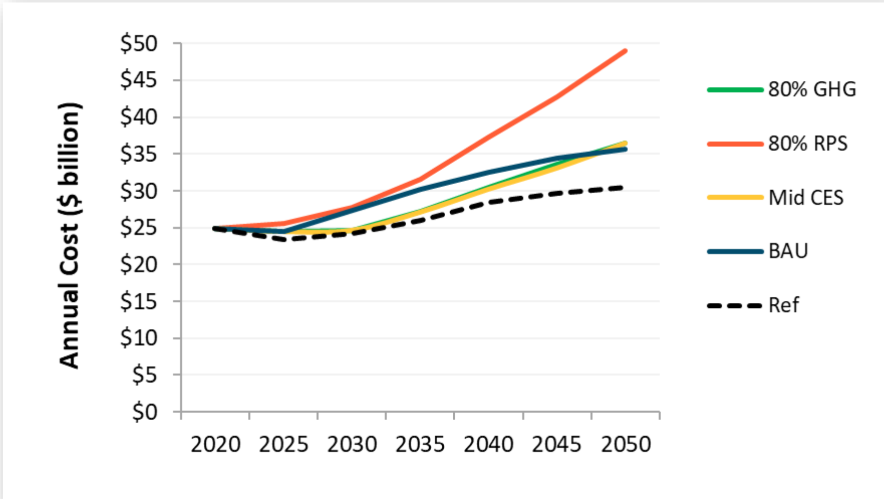


Table 5. Generation Costs and Emissions Metrics by Scenario in 2030

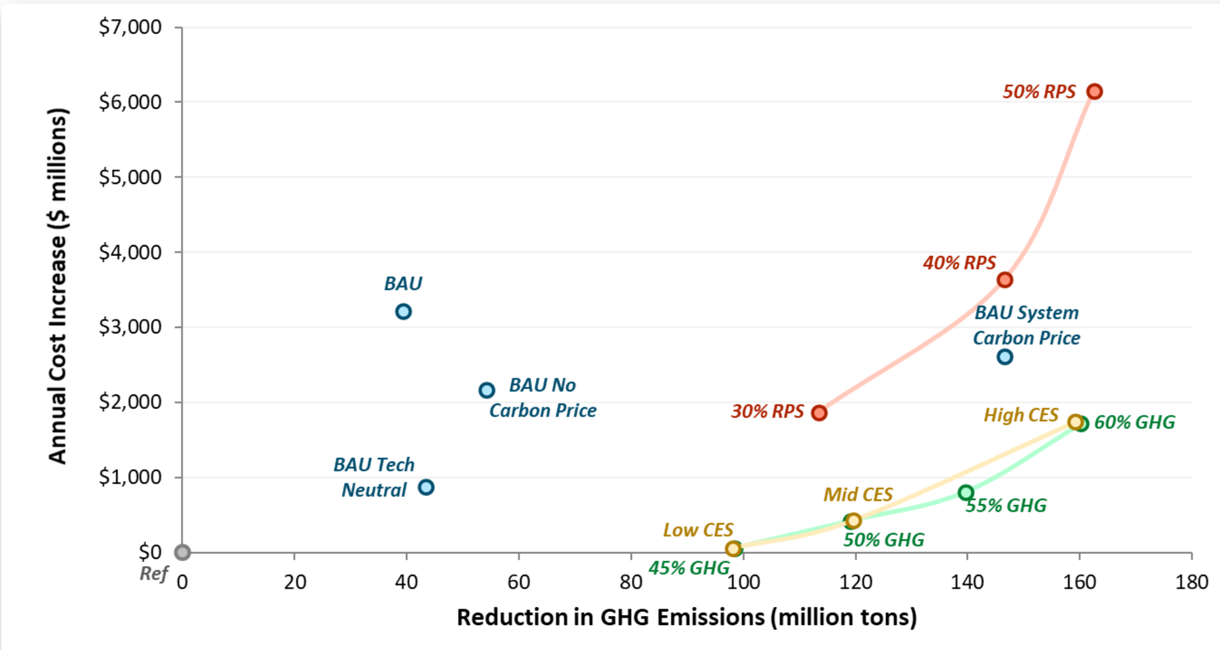
Scenario	Annual Cost of Generation ($ billion)	Incremental Cost ($ billion)	Annual GHG Emissions (million metric tons)	Avg Cost per Ton GHG Reduction ($/ton)	Carbon-Free Energy (%)
Reference	$24	-	324	-	23%
BAU	$27	$3.2	285	$81.8	42%
80% RPS	$28	$3.6	178	$24.8	50%
Mid CES	$25	$0.4	205	$3.6	41%
80% GHG	$25	$0.4	205	$3.6	41%

Table 6. Generation Costs and Emissions Metrics by Scenario in 2050

Scenario	Annual Cost of Generation ($ billion)	Incremental Cost ($ billion)	Annual GHG Emissions (million metric tons)	Avg Cost per Ton GHG Reduction ($/ton)	Carbon-Free Energy (%)
Reference	$31	-	346	-	30%
BAU	$36	$5.1	279	$76.8	53%
80% RPS	$49	$18.6	77	$68.9	81%
Mid CES	$37	$6.0	83	$22.6	78%
80% GHG	$37	$6.0	82	$22.7	78%

Figure 19 and Figure 20 provide a look into policy trends within a snapshot year and also across years. In 2030, most BAU cases have higher annual costs and higher emissions relative to other policies. Only when carbon pricing is applied throughout PJM does the BAU emissions level come close to other policies (detailed in Section 4.3.1); however, the cost is still higher than the GHG and CES scenarios, due to presence of other resource-specific carveouts outside the RGGI GHG policy. The different energy policies each show similar cost trends, with exponential cost increases as policy targets become more stringent in the future. RPS policies are able to generate the same amount of emissions reductions as the CES and GHG policies; however, they are significantly more expensive on an annual basis. Altogether, regionally-coordinated, technology-neutral GHG reduction policies or CES policies are the least-cost method for achieving deep decarbonization.

Figure 19. Cost of GHG Abatement across All Scenarios Modeled in 2030



In 2050, much of the same trends persist. The BAU annual costs and emissions levels stay relatively constant, while other energy policies become increasingly expensive with higher targets. The CES policy trajectories align with the GHG policy trajectories because the strategies to achieve these two policies overlap, resulting in similar resource mixes, and therefore similar costs. Figure 20 also highlights that in 2050 60% emissions reductions are possible at costs less than the current BAU trend, implying that significant GHG reductions are possible with the implementation of a coordinated PJM-wide GHG reduction policy. This may come at no cost to the customers, compared to the current non-coordinate policies across states within PJM, provided the current policy status for the states within PJM remains the same until 2050.

Figure 20. Cost of GHG Abatement across All Scenarios Modeled in 2050

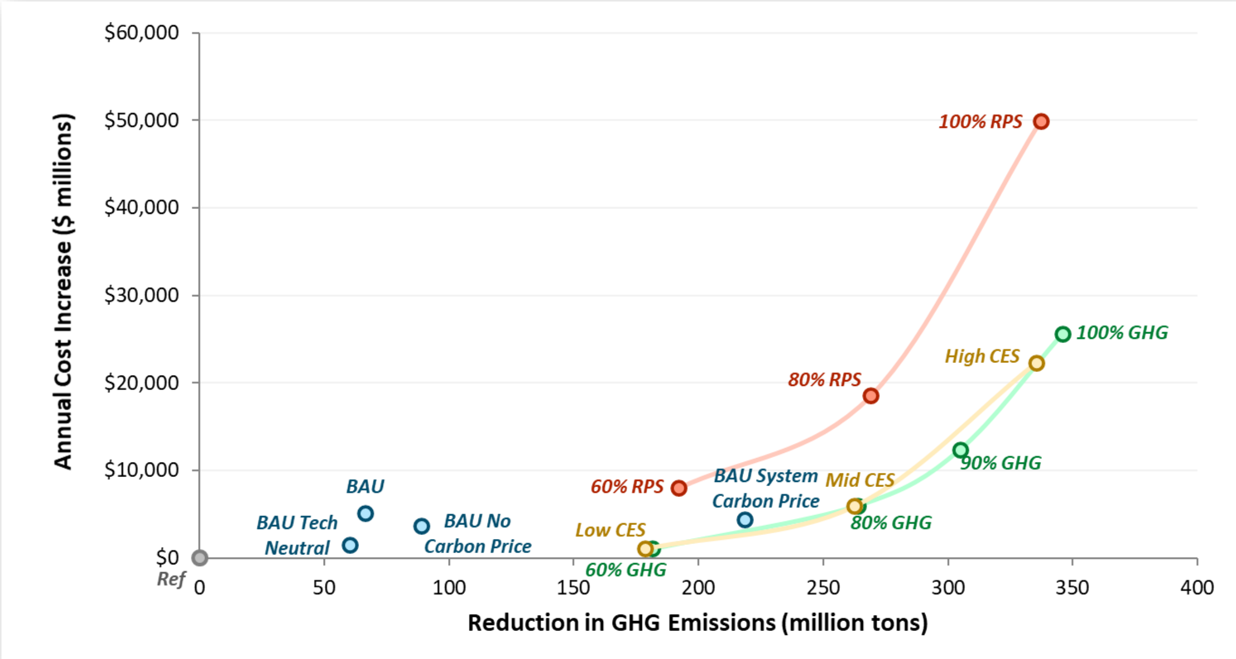
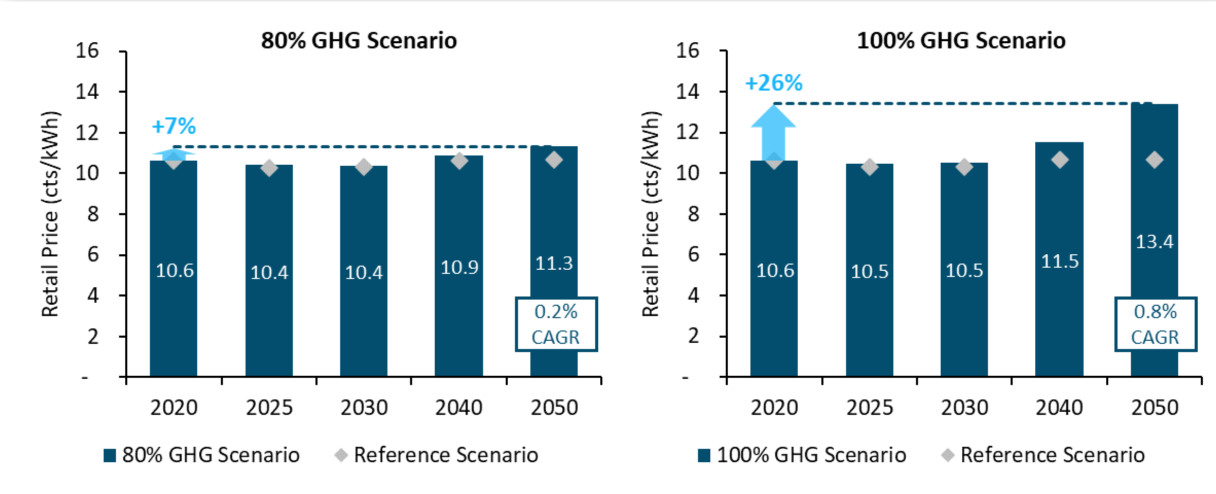


Figure 21 illustrates the impact of GHG reduction policies from the rate payer's perspective, specifically for the 80% and 100% GHG scenarios relative to the Reference scenario. In the short term, there is little to no change to retail electricity rates within a given scenario as early years involve cost-effective methods in meeting climate targets; however, as deeper levels of decarbonization are needed to meet the longer-term GHG targets, the incremental costs associated with meeting these goals increase significantly. These system cost increases in later years translate to a moderate impact on retail rates. Overall, the 80% GHG scenario sees a 7% increase in retail rates between 2020 and 2050, while a more stringent 100% GHG target shows a 26% increase in retail rates over the 2020 to 2050 time period. Rate impacts are calculated based on today's average bundled retail rates in PJM, including transmission and distribution charges, plus changes in average system cost from 2020 onward, as modeled in RESOLVE. These rate impacts do not account for any future changes in costs associated with the delivery of retail energy.

Figure 21. Retail Electricity Rate in 80% GHG and 100% GHG Scenarios (Real 2018 Dollars)



4.3 Scenario Details

Now that the core differences between types of policies have been established, this section investigates trends within each policy set. Here, slight tweaks to the BAU scenario are applied to show the impact of individual policies that exist today; while in the alternative policy sets (RPS, CES, and GHG reduction), various levels of policy achievement are tested. Each subsection is designed around the scenario set instead of key result, as organized in the previous section, but those key results are still detailed.

4.3.1 Business-as-Usual (BAU) Scenarios

The BAU scenario represents the current state of PJM with existing policies intact, which include RGGI, state RPS targets, and resource-specific subsidies. Other BAU scenarios in the set either expand or roll back portions of existing policy to capture the effects of each. One policy that was altered was RGGI. In the BAU System Carbon Price scenario, RGGI was applied across all of PJM while in the BAU No Carbon Price scenario, RGGI was removed entirely.[17] The last scenario of the set, BAU Tech Neutral, removes the resource-specific subsidies and carveouts in addition to RGGI. This represents a scenario where only top-line state RPS targets drive decarbonization over the PJM region.[18]

Each of these adjustments to current policy have a significant effect on the installed capacities over time, as shown in Figure 22. Overall, the BAU scenarios utilize a mix of new renewables and a significant share of the existing thermal fleet well into the future. A small amount of storage helps meet reserve requirements but is not essential to integrate large amounts of renewable energy. This is largely because the size of PJM and significant number of flexible thermal units on the system allow for enough flexibility to balance intermittent renewable output. When a carbon price is applied across all of PJM, the resulting resource portfolios look similar to the 60% or 80% GHG reduction cases. All coal capacity is retired by 2030 while nuclear capacity is retained, and a larger portion of renewables are built compared to the base BAU case by 2050. When the carbon price is removed, more marginal coal units become uneconomic, likely due to increased competition from gas generation in RGGI states, and slightly less capacity stays online through 2050 versus the Reference case. In the BAU Tech Neutral case, where resource-specific subsidies and carveouts are removed as well, all offshore wind and some nuclear capacity are swapped for additional onshore wind

[17] Rather than set new carbon caps for each RGGI scenario, E3 assumed a set RGGI carbon allowance price forecast for all scenarios, where applicable.

[18] In this scenario, energy from any renewable resource in the PJM system can be used to meet any state's RPS targets.

and solar build and more coal capacity is retained. This suggests that marginal nuclear plants may retire in the long term absent a market that values carbon emissions reductions and that offshore wind is not as economic an option to meet RPS goals as onshore wind and solar.

Figure 22. Installed Capacity Portfolios in 2030 and 2050 for the Core BAU Scenarios

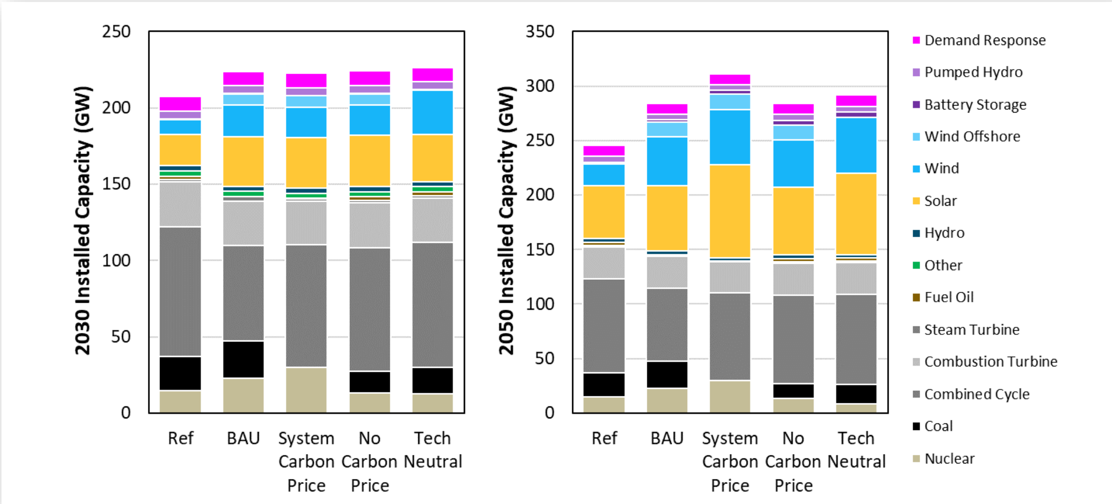
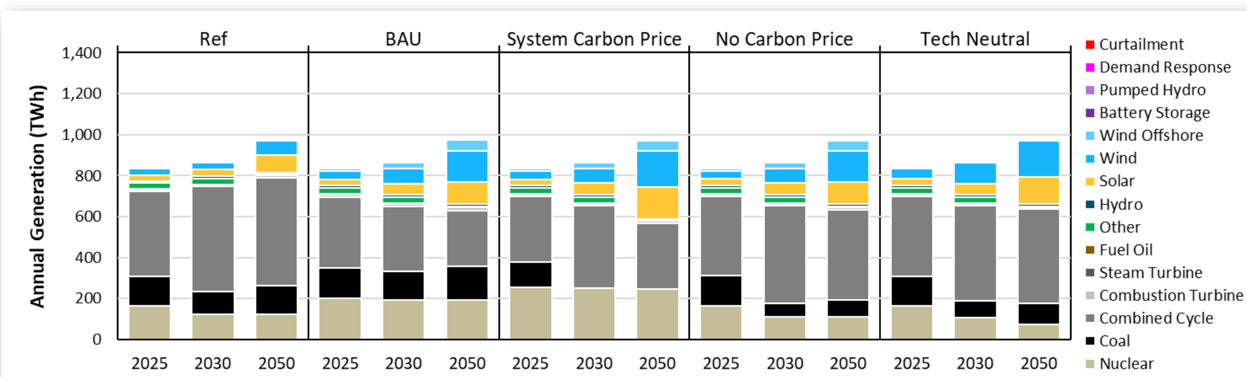


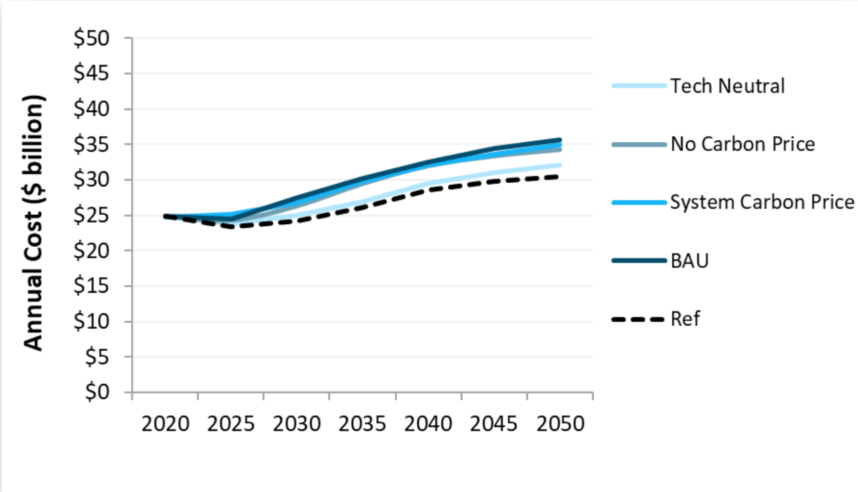
Figure 23 illustrates the annual generation mix across years for the BAU scenarios to provide insight as to how the capacity above is dispatched throughout the year. Following the trend seen in the portfolios, when a carbon price like RGGI is applied across all of PJM, nuclear, lower-emitting gas, and renewables provide around a third of annual generation each. Without a carbon price, cheap coal and gas replace some renewable and nuclear generation. However, the coal and nuclear generation in the BAU case is higher than the BAU No Carbon Price case, while gas generation is much less. This is caused by the 'leakage' phenomenon mentioned previously. In its current structure, RGGI creates a multi-state initiative for decarbonization, but only a few PJM states are participating in the program. Emissions saved by generators in RGGI states are merely shifted over to non-RGGI states, as previously uneconomic units there are now economic units. When resource-specific subsidies and carveouts are also removed, offshore wind and nuclear generation is replaced by some wind, solar, coal, and gas.

Figure 23. Electricity Generation Portfolios in 2025, 2030, and 2050 for the Core BAU Scenarios



The costs for each BAU scenario are shown in Figure 24. Many of the differences highlighted above are reflected in the annual costs. The BAU case is the most expensive because it contains all of the inefficient policies above. Both the BAU System Carbon Price case and the BAU No Carbon Price case are less expensive than BAU. The BAU Tech Neutral case is the least expensive and is only slightly more expensive than the Reference case.

Figure 24. Annual System Costs in 2020–2050 for the Core BAU Scenarios



A carbon price is clearly an effective policy for achieving carbon reductions but has counterintuitive effects when only applied to a portion of the PJM states. The issue of emissions leakage under RGGI has been studied extensively over the past several years. Recent modeling by PJM has tested the implications of wider RGGI coverage and/or border adjustment mechanisms to mitigate emissions shuffling to resources outside of RGGI.[19] PJM's modeling of this issue in PLEXOS differs greatly from E3's approach: PJM uses a more granular production-cost model focused on near-term implications, whereas E3's model is a higher-level approach to capture broad, longer-term impacts. However, both studies have yielded similar findings that suggest wider coverage by RGGI will help mitigate current leakage issues.

Figure 25. Comparison of PJM and E3 Modeling of RGGI

	PJM Modeling of RGGI, February 2020	**E3 Study Representation of RGGI**
Years studied	2023	2020-2050
Model	PLEXOS	RESOLVE
RGGI representation	Base: Current RGGI states + NJ Sensitivities with and without VA, PA	Base: RGGI states + NJ, VA, PA Sensitivities with all PJM
RGGI price scenarios	Specified in single model year: Up to $15/ton in 2023	Specified, escalating by model year: Up to $14/ton in 2030 Up to $38/ton in 2050
RGGI modifications modeled	Border adjustments	n/a
PJM import/export impacts	Included. Increasing RGGI prices and coverage lead to decreased PJM exports and total generation, likely emissions increases outside of PJM.	Not included. Total generation held constant, meaning emissions are not shuffled outside of PJM in response to local carbon prices.

[19] PJM, "Expanded Results of PJM Study on Carbon Pricing & Potential Leakage Mitigation Mechanisms." February 25, 2020. Available at: https://www.pjm.com/-/media/committees-groups/task-forces/cpstf/2020/20200225/20200225-item-03-pjm-study-results-additional-scenarios.ashx

RGGI impact	Emissions and generation impact Varies based on RGGI region Base: net emissions increase, total system generation decreases +VA/PA: net emissions decrease, total system generation decreases Cost impact (no fixed costs) Varies depending on border adjustment assumptions	Emissions and generation impact Varies based on RGGI region Base (incl VA, PA): net emissions increase, same level of system generation All PJM: net emissions decrease, same level of system generation Cost impact (including fixed costs) Higher cost associated with RGGI in all cases

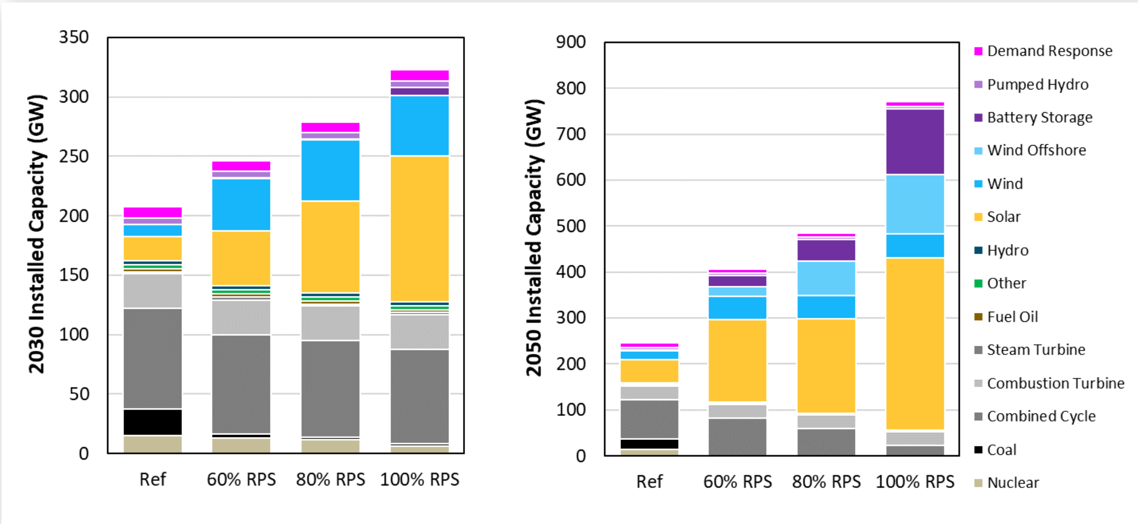
Resource-specific policies encourage uneconomic buildout of offshore wind and uneconomic retention of nuclear units. However, E3 also recognizes that the offshore wind carveouts may enable future cost reductions, like those seen for solar and wind historically, and can serve transmission-constrained coastal cities whose local constraints were not modeled explicitly in this study. As for the policies that incentivize nuclear and coal, results in the following sections consistently show how nuclear generation helps reduce GHG emissions, while coal increases GHG emissions. Market-based policies that directly recognize these different emissions profiles and incentivize carbon reductions in a consistent manner across the PJM system, such as a PJM-wide RGGI carbon program, will yield the most cost-effective achievement of future GHG reduction goals.

4.3.2 Core Renewable Portfolio Standards (RPS) Scenarios

The RPS set of scenarios achieves decarbonization by only incentivizing renewable generation. These policies do not encourage switching to lower-emitting resources (i.e., coal to gas switching) or give credit to other non-emitting resources like nuclear. However, RPS goals can enable storage build since the technology can soak up renewable overgeneration and provide that energy later. This set of RPS scenarios looks at different levels of RPS targets – 60%, 80%, and 100% by 2050.

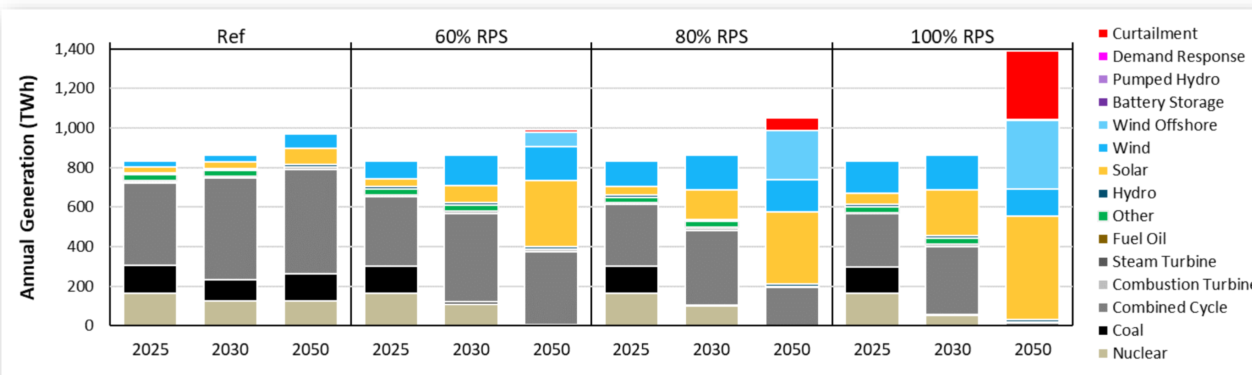
As RPS goals get higher, naturally, this drives more renewable energy capacity on the system. This new capacity removes the need to keep other generators online. In all RPS cases, the coal fleet is retired by 2030 and the nuclear fleet is retired by 2050. Gas capacity is required as the most cost-effective means to maintain reliability, even in the 100% RPS case. Every RPS scenario also sees full buildout of available onshore wind capacity and increasing levels of solar, offshore wind, and storage in 2050 as the RPS goal increases. Also, because solar and wind have capacity factors around 25% and 35%, respectively, higher RPS goals lead to much higher levels of installed capacity overall. In the 100% RPS case, the 2050 total installed capacity reaches over 750 GW for a system peak of around 180 GW.

Figure 26. Installed Capacity Portfolios in 2030 and 2050 for the Core RPS Scenarios



The annual generation mix in the different RPS scenarios across years is shown in Figure 27. In general, as the RPS target becomes more stringent, substantial wind and solar generation replaces thermal generation, which comes with increased levels of curtailment. Despite the significant amount of storage capacity that accompanies renewable build, the curtailment suggests that it is more economical to overbuild and curtail some renewable generation than to build enough storage to soak up all renewable overgeneration. Natural gas combined cycles provide a large share of energy in 2050 except in the 100% RPS case, in which a very small amount of gas generation and other existing thermal renewable resources are used on days with very low renewable output.

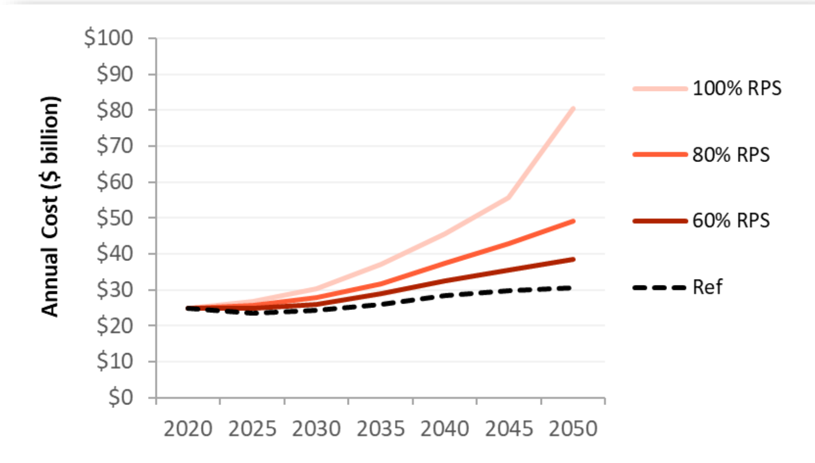
Figure 27. Electricity Generation Portfolios in 2025, 2030, and 2050 for the Core RPS Scenarios



The system costs across analysis years for these RPS scenarios are shown in Figure 28. As expected, system costs increase with time and more ambitious RPS targets. Specifically, the cost of reaching a 100% RPS target in 2050 grows exponentially and is substantially higher than the costs of reaching lower GHG targets. This "hockey stick" trend is consistent with previous studies for other regions.[20]

[20] E3, 2019, *Resource Adequacy in the Pacific Northwest*. https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf

Figure 28. Annual System Costs in 2020–2050 for the Core RPS Scenarios

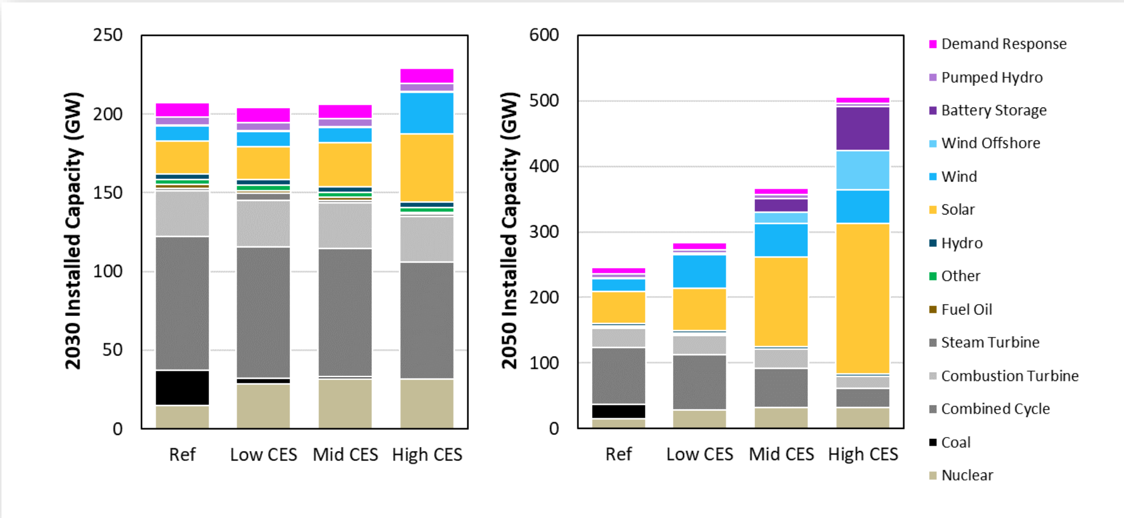


4.3.3 Core Clean Energy Standards (CES) Scenarios

By allowing existing nuclear to receive clean energy credit for its emissions-free attribute and gas to receive partial credit, the CES scenarios show some similar patterns to the RPS set but result in lower costs due to the reduced renewable energy and storage capacity needed to achieve the CES goals. A portfolio content policy (i.e. targets based on percent of annual generation) that assigns credit based on each resource's emissions rate effectively yields a GHG target by proxy. For example, one MWh of solar will get the same credit as one MWh of nuclear because both have no emissions associated with the MWh. Efficient gas CCs receive less credit than renewables or nuclear but more credit than gas CTs which emit more carbon per unit of energy. A coal generator, which typically has the highest emissions rate, receives no credit toward the CES goal. Credits are awarded per unit of generation regardless of the marginal system resource, which is analogous to how RECs are generated under the RPS scenarios. The policy targets for the CES cases in this study are designed to achieve similar emissions reductions to the 60%, 80%, and 100% GHG reduction by 2050 cases and are labeled as the Low, Mid, and High CES cases.

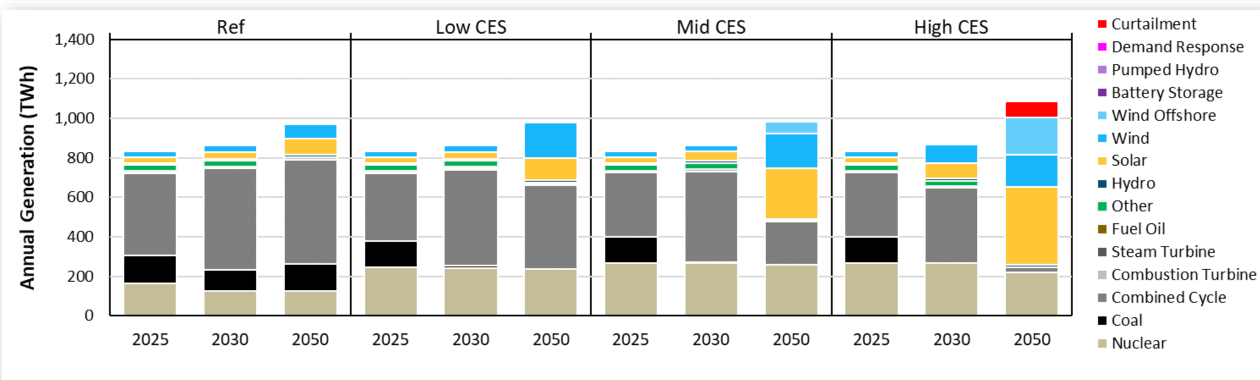
For the CES scenarios, the amounts of solar, onshore and offshore wind, and storage increase as CES targets become larger. The slight difference between the CES and RPS builds is the retention of nuclear through 2030. Most of the coal is eliminated by 2030 across all cases in favor of increased gas generation, new renewables, and continued nuclear generation. Figure 29 shows that, through 2030, the capacity mix is relatively unchanged by the CES target in question; yet after 2030 and until 2050, there are noticeable differences in installed capacity.

Figure 29. Installed Capacity Portfolios in 2030 and 2050 for the Core CES Scenarios



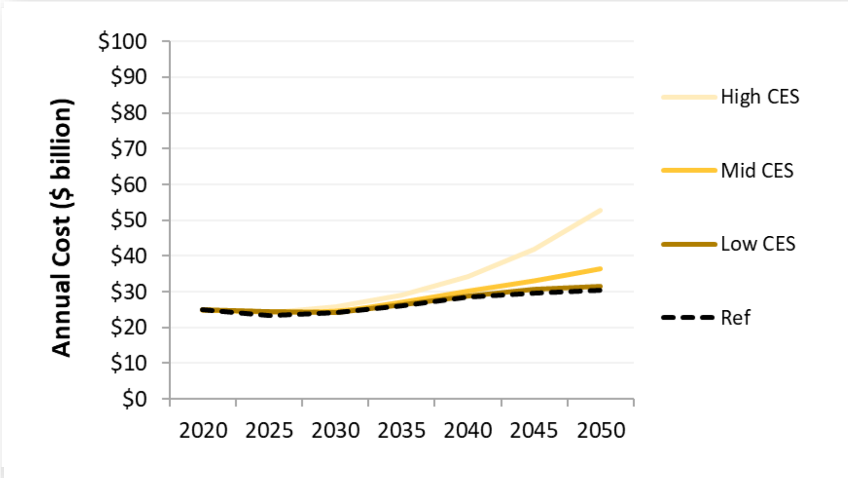
Regarding annual generation, the CES scenarios show consistently higher levels of nuclear generation and lower levels of renewables and curtailment than the RPS scenarios. Awarding credit to nuclear and gas nearly eliminates curtailment except for in the 100% CES case. Like the RPS case, even though a significant amount of storage is built, it is still optimal to overbuild renewables and allow a sizeable amount of curtailment.

Figure 30. Electricity Generation Portfolios in 2025, 2030, and 2050 for the Core CES Scenarios



The annual costs to achieve higher and higher CES goals have a similar pattern to the RPS cost trajectories but are lower each year. This is logical as many existing resources can help contribute to the target instead of relying heavily on new renewable investment.

Figure 31. Annual System Costs in 2020–2050 for the Core CES Scenarios



4.3.4 Core Greenhouse Gas (GHG) Reduction Scenarios

Instead of decarbonizing the system by setting generation targets for various sets of resources, the GHG reduction scenarios put an annual limit on GHG emissions. This mechanism is similar to RGGI, but with some key differences. Here, the limit covers all of PJM's territory and there is no price cap or floor. In RESOLVE, investments and dispatch decisions are made simultaneously to ensure the GHG limit is not exceeded. This construct allows RESOLVE to calculate an effective GHG price each year – representing the marginal cost of meeting the constraint.

In addition to the non-GHG-emitting renewable and nuclear resources, this type of policy encourages more-efficient, lower-emissions resources to replace less-efficient, higher-emitting ones (i.e., switching from coal to gas). This scenario also allows gas generators to drop in a limited amount of biofuels in later years to effectively be carbon-free[21]. Overall, the core GHG reduction scenarios build less renewable capacity compared to the RPS cases, retire the coal fleet by 2030, and keep nuclear capacity online to meet the GHG targets.

[21] Biofuel blending was limited to 180 billion MMBtu in 2045 and 200 billion MMBtu in 2050, which is consistent with E3 PATHWAYS work investigating the future of biofuels.

Figure 32. Installed Capacity Portfolios in 2030 and 2050 for the Core GHG Reduction Scenarios

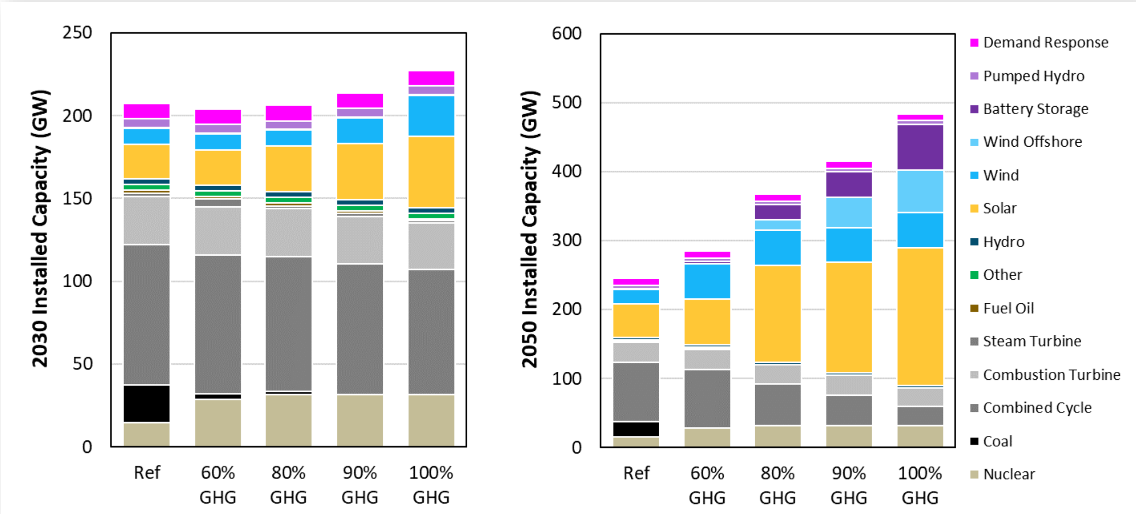


Figure 33 shows more nuclear generation and reliance on gas with increased levels of renewables to help meet GHG goals. As the GHG reduction target increases, renewable resources replace gas generation, while nuclear generation remains constant. Nuclear resources can provide firm generation at lower costs compared to new renewable builds, especially by 2050 in the 90% and 100% GHG cases, where renewable capacity is already overbuilt and contributes to high levels of curtailment. In these high-achievement cases, gas units blend in biofuels in 2050 to provide carbon-free energy, which also avoids renewable overbuild and increased curtailment.

Figure 33. Electricity Generation Portfolios in 2025, 2030, and 2050 for the Core GHG Reduction Scenarios

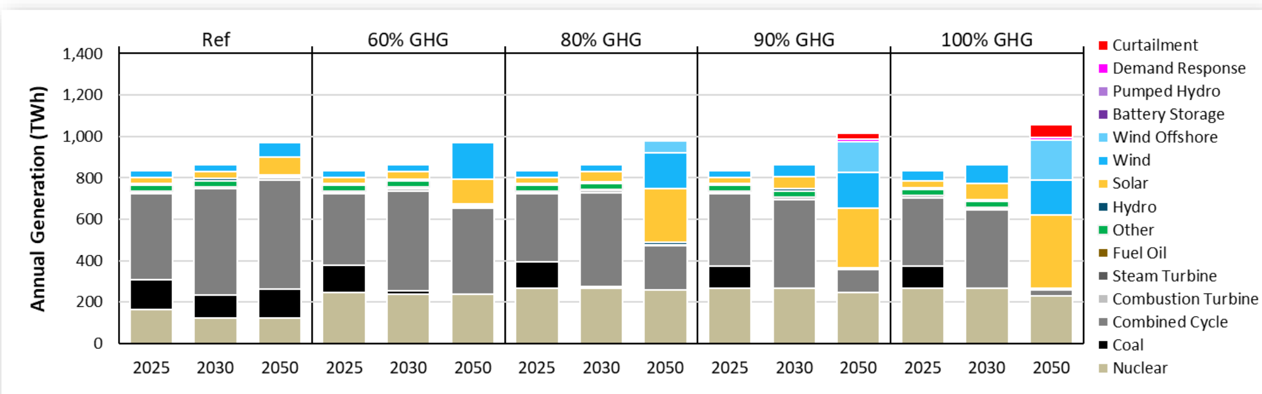
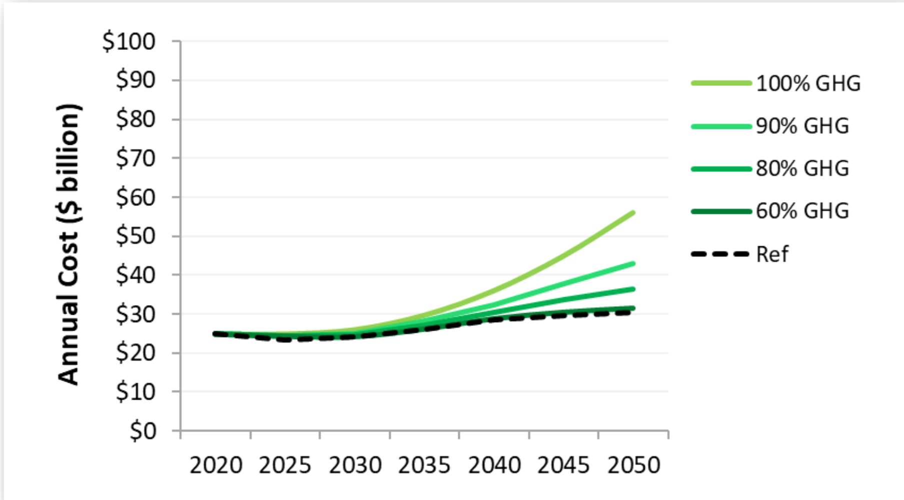


Figure 34 illustrates how the GHG scenarios still have exponentially increasing costs to achieve higher levels of decarbonization. However, achieving a similar level of emissions using other policy mechanisms is always more expensive than the GHG cases, where emissions are targeted directly. For example, the 100% GHG case compared to the 100% RPS case has costs that are around 25% lower by 2050. This is because this set of scenarios puts all resources on an equal playing field and encourages all strategies for GHG reductions – investment in renewable energy, coal-to-gas switching, and retaining carbon-free nuclear energy.

Figure 34. Annual System Costs in 2020–2050 for the Core GHG Reduction Scenarios



4.4 Sensitivity Details

Following on from the core scenarios, further sensitivities were conducted to gain a more complete understanding of the different policy mechanisms and their effects on the future PJM system. The impact of land constraints on the resource mix was one key sensitivity studied. The other sensitivity allowed other firm, carbon-free technologies to be selected to meet policy goals – specifically new nuclear SMRs and gas with 90% CCS.

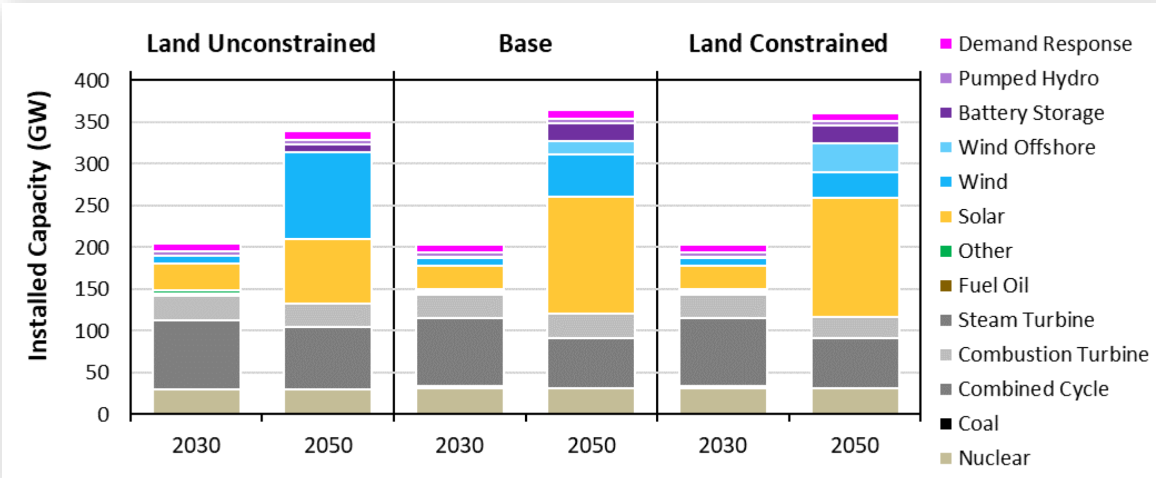
4.4.1 Impact of Land Use Constraints on Renewable Development

E3 applied a substantial reduction to the technical resource potentials reported by NREL for this study. The core scenarios restricted land use to 4% of farmland for solar and 4% farmland and 2% forested land for onshore wind. The results showed onshore wind resources often reached the maximum allowed capacity, using all land available. This sensitivity set explores the implications of the land use restriction assumptions. In one case for this sensitivity, the restricted resource potentials for onshore wind were rolled back to the original technical potentials. In the other, resources were further constrained to half of the core scenarios' available land use. The 80% GHG scenario was chosen as the base scenario to study the effects of this assumption.

As seen across the core set of scenarios, offshore wind is only chosen after onshore wind because of offshore wind's higher cost and similar energy profile.[22] The model also tends to select additional solar once onshore wind potential is depleted. In the unconstrained land use sensitivity, the model selects no offshore wind and much less solar than the base 80% GHG scenario. This sensitivity also sees lower levels of battery storage because the reduced solar capacity eases integration needs. On the other hand, when land use is further constrained, both onshore wind and solar reach their land use limit and the model selects much more offshore wind to reach the GHG goal. Figure 35 shows a comparison of installed capacity for these cases.

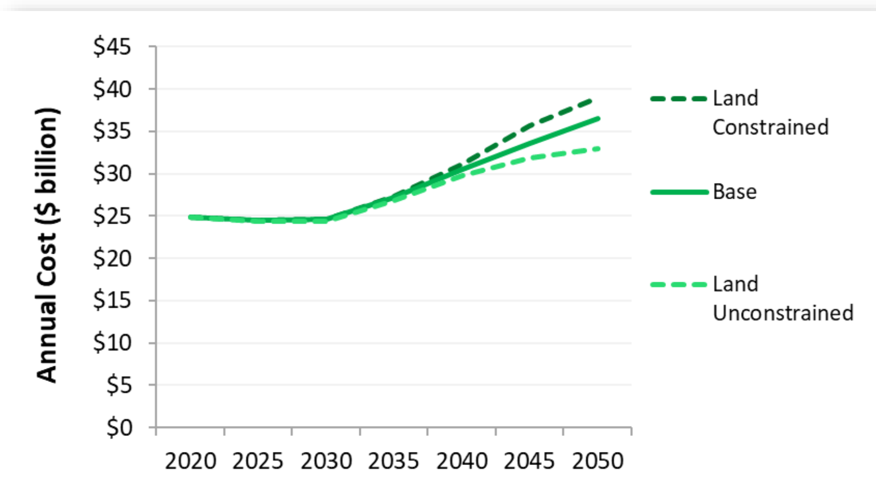
[22] While the best offshore wind resources yield greater average generation per megawatt of capacity ("capacity factor") than most onshore wind resources, this generation is spread in a similar pattern over the course of the day and year.

Figure 35. Portfolio Comparison for 80% GHG Land Use Sensitivities in 2030 and 2050



Offshore wind is more expensive than onshore wind but has a similar production pattern over the course of the day, whereas solar is cheaper but has a lower capacity factor and produces all of its energy in a concentrated set of hours in the middle of the day. RESOLVE prefers a portfolio of complementary solar and onshore wind to achieve high emissions reductions goals at least cost. When land use is restricted, this complementary portfolio is no longer available at scale, leading RESOLVE to select a more costly mix of alternative resources. The cost implications of the land use constraints are shown in Figure 36. The cost gap will only widen under more stringent carbon reduction targets.

Figure 36. Annual Cost Comparison for 80% GHG Land Use Sensitivities



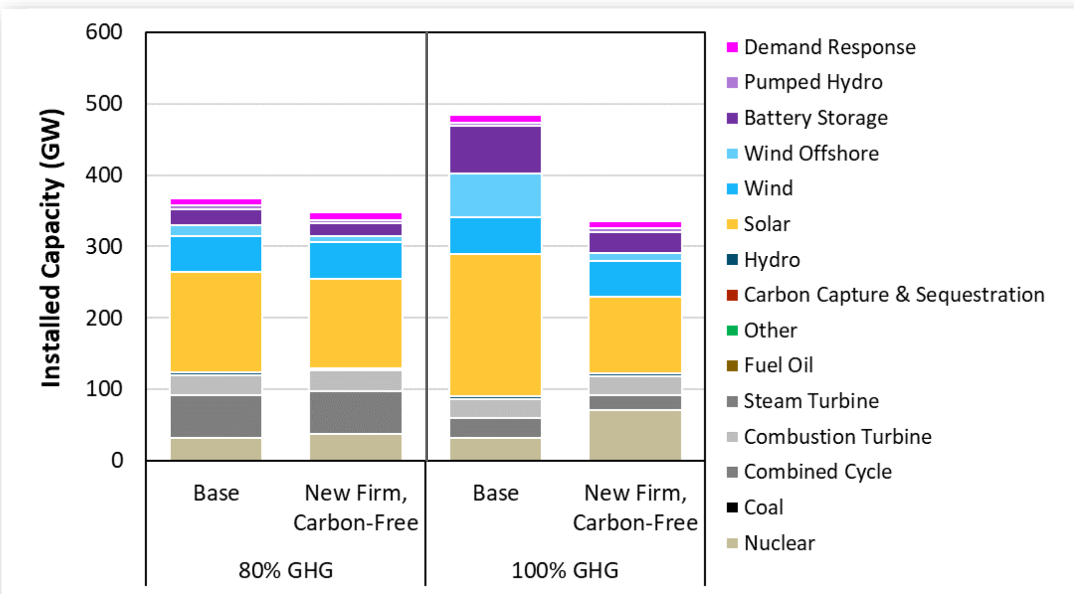
E3 recognizes that it is unclear whether the levels of offshore wind development shown are feasible, given only onshore wind and solar were restricted. However, this land-use sensitivity highlights the long-term challenges that will be encountered under deep decarbonization goals. Either a greater portion of land than assumed in this study must be developable, resources must potentially be procured from outside the PJM region, or some other carbon-free resource must be incentivized or commercialized to meet deep levels of decarbonization while minimizing cost.

4.4.2 Long-Term Demand for Firm, Carbon-Free Energy

One of the greatest challenges to decarbonizing electricity systems is the intermittency of renewable resources like wind and solar. Having resources that can be relied upon to quickly turn on when a higher demand is anticipated is crucial in an industry that is expected to provide electricity every hour of every day. It is expected that energy storage resources, which can soak up excess wind and solar energy, will help with the intermittency issues; but sometimes long periods of low renewable output can cause storage resources to be unreliable. The value of firm, zero-carbon resources has already been seen in the core cases, where nuclear is eligible to meet carbon reduction goals. However, the core scenarios modeled did not allow for new firm, carbon-free resources to be built. This sensitivity offers those as options to achieve decarbonization.

There are many promising technologies under development that are both carbon free (or have very low emissions) and firm (can be operated flexibly, turning on whenever needed). The technologies used for this sensitivity are nuclear SMRs and 90% capture rate CCS; however, it is possible that there will be other firm, carbon-free resource developed in the future that would result in similar trends as the results shown below. It should be noted that the current feasibility of integrating nuclear SMRs and CCS are limited; this sensitivity assumes a future where these resources become more commercially mature and are deployed at scale and cost points that are not available today. This sensitivity on future clean, firm resource availability was modeled for the high-achieving 80% and 100% GHG reduction cases. Figure 37 below shows the 2030 and 2050 installed capacities across the different cases. Most of the new firm, carbon-free resources are built by 2050, when the carbon reduction targets become most stringent to meet.

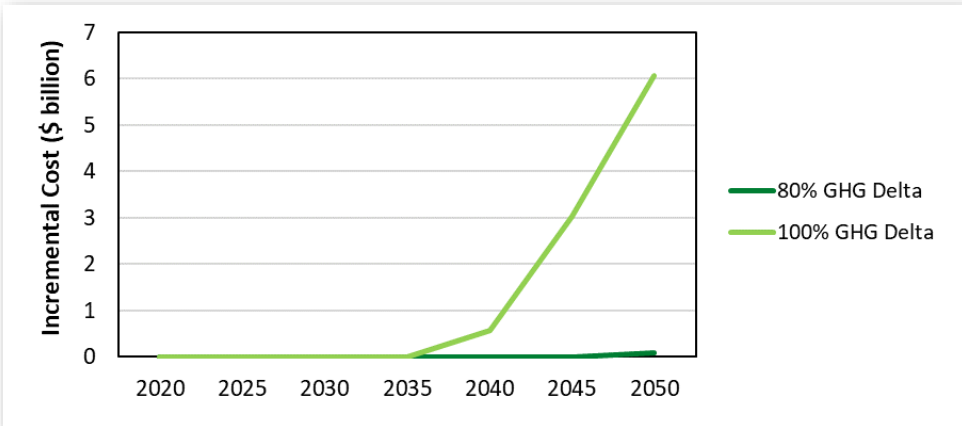
Figure 37. Installed Capacity Comparison in 2050 for Firm, Carbon-Free Sensitivities



These firm, carbon-free technologies are more valuable when trying to achieve very high decarbonization goals – in the 100% GHG reduction cases, specifically – if commercially available in the future. An additional 40 GW of nuclear SMRs would reduce the need for significant amounts of solar, storage, and offshore wind to meet these goals. This has a significant impact on costs for the 100% GHG cases in the long term. For the 80% GHG reduction cases, RESOLVE selects a significantly smaller amount of nuclear SMR capacity, which leads to similar 2050 costs under this future technology availability sensitivity. This suggests that if advanced technologies can offer firm, clean power at a cost of $63/MWh by 2050 (in real 2018 $), as assumed in this sensitivity, they would offer system cost savings under deep decarbonization goals of 80% or greater. However, at this cost, their value would still be limited under less ambitious carbon reduction targets.

The incremental costs for achieving the associated GHG target without new firm, carbon-free resources (i.e., the potential savings if these resources are available at projected costs) can be seen in Figure 38.

Figure 38. 2050 Incremental Cost of GHG Reduction Scenarios with and without Firm, Carbon-Free Resource Options



5 Conclusions

The modeling in this study suggests that PJM states have much to gain by transitioning to a more regional, technology-neutral policy framework for addressing climate change. Current state policies, as represented in the BAU scenario, appear largely inefficient at reducing GHG emissions today. E3's BAU scenario shows additional system costs of over $3 billion per year by 2030, or $50 per person each year across the 65 million customers served by the PJM system today, for a 12% reduction in net GHG emissions. However, major GHG reductions are viable at low total cost. A minimal carbon price applied across PJM, as an example, could reduce systemwide emissions by over 35% by 2030 from today's levels at near zero net cost. Low-cost GHG savings in PJM are driven by the near-term opportunity to retire aging coal plants and replace their production with more efficient gas generation and renewables. Yet beyond 2030, the costs of GHG reductions begin to increase. To meet deeper long-term decarbonization goals, effective policy choices that leverage all potential technologies and the resource diversity of the wider PJM grid will be increasingly important. A regional carbon price applied throughout PJM would most directly and cost effectively serve this purpose, while a regional CES that enables trading of low-carbon energy across the PJM system could arrive at a similarly cost-effective future resource mix centered around renewables, nuclear, and flexible thermal generation.

5.1 Implications for Current Policy

E3's modeling consistently shows the inefficiency of current policies that aim to reduce GHG emissions by subsidizing specific technologies or in-state resources. Prescriptive policy mechanisms, such as RPS policies, will become less and less cost-effective as policy targets reach higher levels, like the 50%+ targets that have become more widespread since 2015. To improve policy performance, E3 sees significant value in more technology-neutral approaches, such as CES or carbon pricing programs, that do not limit the set of eligible tools for GHG reductions.

Policymakers and their constituents would benefit from long-term goals that more directly reflect the end goal of reduced GHG emissions. E3's study shows that technology-neutral policies that enable the broadest array of potential solutions will generally be the most cost-effective by incentivizing coal-to-gas switching, retaining the most competitive zero-emission nuclear generators, and developing the lowest-cost renewables that harness the diversity benefits of PJM's geography. Defining goals in more direct terms of GHG reductions also enables more comprehensive climate change policy that weighs power-sector goals within the broader context of economywide decarbonization. Prior studies by E3 have shown that the power sector plays an important role in driving GHG savings from transportation, buildings, and other major sources of emissions. Policy focused on emissions intensity is a step towards harmonizing these long-term options for decarbonization.

E3's study suggests that several current state policies that are well-intentioned may not have the intended effect. For example, the RGGI program that currently covers a fraction of PJM states has limited or negative impact on emissions today due to leakage, whereby compliance costs within the RGGI region incentivize a shift in energy production to less efficient resources outside of the RGGI region. PJM is currently modeling border adjustment mechanisms that seek to remedy this issue. E3 finds that expansion of RGGI to all PJM states is another approach that would eliminate leakage and improve the effectiveness of this program at reducing GHG emissions. E3 also finds that current resource-specific mandates for offshore wind and battery storage in PJM appear premature if immediate GHG reductions or cost savings are the intended goals. E3's modeling suggests that these resources will not be needed to meet decarbonization goals within PJM until after the 2030 timeframe. Instead, targeting cheaper onshore resources would reduce emissions at significantly lower cost over the next decade. E3 recognizes that technology transformation, local jobs and tax revenues, and other incentives are likely motivators beyond the value analyzed in this study. However, this study shows the net cost associated with pursuing these technology-specific carveouts may total over $1 billion per year versus more readily available GHG savings opportunities.

The good news is that significant emissions reductions are likely in PJM. Favorable economics will drive a cleaner generation mix over the coming decade as gas and renewables increasingly offset coal generation. Improvements to mitigate leakage in the RGGI program and/or expansion of this program to cover more of PJM could drive significantly deeper emissions reductions. Investors are already planning for this future in their financial risk assessments, which increasingly put a price on future carbon risk. According to E3's modeling, the power sector will be able to claim easy wins in the near term by reducing GHG emissions substantially at very low cost.

5.2 Longer-Term Policy Implications

Beyond 2030, efficient policy design and resource usage will become increasingly important to meeting GHG reduction goals at a reasonable cost. E3 finds that while sufficient renewable resources exist to reach 2030 goals, more ambitious 2050 goals will require a transformation in land usage with onshore resources being insufficient to meet clean energy demand even if 4% of existing farmland is dedicated to renewable energy. The development potential of renewable resources is a key question for the achievability of long-term clean energy goals, particularly in wind-rich states that have historically pushed back against the siting and permitting of new projects. While E3 has begun to quantify the potential land requirements associated with deep decarbonization, additional work is needed to quantify the true availability of onshore wind resources.

Solar appears less limited by inherent resource quality; however. additional work may be needed to identify transmission constraints that may be associated with the solar development forecasted in the model. For example, solar-rich states like Virginia may face new local transmission constraints if solar capacity for supplying the remainder of PJM is sited predominantly in sunnier, southern regions.

Another key factor in achieving long-term decarbonization goals is the availability of firm, flexible capacity to backstop the grid in hours when renewable generation is low. E3 finds that the deep pool of flexible gas capacity in PJM will allow it to integrate renewables at low cost, though gas plant operations will look significantly different in the future. Gas plants will likely see increased cycling (starts and stops), more seasonal operations, and lower total emissions at each plant as renewables displace current reliance on thermal generation. By 2050, E3 sees at least 35 GW and likely 50-80 GW of existing gas capacity remaining valuable for grid reliability. The value of these plants will be concentrated in fewer hours of the year, suggesting that more volatile energy prices may occur in these hours or higher capacity prices may be required to keep plants online for reliability alone.

E3 also sees limitations in the ability of existing technologies to meet any variation of the 100%-style goals set today at reasonable cost. Policies that require 100% renewable, 100% clean, or 100% GHG-free energy by 2050 would lead to exponential increases in costs to show compliance beyond the 80% threshold. For example, moving from 80% GHG reductions to 100% reductions in 2050 would drive additional costs of over $20 billion/year. Moving from 80% to 100% RPS policy would increase costs by over $30 billion/year, or over $400 per person per year. The largest driver of this cost increase is the current lack of zero-emission generation that can reliably serve load in periods of low renewable energy generation. Future technologies that provide firm, low- or zero-emission power such as CCS, new nuclear, or long-duration energy storage may have a role in reaching such 100% policy goals at a more achievable cost. However, these are pre-commercial technologies today and continued cost declines will be necessary to unlock their potential.

The cost efficiencies of a broad, regional marketplace such as PJM are clear today. For example, coastal jurisdictions with limited land available for renewable development (like Maryland and Washington, DC) already rely on clean energy from other parts of the PJM system, such as wind power from Illinois, to meet their environmental goals at the lowest cost. Continued movement towards more regional policy solutions will be necessary to minimize costs and maximize the impact of state climate initiatives. New Jersey's planned transition away from solar REC carveouts is an example of a step in the right direction. Similar policy evolution towards more regional clean energy markets, rather than local resource-specific subsidies, will allow states to benefit from competition among clean energy suppliers and will lead to lower bills for consumers.

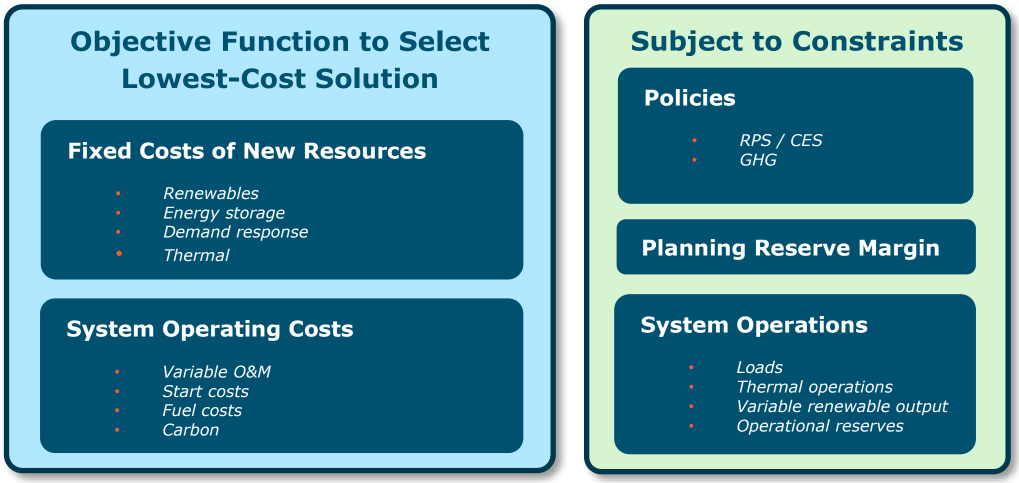
E3's study shows that the diversity of the PJM system's loads and resources offers significant cost savings for meeting the collective climate goals of the region. As states within the PJM grid continue to refine their climate change policies, policymakers should see the regional marketplace as a critical tool for enabling long-term decarbonization. Efficient policy will be key to meeting climate goals at manageable costs.

6.1 PJM Renewable Energy Solutions (RESOLVE) Model

System planning in the power sector is an established practice that utilities and system operators perform to ensure the lights stay on. At its core, system planning relies on models that simulate the grid to determine if there are enough resources capable of supplying energy to meet consumer demand (load) across many time horizons. One form of a planning model is a "production simulation model," which balances loads and resources on an hourly basis over multiple years. This model calculates marginal system costs by optimally dispatching resources at lowest cost to meet hourly energy demand. Another system planning tool is a "capacity expansion model," which forecasts long-term system needs and makes optimal resource investment decisions to ensure future peak demand can be reliably met. Many different constraints, such as resource operations, reserve requirements, transmission deliverability issues, emissions policies, and many others are applied to these models to create an accurate representation of a power system like PJM.

E3's RESOLVE model was used to study the implications of current and potential decarbonization strategies for PJM's system, given the global effort to reduce greenhouse gases. RESOLVE is a resource planning model that identifies optimal long-term generation investments in an electric system, subject to reliability, technical, and policy constraints. Designed specifically to address the capacity expansion questions for systems seeking to integrate large quantities of variable resources, RESOLVE layers capacity expansion logic on top of a reduced-form production cost model to determine the least-cost investment plan, accounting for both the up-front capital costs of new resources and the variable costs to operate the grid reliably over time. In an environment in which most new investments in the electric system have fixed costs significantly larger than their variable operating costs, this type of model provides a strong foundation to identify potential investment benefits associated with alternative scenarios.

Figure 39. Diagram of RESOLVE Modeling Methodology



To identify optimal investments in the electric sector, maintaining a robust representation of prospective resources' impact on system operations is fundamental to ensuring that the value each resource provides to the system is captured accurately. At the same time, the addition of investment decisions across multiple periods to a traditional unit commitment problem increases its computational complexity significantly. RESOLVE's simulation of operations has therefore been carefully designed to simplify a traditional unit commitment problem, where possible, while maintaining a level of detail sufficient to provide a reasonable valuation of potential new resources. The key attributes of RESOLVE's operational simulation are enumerated below:

+ Hourly chronological simulation of operations: RESOLVE's representation of system operations uses an hourly resolution to capture the intraday variability of load and renewable generation. This level of resolution is necessary in a planning-level study to capture the intermittency of potential new wind and solar resources, which are not available at all times of day to meet demand and must be supplemented with other resources. E3's Day Sampling Algorithm (described in the Appendix) is used to identify 40 representative days to model, which ensures that a statistically significant set of system conditions are captured.

+ Planning reserve margin requirement: When making investment decisions, RESOLVE requires the portfolio to include enough firm capacity to meet coincident system peak plus an additional 9% of planning reserve margin (PRM) requirement. The contribution of each resource type towards this requirement depends on its attributes and varies by type. For instance, variable renewables are discounted compared to thermal generators because of limitations on their availability to produce energy during peak hours.

+ Renewable Portfolio Standard (RPS): For both investments and operations, RESOLVE can ensure a set of resources produces a specific amount of energy each year. This feature is mostly used to model RPS targets, but other types of policies can be modeled, like a Clean Energy Standard (CES), where other low-carbon generation may count towards the target.

+ Greenhouse gas cap: RESOLVE also allows users to specify and enforce a greenhouse gas constraint on the resource portfolio for a region. As the name suggests, the emission cap requires that annual emission generated in the entire system to be less than or equal to the designed maximum emission cap. As it designs future portfolios, RESOLVE chooses both (1) how to dispatch new and existing resources to meet the goal (e.g., displacing output from existing coal plants with increased natural gas generation) and (2) what additional investments are needed to further reduce carbon in the system.

RESOLVE requires a wide range of inputs and assumptions to ensure accurate representation of the PJM system. Whenever possible, data from PJM was used; however, a significant portion relied on other public sources and E3 expertise. The following sub-sections describe the buildup of these assumptions and include the categories listed in Table 7.

Table 7. Descriptions of Key Input Assumptions for the RESOLVE Model

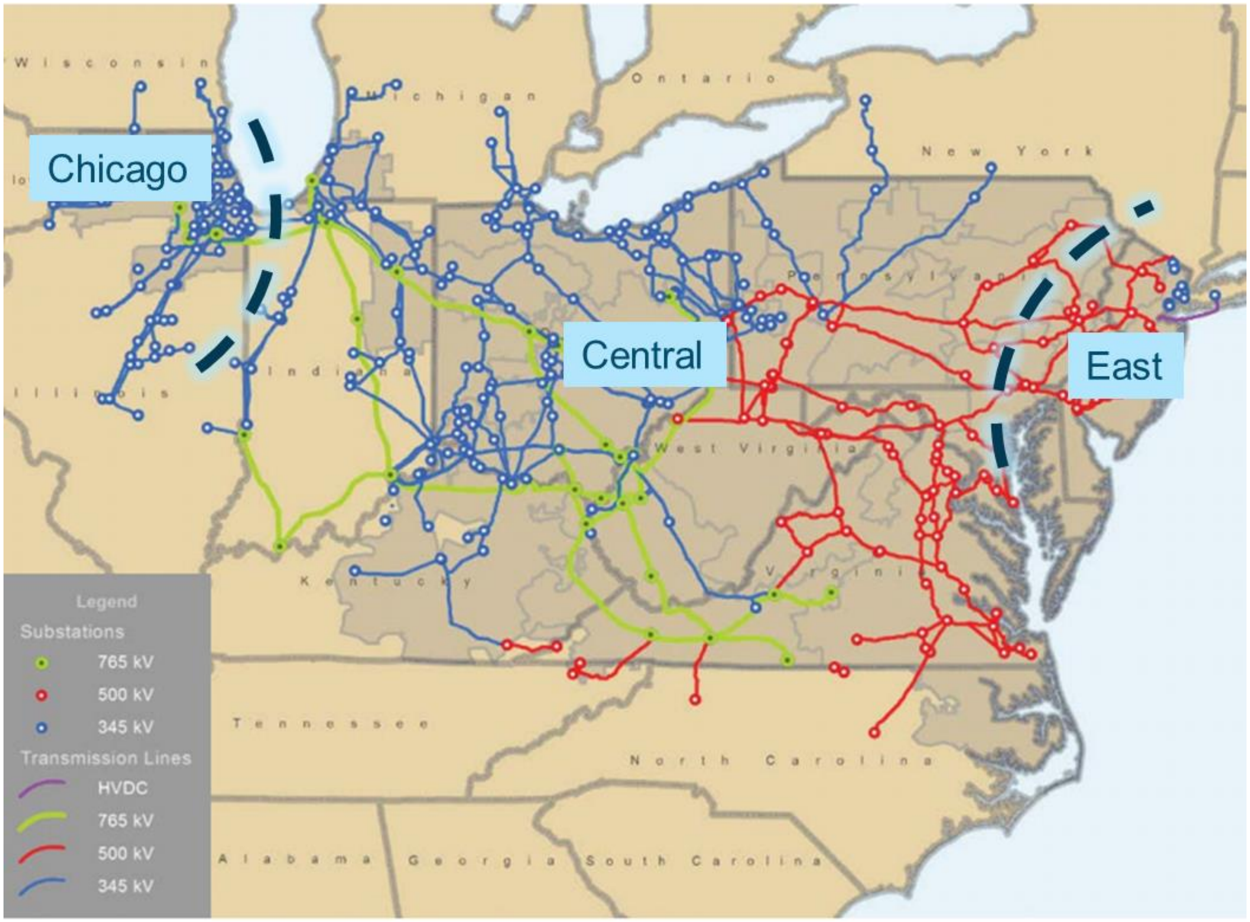
Input Category	Description
System Topology	PJM's zonal representation in RESOLVE: transmission and capacity constraints
Demand Forecast	Annual demand and peak forecast for each RESOLVE zone
Existing Resources	Capacity, operating characteristics, and aggregation of existing and planned resources
New Resources & Costs	Supply curve buildup for renewables and cost assumptions for all new resources
Hourly Profiles	Load profiles used and renewable profile development for existing and new resources
Fuel Price Forecasts	Gas, coal, and uranium price forecasts
Reliability Accounting	ELCC surfaces for renewables and storage; NQC accounting for thermal resources
Policy Constraints	Representation of RPS, CES, CES+, and GHG reduction targets

The following sections describe the input assumptions used in the RESOLVE model.

6.1.1 Model Topology

The PJM footprint spans multiple states across the eastern and central areas of the United States. The model zones implemented within RESOLVE represent high-level system constraints or bottlenecks in the PJM grid. The PJM territory has natural congestion due to transmission limits towards load pockets. This occurs towards the East and to a lesser extent within the ComEd region. Transfer interface limits set by PJM also restrict power flow on the high-voltage transmission network to prevent voltage contingency violations. Two of these transfer limits, illustrated in Figure 40, are between the RTO-Eastern Mid-Atlantic Area Council (EMAAC) interface and the RTO-ComEd interface, naturally splitting PJM into three zones: ComEd, RTO, and EMAAC.

Figure 40. High-Voltage Transmission Map Highlighting Modeled RESOLVE Zones



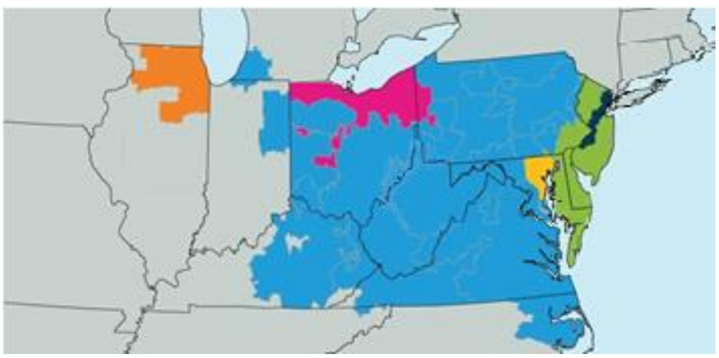
The three regions described above align, to a certain extent, with capacity auction zones in PJM. Figure 41 and Figure 42 show that, though the zones change depending on the delivery year, the main regions that remain intact are the ComEd, EMAAC, and RTO regions. There may be smaller sub-regions that emerge within these areas depending on the auction year, yet the main zones are a reasonable representation of local transmission constraints and capacity needs within the PJM territory. These zones are used in RESOLVE and naming conventions used in this report are the following:

+ Chicago: consists of ComEd in Northeastern Illinois.
+ East: consists of load serving entities (LSEs) in the EMAAC region, including those in New Jersey, Delaware, Southeast Pennsylvania, and Eastern Maryland.
+ Central: consists of remaining LSEs in central PJM, which is highly interconnected by high-voltage transmission lines and settles at the lowest capacity prices in the PJM.

Since model zones align with the capacity auction zones of ComEd, EMAAC, and RTO, the Capacity Emergency Transfer Limits (CETLs) for ComEd and EMAAC are used as the transfer limits between these two zones and the RTO zone. The zonal import and export capabilities implemented in the model are taken as 5,971MW for transfers between ComEd and RTO, and 9,752MW for transfers between EMAAC and RTO. These CETL values are based on the 2022/2023 Base Residual Auction parameters.[23]

Figure 41. PJM Capacity Auction Outcomes for Delivery Year 2018/2019

Figure 42. PJM Capacity Auction Outcomes for Delivery Year 2021/2022



No external zones were modeled in RESOLVE, meaning PJM is unable to import or export to the Midcontinent Independent System Operator (MISO), the New York Independent System Operator (NYISO), or the Tennessee Valley Authority (TVA). PJM is a net exporter to MISO and NYISO, and TVA; with interconnection capacities of around 50 GW, 4 GW, and 4 GW, respectively. These represent 27%, 2%, and 2% of PJM's total installed capacity; however, flows between these entities never reach the full interface capability and exports typically average 2% to 5% of PJM load, up to a maximum of around 10%. E3 assumes these interactions would not have a significant impact on PJM resource investments in the long run. Neighboring grids such as NYISO and MISO will likely see similar levels of increasing renewables on their systems. As they face further decarbonization policies, marginal costs will likely look similar to PJM's and there would be little benefit to modeling these flows. The results depicted in this report represent how PJM could plan its system to meet all load and achieve various levels of GHG reductions.

6.1.2 PJM System Current and Forecasted Load

Load assumptions used in RESOLVE modeling are primarily based on the PJM Load Forecast Report published in January 2020.24 Load forecast data for the three RESOLVE zones are aggregated from data for each of the utilities in

[23] 2022/2023 RPM Base Residual Auction Planning Period Parameters Report, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-rpm-bra-planning-parameters-report.ashx?la=en

[24] PJM Load Forecast Report, PJM Resource Adequacy Planning Department, January 2020. https://www.pjm.com/-/media/library/reports-notices/load-forecast/2020-load-report.ashx?la=en.

PJM. Utility-level data in the PJM Load Forecast Report are available for 2020-2035. Aggregated load data are extrapolated through 2050 using 2020-2035 compound annual growth rates for each RESOLVE zone. Annual gross energy and peak demand forecasts over the years are shown in Figure 43 and Figure 44, respectively. Overall, load growth across the PJM zones is moderate over time. PJM-wide gross energy increases from approximately 791 TWh in 2020 to 971 TWh in 2050, at a growth rate of 0.7% per year. PJM-wide gross peak demand increases from approximately 150 GW in 2020 to 181 GW in 2050, at a growth rate of 0.6% per year.

Figure 43. Annual Gross Energy Forecasts for RESOLVE Zones (Central, Chicago, East) and Breakdown by Utility

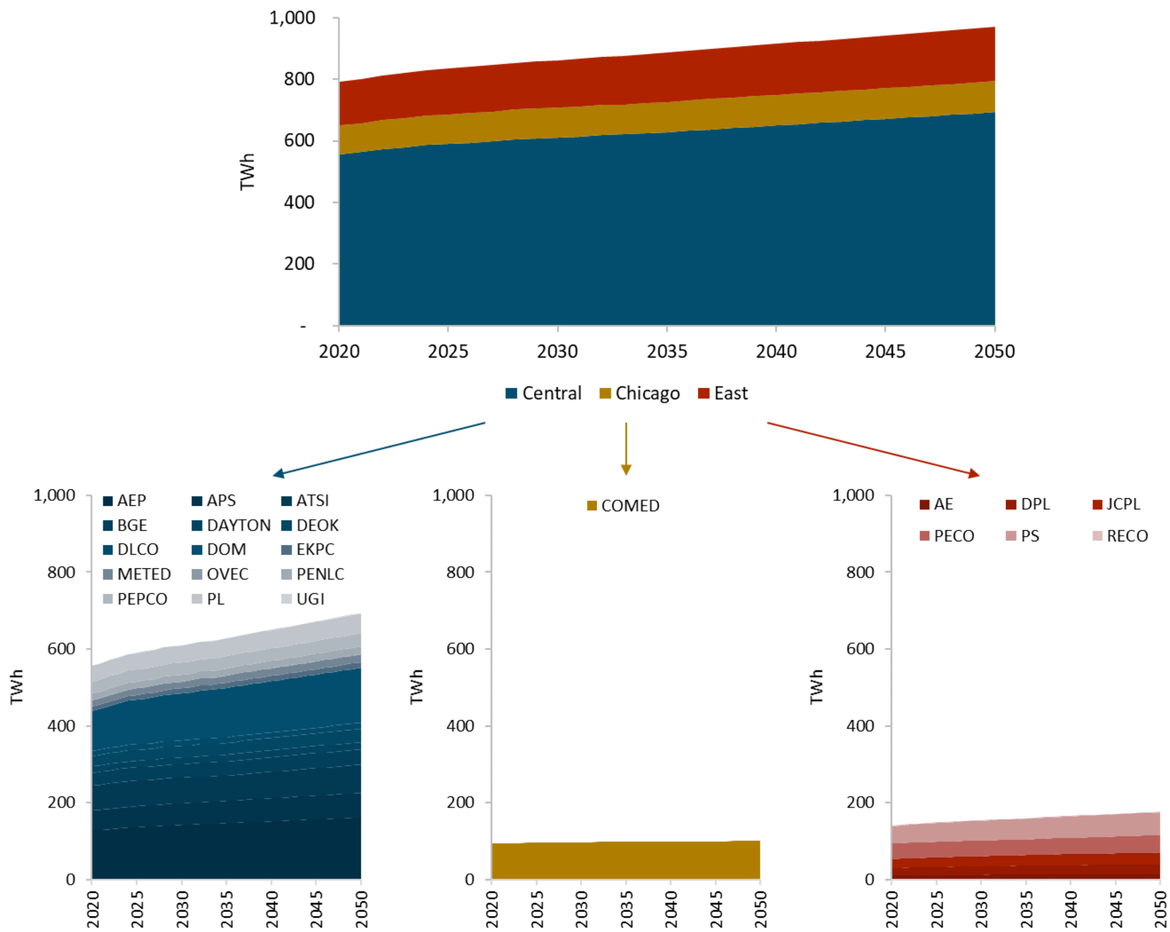
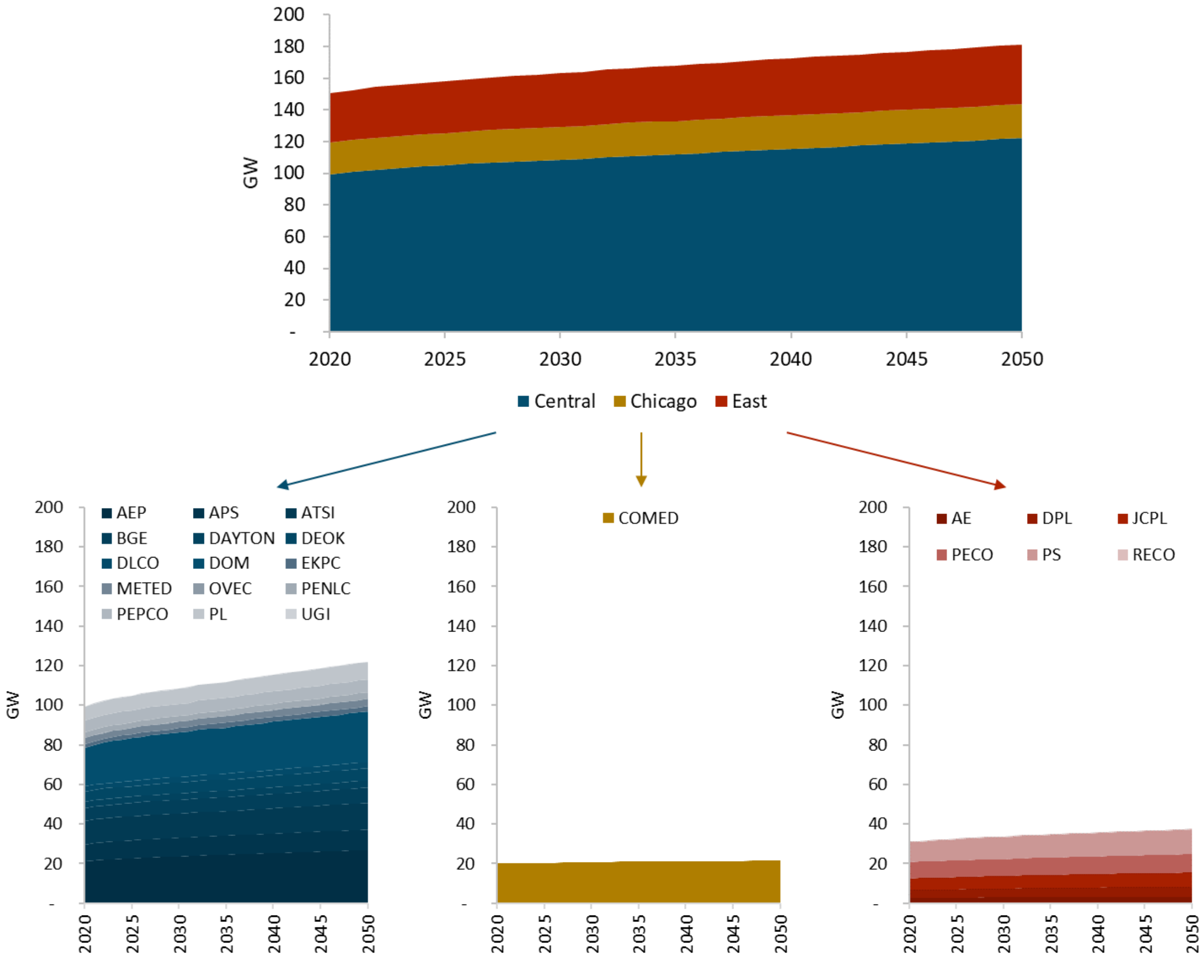


Figure 44. Annual Gross Peak Demand Forecasts for RESOLVE Zones (Central, Chicago, East) and Breakdown by Utility



Given the multi-decade time horizon modeled in this study, these load forecasts are invariably subject to uncertainties. For example, the shelter-in-place orders and economic disruptions associated with COVID-19 have reduced load by up to 5% to 10% at times in 2020. However, E3 does not speculate as to the future load impact of COVID-19 in this study, which is likely to be tangible over the next several months and years but minimal in the longer term.

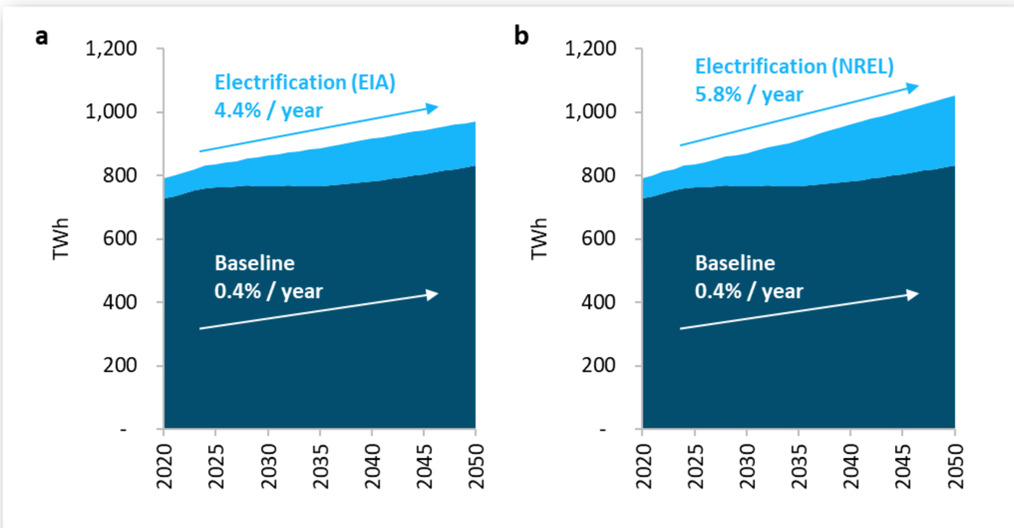
Another relevant variable for load forecasts is the level of electrification in other sectors of the economy as electric vehicles become more cost-competitive and states commit to more ambitious economy-wide decarbonization goals. In the current study, we assume that total gross loads forecasted by PJM include electrification loads from space and water heating in buildings, and light-duty and heavy-duty electric vehicle charging in the transportation sector. Electrification load assumptions are taken from the Reference scenario in E3's PATHWAYS model, which is developed based on the EIA Annual Energy Outlook.[25] Electrification loads assumed in our study are consistent with PJM's assumptions.[26] As can been seen in Figure 45(a), electrification loads estimated from the EIA assumptions indicate a

[25] Descriptions of E3's PATHWAYS model can be found here: https://www.ethree.com/tools/pathways-model/. PATHWAYS Reference scenario assumptions are consistent with assumptions on sales share and macro growth drivers in the EIA Annual Energy Outlook: https://www.eia.gov/outlooks/aeo/.

[26] Communication with the client.

growth rate of 4.4% per year, which is substantially more rapid than the growth rate in baseline (non-electrification) loads. Nevertheless, higher levels of electrification have been modeled in other studies. For example, the Medium Electrification scenario in the NREL Electrification Futures Study[27] is often considered a "middle-of-the-road," economically achievable electrification scenario by E3. As shown in Figure 45(b), electrification loads derived from this NREL scenario for PJM grow at 5.8% per year. This would imply an annual gross load of approximately 1,051 TWh in 2050, a 33% increase from 2020 levels. Another point of reference is a previous E3 study[28] that evaluated high electrification as a plausible low-cost, low-risk strategy for meeting economy-wide climate mitigation goals in California. In this study, electrification efforts across building, transportation, and industry sectors would cause loads to increase by at least 60% by 2050 compared to current levels. In comparison, annual gross load in 2050 modeled in the current study (with electrification assumptions based on the EIA is approximately 971 TWh, a 23% increase from 2020 levels.

Figure 45. Baseline Annual Energy Consumption and Electrification Loads Estimated Based on (a) the EIA Assumptions and (b) NREL Medium Electrification Scenario



Load forecasts used for RESOLVE modeling account for plug-in electric vehicle charging loads and distributed solar generation. Annual net energy forecasts, net peak forecasts, and distributed solar adjustments to peak are from the PJM Load Forecast Report. Contributions of distributed solar energy to gross energy are estimated using forecasts of distributed solar nameplate capacity[29] and capacity factors of distributed solar generation[30] for each zone. Distributed solar generation is modeled as a resource to meet load along with other generation and storage resources in RESOLVE.

[27] NREL Electrification Futures Study: https://www.nrel.gov/analysis/electrification-futures.html.

[28] *Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model.* California Energy Commission. Publication Number: CEC-500-2018-012. https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.

[29] Analysis performed by IHS Markit for PJM. See: *Distributed Solar Generation Update*, Load Analysis Subcommittee, December 3, 2019. https://pjm.com/-/media/committees-groups/subcommittees/las/20191203/20191203-item-03b-pjm-distributed-solar-generation-2020.ashx.

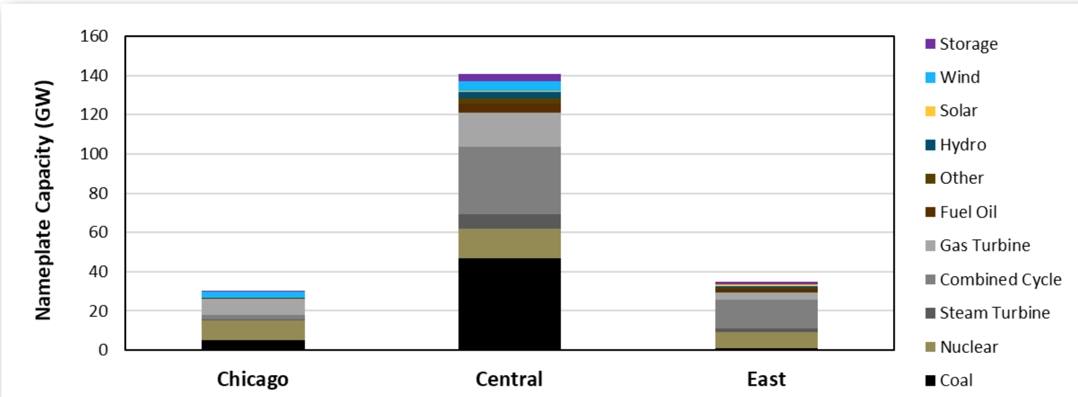
[30] Distributed solar generation profiles are produced using E3's renewable sampling methodology, highlighted in the appendix, which uses downloaded data from NREL's National Solar Radiation Database (NSRDB).

6.1.3 PJM System Existing and Planned Resources

PJM's current power supply is primarily comprised of thermal resources with minimal amounts of wind, solar, and storage. Natural gas generation makes up most of the thermal fleet, but a significant amount of coal and nuclear capacity also exists. In the next five years, PJM will see moderate renewable energy added to the system, but also a significant amount of additional gas capacity as developers take advantage of low shale gas prices in the region[31].

To prepare the unit-by-unit data for simulated operations in RESOLVE, the set of existing and planned PJM resources was aggregated strategically to allow for realistic dispatch and not compromise model run time.[32] Most of the PJM capacity (and load) exists in the Central zone, while the rest is split between the Chicago and East zones.

Figure 46. PJM 2020 Installed Capacity by Resource and RESOLVE Zone



RESOLVE's capacity expansion optimization can both invest in new resources and retire existing resources if it is economic to do so. Existing resource economics are modeled as a comparison of going-forward costs (i.e., fixed O&M, sustaining capex, etc.) and revenues based on marginal system prices. In cases where revenues cannot cover long-run, going-forward costs over the modeling period, resources are retired in favor of more economic alternatives. E3 estimated the going-forward costs for specific tiers of resources, such as older and newer nuclear plants or gas-fired steam turbines, based on plant-level data from S&P and public reports from the EIA and PJM Market Monitor. To avoid unrealistic retirement decisions, the pace of coal and nuclear retirements was limited based on recent historical retirement trends. Coal retirements were capped at an average of 4 GW per year through 2025 and then 6 GW per year through 2030. This acceleration reflects anticipated economic trends for coal as carbon emissions are seen as a financial risk and plants face impending environmental regulations, such as the Coal Combustion Residuals (CCR) ruling that may require compliance after the mid-2020s. These retirement rates track closely in the near term with the PJM historical average, which has been around 3 GW per year. While nuclear plants do not see the same retirement risk as coal in this study, a similar retirement constraint was applied to ensure realistic outcomes in outlier scenarios. For nuclear resources, the maximum pace of retirements was limited to 800 MW per year within each of the three model zones (Chicago, Central, East). This is equivalent to one large nuclear unit per year. Nuclear retirements in PJM have totaled approximately 300 MW per year on average in recent history. The values used within RESOLVE are slightly higher than historical rates because across the U.S., especially in Western Electricity Coordinating Council (WECC),

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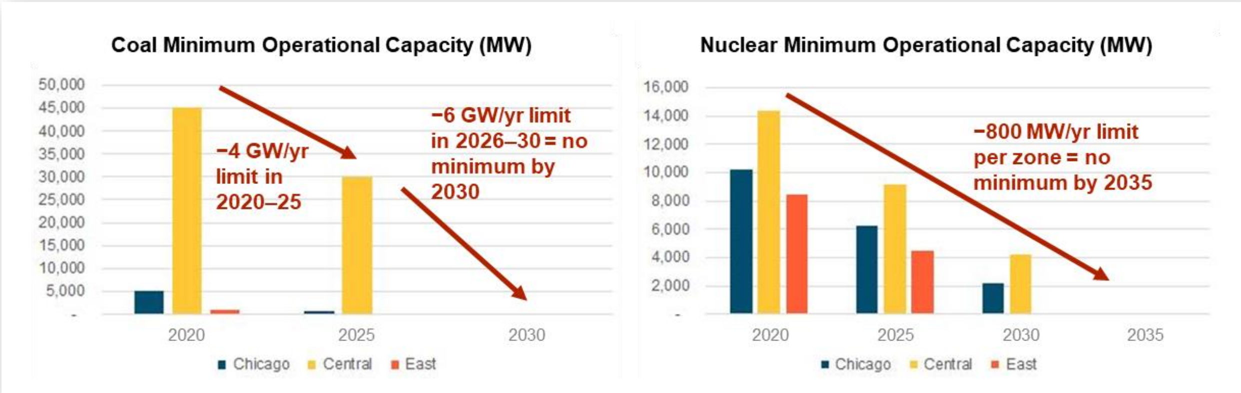
[31] Data for PJM's existing and planned resources was extracted from S&P Global Market Intelligence (SNL), which compiles generator information and queue data from public sources. Planned resources exclude those recently announced or in early development. Behind-the-meter solar capacity, modeled as a resource, was used from PJM's forecast.

[32] Coal and nuclear plants were split into groups based on ongoing fixed costs and whether the plant is eligible for a state subsidy, like the David-Besse nuclear power plant in Ohio. Combined cycles, gas turbines, and steam turbines were categorized by gas hub and then into tiers by heat rate. All were broken up into respective RESOLVE zones.

cheap gas and renewable prices have driven many coal plants and some nuclear plants to retire. Renewable development in PJM has lagged the Western States due to more conservative renewable targets, but given the low costs of both gas and renewables, a faster pace of retirements is plausible.

Figure 47. Coal and Nuclear Retirement Pace in PJM Assumed in RESOLVE



6.1.4 PJM System Future Resource Options

To model renewable energy resource options for future development, E3 relied on data from NREL's ReEDS model. NREL's ReEDS model employs a geographic mapping of renewable energy resource potential that aligns closely with current Balancing Authority Area territories to simulate electricity-sector investment decisions. Figure 48 shows this map, where resources are defined within a given "p-zone." NREL's ReEDS model data represents technical potentials; i.e., the maximum available amount of wind and solar capacity, for resources within each of these zones. Due to the enormous magnitude of the technical potential within each zone and limited relevance of inferior renewable resources unlikely to be developed, lower capacity factor (less than 25%) wind resources were excluded from the study. The total NREL technical potential for solar and wind resources considered in this study is illustrated in Figure 49, ranked in order of forecasted 2030 levelized costs.

Figure 48. NREL ReEDS Zonal Map

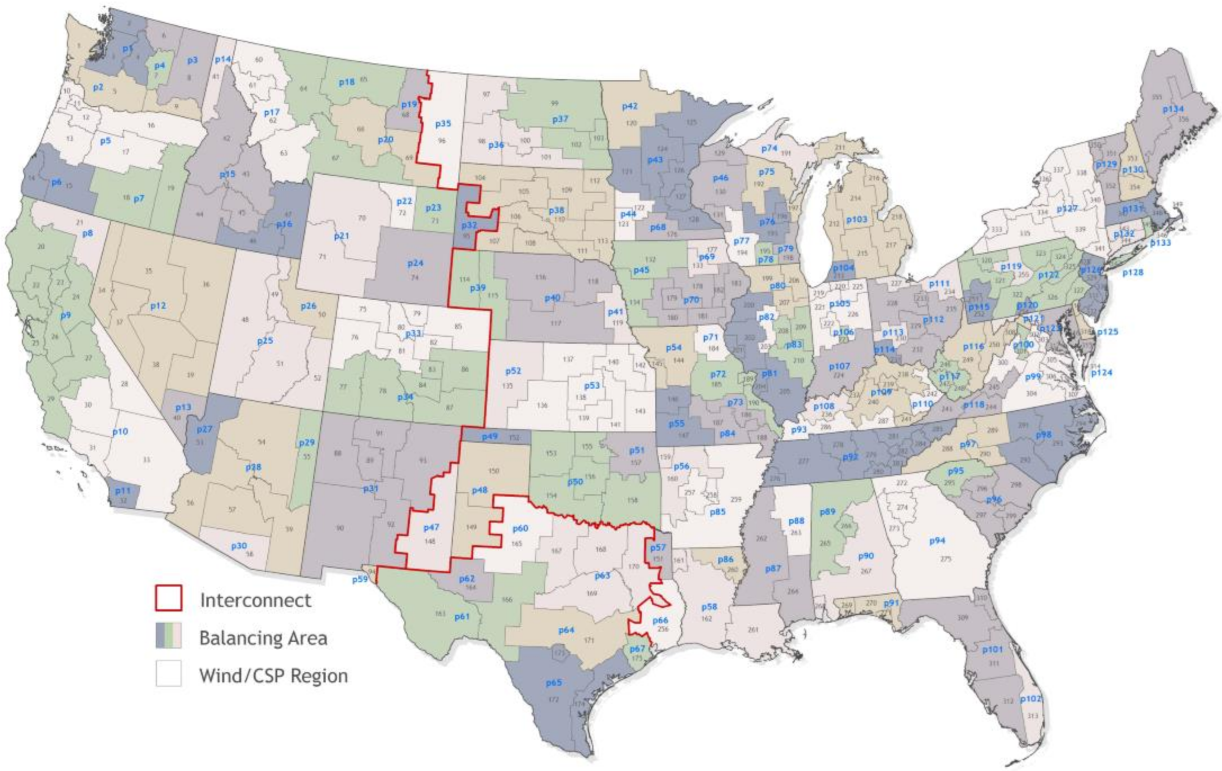
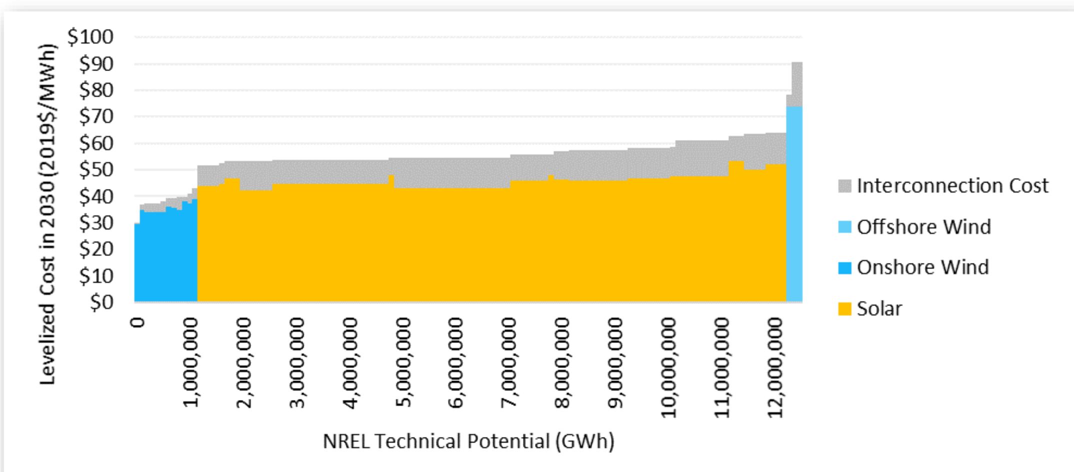


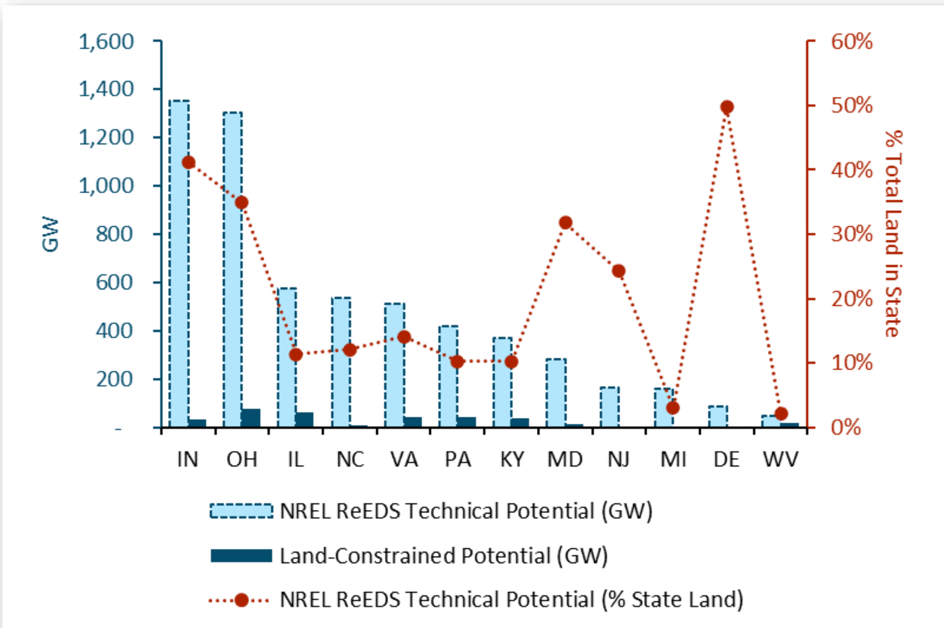
Figure 49. NREL ReEDS Unconstraint Technical Potential for PJM



The solar and wind capacity in NREL's ReEDS model represents all potential resources available for development after land-use screens that remove land area that is either protected or already developed (e.g., national parks or cities). However, NREL's total resource potential still far exceeds what can feasibly be developed simultaneously. To limit the RESOLVE model's utilization of technical resource potential to more politically and technically viable future land use patterns, E3 applied additional constraints to the total solar and onshore wind potential available in the model. In all core scenarios, E3 restricted land use for solar resources to 4% of farmland and land use for onshore wind resources to 4% of farmland and 2% of forest in each state, based on the portion of each state within the PJM transmission territory. To test the impacts of this land-use restriction, E3 modeled a sensitivity case wherein the full NREL's ReEDS technical potential for solar and onshore wind was available for development in RESOLVE, as well as an even more land-constrained case where the wind and solar potential used in the core set was halved. The results of this sensitivity are discussed in Section 4.4.1.

The NREL ReEDS technical potential and land-use-constrained potential for solar and onshore wind are compared in Figure 50 and Figure 51, respectively. The land use implied by the NREL ReEDS technical potential as a percentage of total land area in each state is also shown in Figure 50 and Figure 51. For both wind and solar resources, the land-use-constrained potential is substantially smaller than the total technical potential.[33]

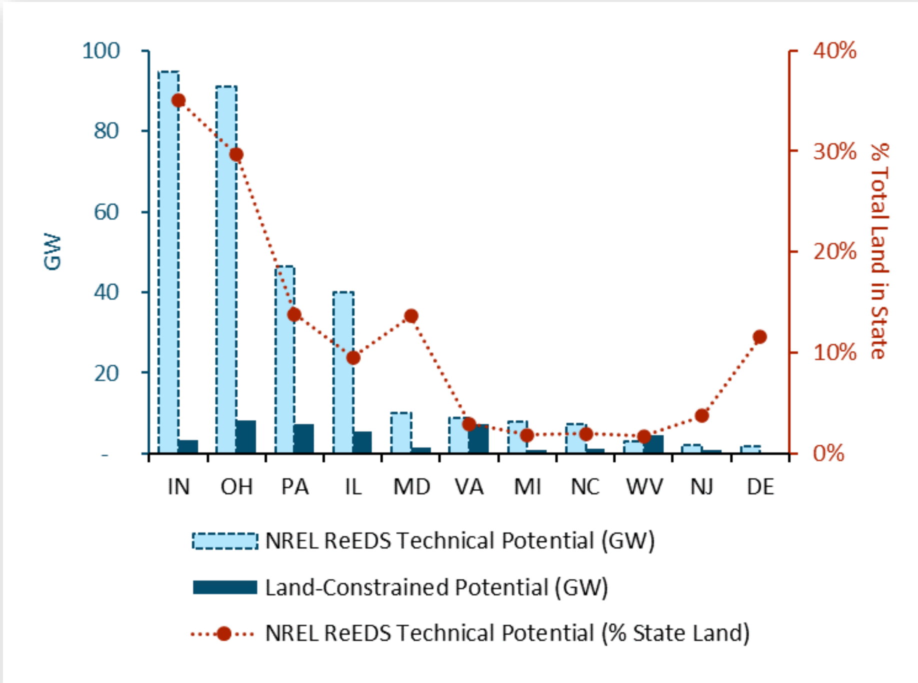
Figure 50. NREL ReEDS Technical Potential and Land-Use-Constrained Potential For Solar Resources by State in PJM[34]



[33] One exception is onshore wind in West Virginia, with the land-use-constrained potential slightly higher than the NREL technical potential. Nevertheless, the same fractional land use constraints were applied for all states for consistency.

[34] Land-constrained solar potential for NC, NJ, MI, and DE appear to be zero due to scaling. In reality, these values are nonzero, albeit small in comparison with the NREL ReEDS technical potential.

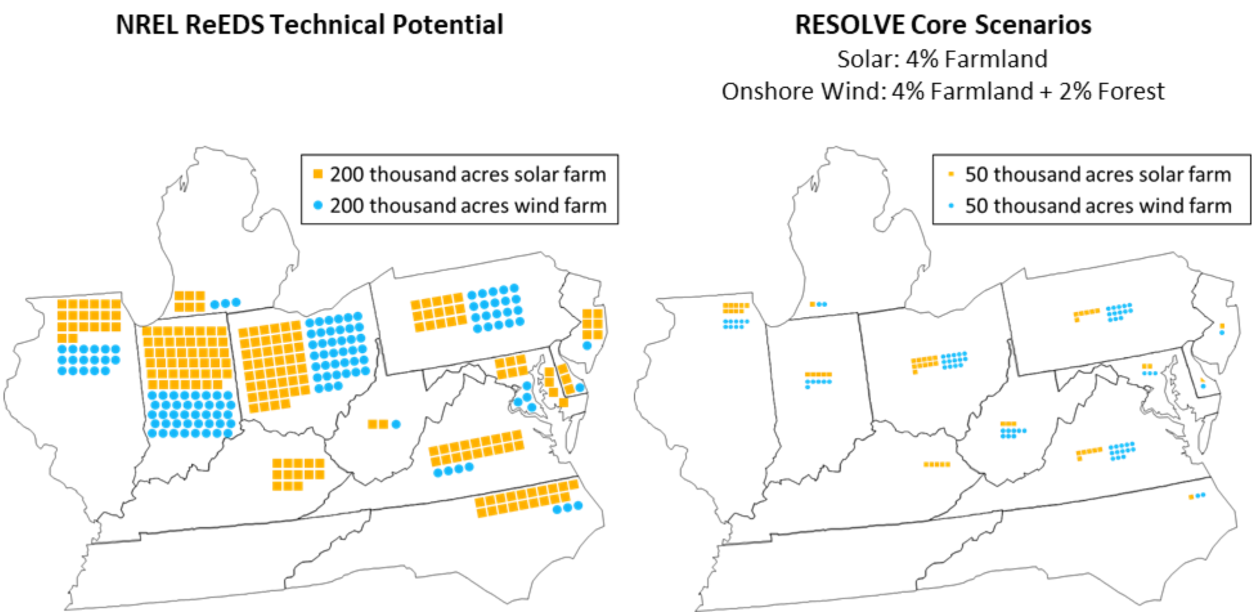
Figure 51. NREL ReEDS Technical Potential and Land-Use-Constrained Potential for Onshore Wind Resources by State in PJM



To put the resource potentials above in further in context, land areas implied from the NREL ReEDS technical potential and E3's core scenario resource potential assumptions are compared in Figure 52. Land areas in Figure 52 are estimated by assuming 7 acres of land use per MW of capacity for utility-scale solar, and 85 acres of land use per MW of capacity for onshore wind (including indirect land use).[35] Each full symbol (square or circle) in Figure 52 represents approximately two hundred thousand acres of land (roughly 809 km^2) in the case of NREL ReEDS technical potential (left figure) and approximately fifty thousand acres of land (roughly 202 km^2), in the case of RESOLVE core scenarios (right figure). Note that symbols are not to scale or indicative of site location.

[35] Land use assumptions based on: (1) NREL Annual Technology Baseline 2017, "Land-Based Wind Power Plants." https://atb.nrel.gov/electricity/2017/index.html?t=lw. (2) NREL Regional Energy Deployment System (ReEDS) Model Documentation: Version 2018. https://www.nrel.gov/docs/fy19osti/72023.pdf.

Figure 52. Land Use of Solar and Onshore Wind Implied from NREL ReEDS Technical Potential and RESOLVE Core Scenarios[36]

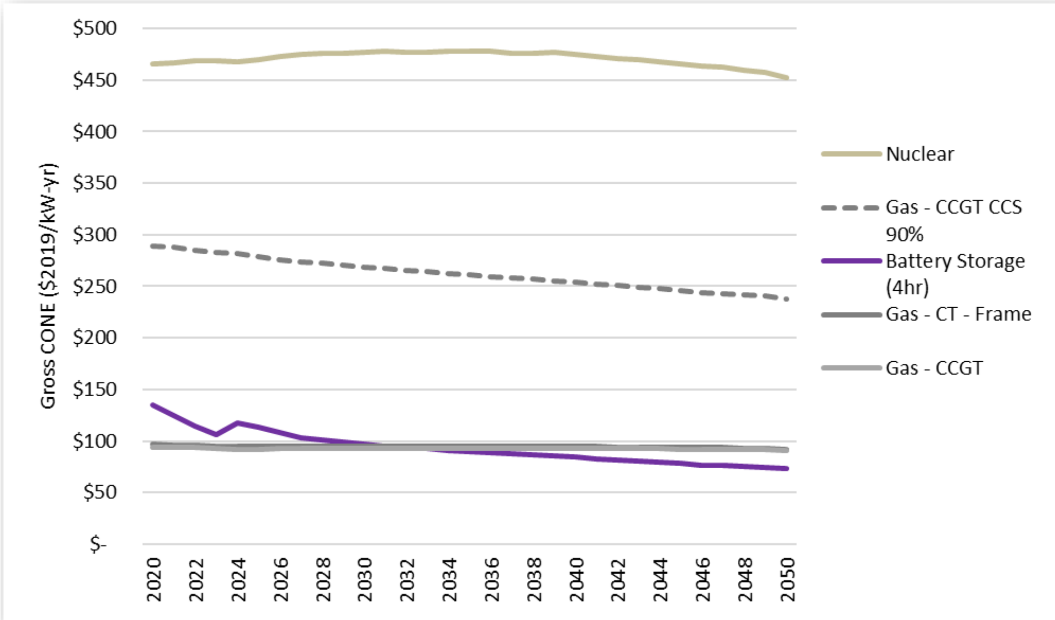


To model future costs associated with new resources, E3 relied on input data from NREL ReEDS as well as cost assumptions from NREL's 2109 Annual Technology Baseline (ATB) and Lazard's 2019 Levelized Cost of Storage report. All costs are provided in real 2019 dollars.

Figure 53 illustrates the resulting levelized cost of new entry (CONE) forecasts for conventional resources and 4-hour battery storage. The battery storage, gas combined cycle (CCGT), and gas combustion turbine (CT) technologies are all resources that RESOLVE can select for future development within the core set of modeling scenarios. Nuclear and gas CCGTs with 90% CCS are technologies that are made available to RESOLVE in sensitivity cases. All of these resources are available for the model to select, in addition to the solar and wind resources discussed above.

[36] Onshore wind potential for Kentucky shows as zero, as Kentucky wind was not modeled in RESOLVE due to its low capacity factor (< 35%) compared to other locations in PJM.

Figure 53. Gross CONE for Non-Renewable Resource Technologies[37]

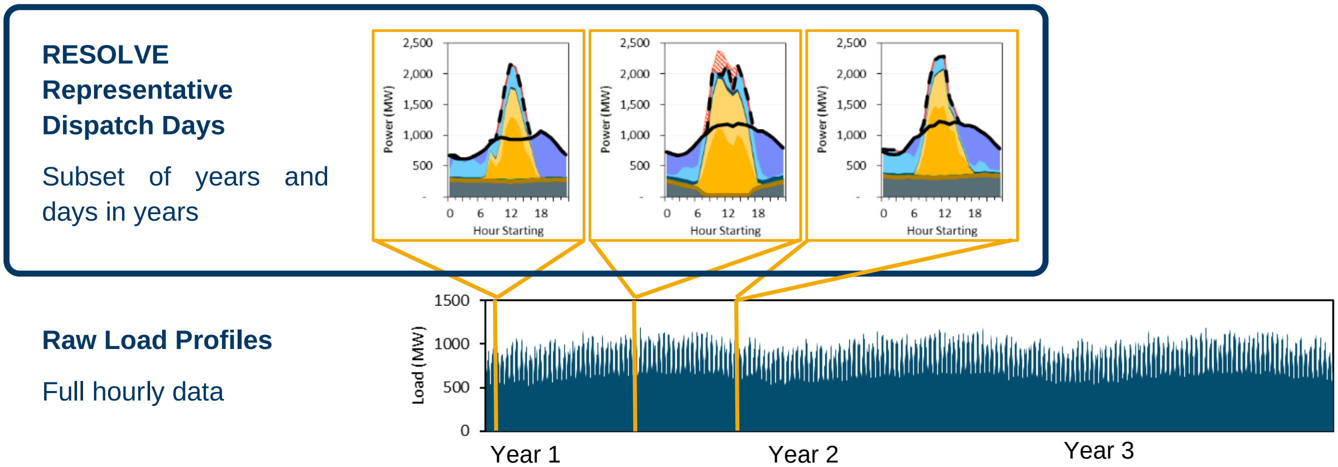


6.1.5 PJM System Hourly Profiles

Producing hourly energy generation profiles that reflect realistic system conditions is crucial for planning a future system that is resilient to intermittent renewable resources. Load, wind, and solar vary on an hourly, daily, and seasonal basis, and their variations are often correlated due to underlying meteorological phenomena that affect all three. To ensure these patterns are reflected in the set of representative days used in RESOLVE, historical hourly data for up to ten years was gathered and used as inputs to the E3 Day Sampling Algorithm. This algorithm, described in further detail in Appendix 7.3, selects a subset of days that best represents the full dataset. Thus, each RESOLVE day is based on an actual day seen in the past.

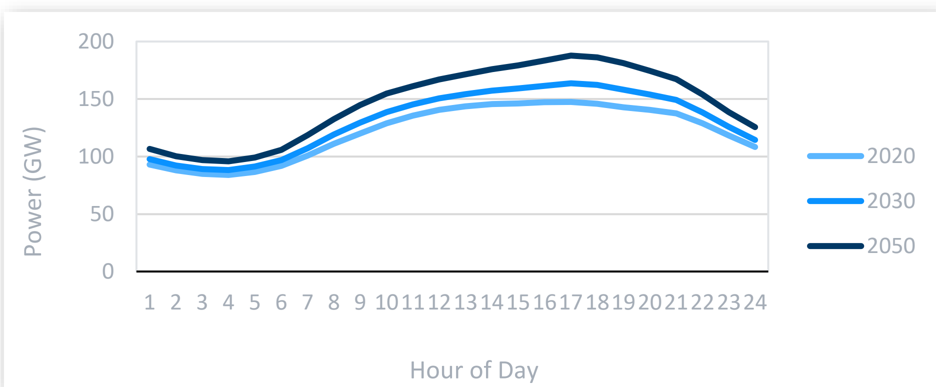
[37] Costs for battery storage include ITC benefits, the step up in cost 2024 represents the cost of battery storage that can no longer qualify for ITC after 2024

Figure 54. Illustrative Diagram of RESOLVE Representative Day Selection



Hourly load data was gathered from PJM's website for 2007 to 2017. This data, reported by LSE, was aggregated by RESOLVE model zone and normalized to annual energy, to account for load growth from year to year. This assumes that the underlying load shape stays similar from year to year. To account for growth in electrification loads (electric heat pumps, water heaters, and vehicles), which tend to have profiles that look different than the underlying load shape, normalized profiles were gathered from the E3 PATHWAYS model[38]. This ensures that as these technologies are more abundant in the future, the total load shape on each RESOLVE day changes meaningfully from year to year.

Figure 55. Peak Day Hourly Load Shape and Magnitude Changes Across Modeled Years

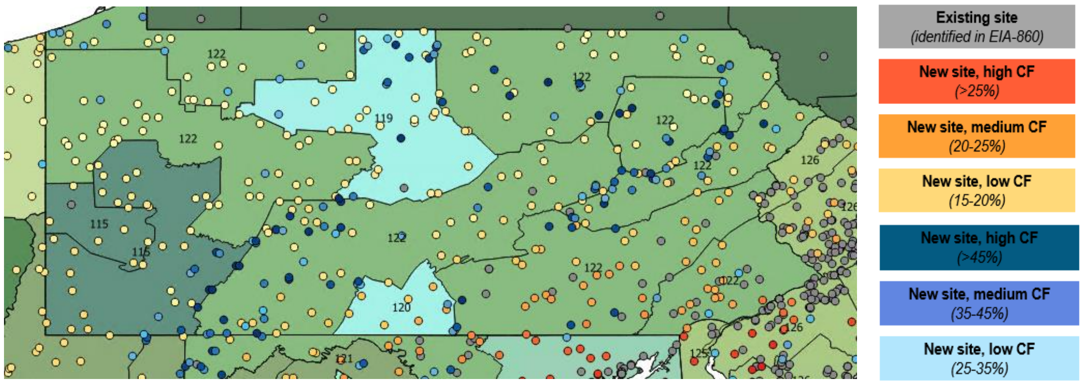


Hourly solar and wind data from 2010 to 2012 was gathered from NREL's National Solar Radiation Database (NSRDB) and Wind Toolkit (WTK), respectively. Profiles were simulated based on actual solar irradiance and wind speed data from these sources for both existing and candidate resources. The EIA has useful data for existing solar and wind plants across the US, such as coordinates, capacity, and other useful resource-specific parameters (tilt angle, azimuth, and fixed vs tracking indicators for solar and hub height and turbine type for wind). This data was used to produce aggregated existing solar and wind profiles for each RESOLVE zone. Behind-the-meter (BTM) solar data is not available from the EIA; but because this resource is prevalent in densely populated regions, coordinates around each major city

[38] The E3 Pathways model is a stock rollover model used for economy-wide decarbonization studies and relies on accurate representation of electrification loads. Profiles for these loads are produced using various weather data and technology simulations and simulated driving profiles based on actual data.

were sampled for these profiles. To produce the candidate resource profiles, state-of-the-art resource-specific inputs were used at coordinates scattered within the NREL ReEDS regions discussed in the previous section. These points were categorized by capacity factor, so each candidate resource modeled receives a unique profile.

Figure 56. Example of Sampled Wind (Blue) and Solar (Yellow/Red) Points Used for Future Resource Profiles in PA



6.1.6 PJM System Fuel Costs

Fuel price assumptions for gas, nuclear, and coal resources were produced using market-based data and other central price forecast sources. For each gas price hub in PJM, the OTC Global Holdings monthly forward prices were used in the near term and a historical basis spread between each gas hub and Henry Hub is applied to the EIA future Henry Hub prices in the long term. Coal and uranium price forecasts were based on data from the S&P Global Market Intelligence platform. One regional coal price forecast was used for each RESOLVE zone, as Illinois Coal Basin prices differ slightly from those in Appalachia, and one uranium price forecast was used for all PJM nuclear resources. These prices tend to be less volatile than gas prices across months and years, hence the steady trajectory in Figure 57 and Figure 58.

Figure 57. Coal and Uranium Price Forecast (Left) and Gas Price Forecast by Hub (Right)

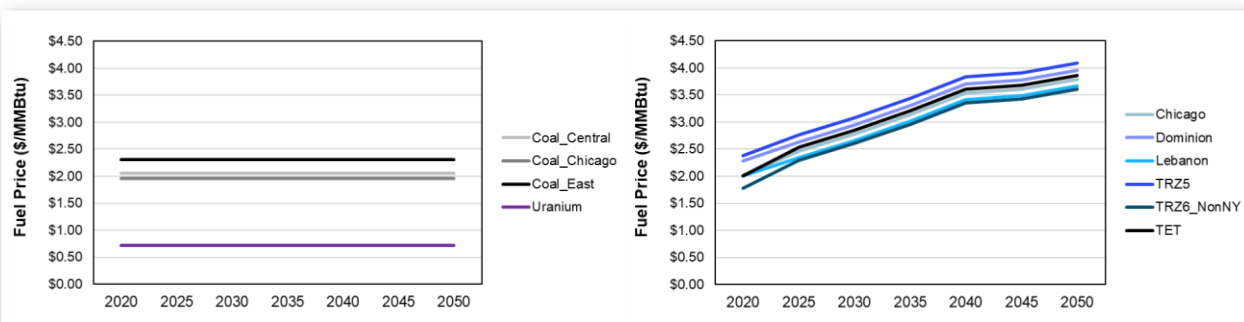
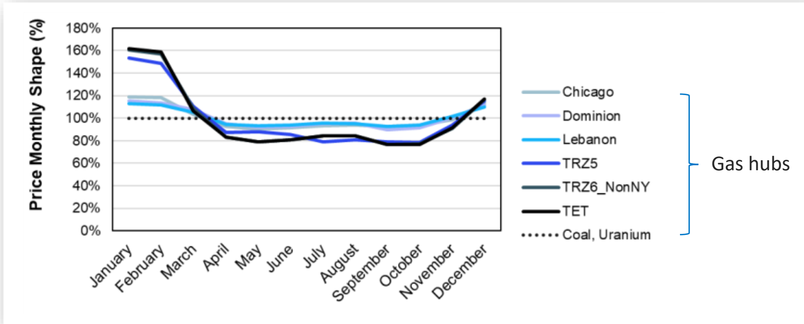


Figure 58. Monthly Price Shape by Resource



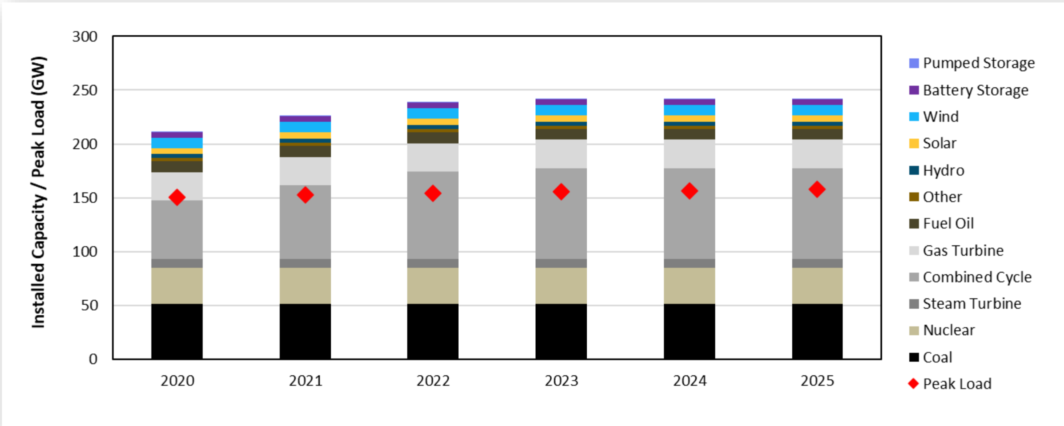
6.1.7 Reliability Contributions of Resources

Power systems are designed to have sufficient generation capacity to reliably serve load on the infrequent days with the highest peak demand. Reliability standards typically require planning for enough power supply such that a loss of load event, signifying insufficient supply to match demand, occurs once every 10 years. This typically means holding extra generation capacity ranging from 10%-20% of the median system peak demand. This percentage of extra capacity is known as the PRM. For PJM, their convention for PRM is called the Installed Reserve Margin (IRM), which is around 15%[39]. After accounting for forced outages, as is done in RESOLVE, the target PRM used in this study was 9%.

In total, there is over 183 GW of nameplate thermal capacity (173 GW of effective capacity) on the PJM system, which has a peak demand of 150 GW forecasted for 2020. PJM's current reserve margin is approximately 30%, even though the target IRM is 15%, which suggests that the system has surplus capacity today above and beyond reliability requirements. Despite the system being capacity-long, there is currently 33 GW of new gas capacity expected to enter the market by 2025. This state of excess supply leads to significant retirements of the most-costly, least-utilized resources in PJM over the next decade in E3's model.

[39] PJM's reliability accounting metrics and methodology are converted to RESOLVE's convention from the PJM Reserve Requirement Study https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx

Figure 59. PJM Installed Capacity by Resource Type (2020–2025)



All generation resources contribute some amount of capacity to system peak demand. This amount is often known as net qualifying capacity (NQC), which is a resource's capacity adjusted based on measurements of historical peak performances of a given technology.

In theory, conventional units could contribute 100% of their capacity to meet peak demand, as these technologies can operate flexibly and ramp up to full capacity whenever they are needed. In reality, conventional units are not always available whenever the power system needs them to be – they may be experiencing a forced outage or down for maintenance. For this reason, thermal units are "derated" slightly from their maximum nameplate capacity when calculating their capacity contribution to meeting the PRM. The resulting NQC values assumed for thermal resource within the RESOLVE model were obtained from PJM data that indicated how often the units were typically available over the year[40].

Renewable resource contributions are not as straightforward to quantify as for thermal generators. Renewable resources vary constantly in output and cannot be dispatched flexibly to meet load in any hour like a conventional thermal power plant. For this reason, the NQC of renewable resources must be calculated based on their expected output during the hours of peak demand each year. This calculation identifies the Effective Load Carrying Capability (ELCC) used to quantify the contribution of renewables to a PRM.

ELCC calculations are multi-dimensional and complex. A resource class can cannibalize its own ability to serve peak demand as more of it connects to the grid, and other resources can either complement or detract from a resource's ELCC value. For example, Figure 60 illustrates how adding more and more solar photovoltaics (PV) to a system offers a diminishing impact on the remaining peak demand. As more solar is introduced onto the system, the peak is both reduced and shifted later in the day. Since solar only generates energy during daylight hours, the ability of solar to serve system peak loads diminishes and eventually reaches zero at high levels of solar penetration as the remaining "net peak" shifts to non-daylight hours.

[40] The PJM Manual 20 contains forced outage rates and reliability metrics for different categories of generators, which was used as NQC for the RESOLVE model https://www.pjm.com/~/media/documents/manuals/m20.ashx

Figure 60. Diminishing Marginal Peak Load Impact of Solar PV

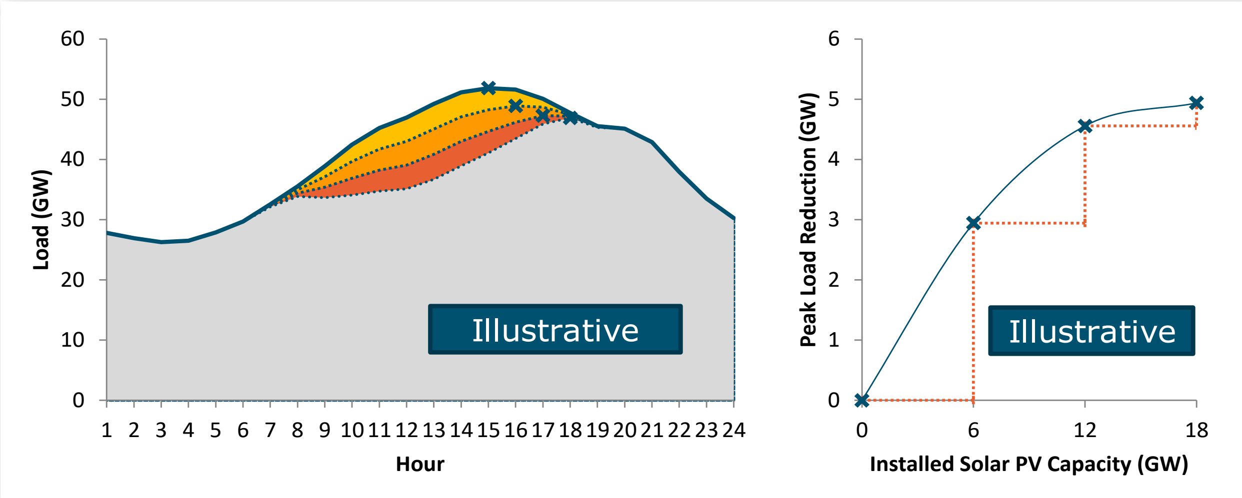
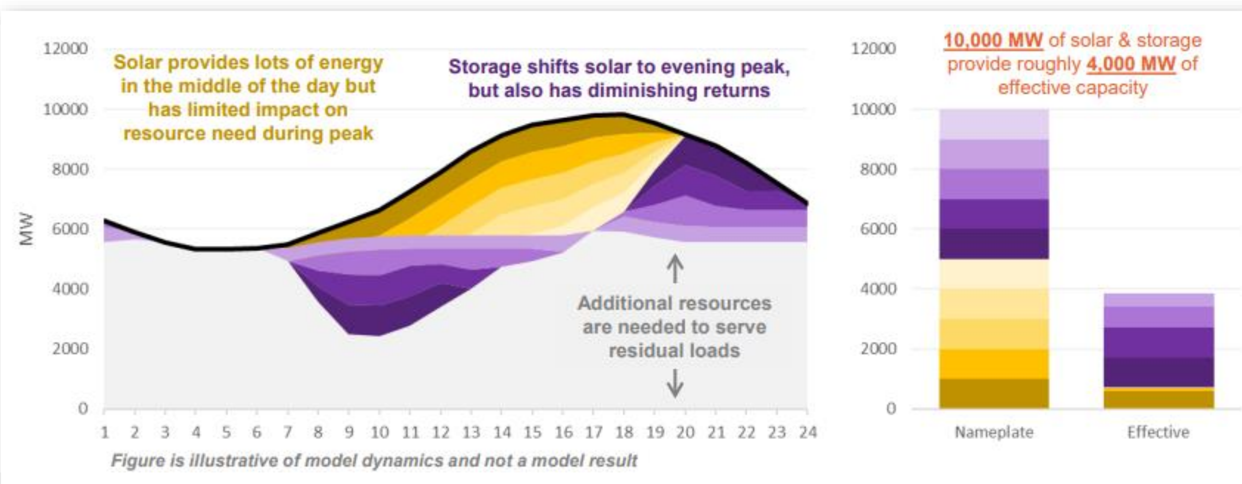


Figure 61 helps to illustrate the complimentary nature, and limits, of solar and energy storage for serving peak load. Storage can help shift solar generation to peak hours by charging early in the day in off-peak hours and then discharging during evening hours after solar output declines. However, storage is energy limited and thus not a firm resource. It can only contribute to reducing demand by as much as it can charge and then discharge. As more storage is added to the grid, the demand profile net of battery operations becomes flatter and flatter, diminishing the effect of storage on reducing peak demand. For example, if four-hour battery resources are continually added to a system and used to serve peak demand, then eventually the remaining net load profile will flatten to a peak that lasts longer than four hours. At that point, four-hour batteries would only be able to serve a fraction of peak hours. Energy storage resource would thus require a longer duration reservoir to continue to deserve full ELCC credit. Wind resources present a similar phenomenon of diminishing ELCC at higher penetrations, though not as dramatic as for solar and storage.

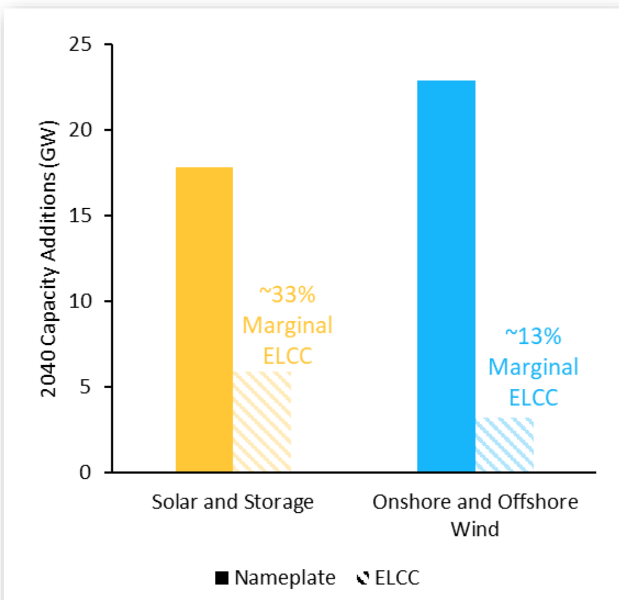
Figure 61. Storage Capacity Value and Complimentary Nature with Solar



The PJM RESOLVE model in this study featured renewable energy and battery storage ELCC assumptions tailored to the specific hourly load and renewable resource profiles of the PJM region. This allowed RESOLVE to select the economically optimal combination of solar, wind, and energy storage to maximize the collective contribution to PJM's peak demand.

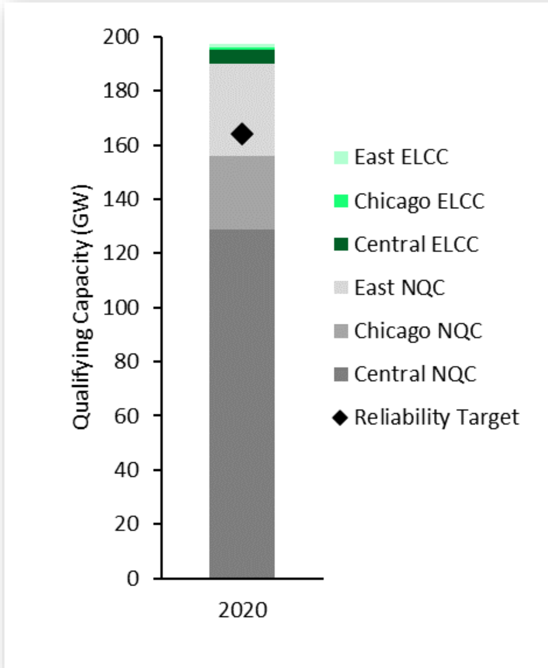
The PJM ELCC assumptions developed for this study were calculated using an ELCC proxy method, whereby amounts of renewable resources were added to a multi-year hourly PJM load profile and then a battery resource logic was applied to the net load in order to obtain a charge and discharge profile. This approach was run for different levels of each renewable resource and sizes of battery storage. The peak reduction effect of the renewables and the battery storage were analyzed for the top 100 hours of demand over three years. This calculation was performed for the individual zones within the RESOLVE model to create incremental ELCC curves specific to each zone. Incremental ELCC curves provide marginal ELCCs for discrete stepwise additions of a given resource. These curves were then used to create two multi-dimensional "ELCC surfaces." In the case of this study, a solar-storage surface and an onshore-offshore wind surface were implemented. These surfaces calculate the combined ELCC of the two resources, which allows the model to capture the synergistic effects of resource with one another and to capture how one resource affects the ELCC of another as discussed above. Figure 62 highlights how drastically the capacity contributions of renewables and diminish as more and more of these resources are connected to the grid. This figure are a snapshot of the capacity additions from 2035 to 2040 in a case with high penetrations of renewables and illustrate how much dependable capacity, or NQC, the additional renewable resources contribute towards ensuring PJM can meet its annual peak load.

Figure 62. 2040 Total PJM Solar + Storage and Onshore + Offshore Wind Capacity Addition Comparison of Nameplate and ELCC Contribution



To calculate the total capacity available for meeting the PRM, E3's RESOLVE model sums the total NQC values for thermal resources and ELCC value for renewables and storage. Figure 63 shows that the 2020 system reliability target is met, and significantly exceeded, with existing resources within PJM based on their NQCs and/or ELCC.

Figure 63. PJM-Wide PRM Reliability Target and Qualifying Capacity of Existing Resources in 2020



7 Appendix B: RESOLVE Model Documentation

7.1 Overview

RESOLVE is a resource investment model that uses linear programming to identify optimal long-term generation and transmission investments in an electric system, subject to reliability, technical, and policy constraints. Designed specifically to address the capacity expansion questions for systems seeking to integrate large quantities of variable resources, RESOLVE layers capacity expansion logic on top of a production cost model to determine the least-cost investment plan, accounting for both the up-front capital costs of new resources and the variable costs to operate the grid reliably over time. In an environment in which most new investments in the electric system have fixed costs significantly larger than their variable operating costs, this type of model provides a strong foundation to identify potential investment benefits associated with alternative scenarios. RESOLVE's optimization capabilities allow it to select from among a wide range of potential new resources. In general, the options for new investments considered in this study are limited to those technologies that are commercially available today, with sensitivities around emerging technologies, such as carbon capture and small modular nuclear reactors. This approach ensures that the greenhouse gas reduction portfolios developed in this study can be achieved without relying on assumed future technological breakthroughs. This modeling choice is not meant to suggest that such emerging technologies should not have a role in meeting regional greenhouse gas reduction goals, but instead reflects a simplifying assumption made in this study.

7.2 Operational Simulation

To identify optimal investments in the electric sector, maintaining a robust representation of prospective resources' impact on system operations is fundamental to ensuring that the value each resource provides to the system is captured accurately. At the same time, the addition of investment decisions across multiple periods to a traditional unit commitment problem increases its computational complexity significantly. RESOLVE's simulation of operations has therefore been carefully designed to simplify a traditional unit commitment problem, where possible, while maintaining a level of detail sufficient to provide a reasonable valuation of potential new resources. The key attributes of RESOLVE's operational simulation are enumerated below:

+ Hourly chronological simulation: RESOLVE's representation of system operations uses an hourly resolution to capture the intraday variability of load and renewable generation. This level of resolution is necessary in a planning-level study to capture the intermittency of potential new wind and solar resources, which are not available at all times of day to meet demand and must be supplemented with other resources.
+ Aggregated generation classes: Rather than modeling each generator within the study footprint independently, generators in each region are grouped together into categories with other plants whose operational characteristics are similar (e.g. nuclear, coal, gas combined cycle, gas combustion turbine). Grouping like plants together for the purpose of simulation reduces the computational complexity of the problem without significantly impacting the underlying economics of power system operations.
+ Linearized unit commitment: RESOLVE includes a linear version of a traditional production simulation model. In RESOLVE's implementation, this means that the commitment variable for each class of generators is a continuous variable rather than an integer variable. Additional constraints on operations (e.g., Pmin, Pmax, ramp rate limits, minimum up and down time) further limit the flexibility of each class' operations.

- **Zonal transmission topology:** RESOLVE uses a zonal transmission topology to simulate flows among the regions represented in the analysis as model zones. In this study RESOLVE includes three zones: Chicago (ComEd), Central (RTO), and East (EMAAC).

- **Co-optimization of energy and ancillary services:** RESOLVE dispatches generation to meet load across the modeled regions, while simultaneous reserving flexible capacity to meet the contingency and flexibility reserve needs. As systems become increasingly constrained on flexibility, the inclusion of ancillary service needs in the dispatch problem is necessary to ensure a reasonable dispatch of resources that can serve load reliably.

- **Smart sampling of days:** Whereas production cost models are commonly used to simulate an entire calendar year (or multiple years) of operations, RESOLVE simulates the operations of the modeled system for 30 sampled days. Load, wind, and solar profiles for these selected days, sampled from the historical meteorological record over a specified period, are selected and assigned weights so that, taken in aggregate, they produce a reasonable representation of complete distributions of potential conditions[41]. This allows RESOLVE to approximate annual operating costs and dynamics while simulating operations for only the selected days. In this study, a sample of 30 days is used, based on historical meteorological record from 2010 to 2012.

- **Hydro dispatch informed by historical operations:** RESOLVE captures the inherent limitations of the generation capability of the hydroelectric system by deriving constraints from actual operational data. Three types of constraints govern the operation of the hydro fleet as a whole: (1) daily energy budgets, which limit the amount of hydro generation in a day; (2) maximum and minimum hydro generation levels, which constrain the hourly hydro generation; and (3) maximum multi-hour ramp rates, which limit the rate at which the output of the collective hydro system can change its output across periods from one to four hours. Collectively, these constraints limit the generation of the hydro fleet to reflect seasonal limits on water availability, downstream flow requirements, and non-power factors that impact the operations of the hydro system. The derivation of these constraints from actual hourly operations makes this representation of hydro operations conservative with respect to the amount of potential flexibility in the resource; however, hydro is a rather small portion of the total PJM fleet installed capacity.

7.3 RESOLVE Day Sampling

Computation can be challenging for a model like RESOLVE that makes both investment and operational decisions across a long period of time. To alleviate this challenge, instead of simulating the system operation for an entire year, a subset of days is modeled to approximate the annual operating costs. In order to approximate the annual system operating costs while simulating only a subset of the number of days in a year, RESOLVE relies on a pre-processing sampling algorithm to select a combination of days whose characteristics are, together, representative of the conditions experienced by an electricity system over the course of multiple years. This pre-processing step uses optimization to sample a subset of conditions that, when taken in aggregate and weighted appropriately, provide a reasonable representation of the breadth of load, wind, and solar conditions observed in the historical record. A multi-objective optimization model is used to pick a set of days (and associated weights) to match historical conditions for

[41] An optimization algorithm is used to select the days and identify the weight for each day such that distributions of load, net load, wind, and solar generation match long-run distributions. For further detail on the smart sampling algorithm used in RESOLVE, see RESOLVE Day Sampling

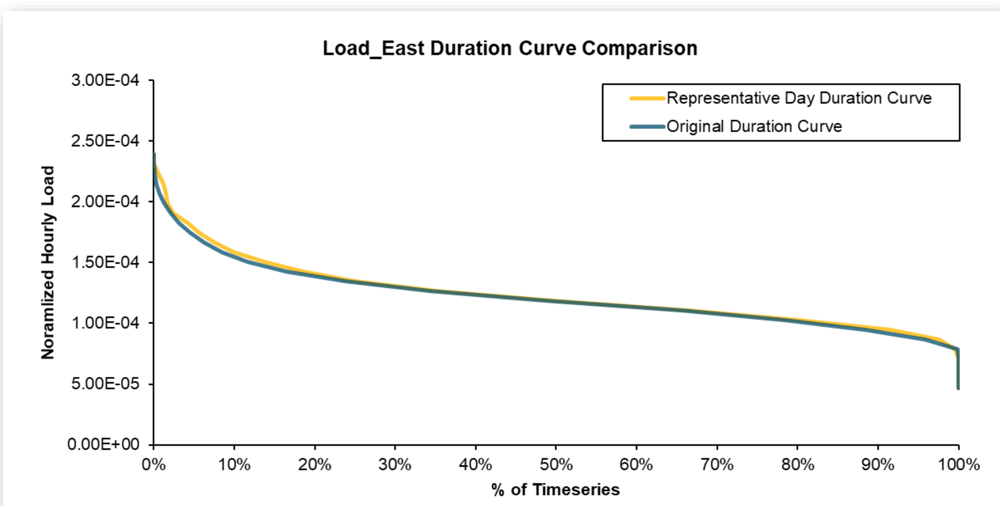
key indicators while also minimizing the number of days selected. The process for selecting the set of representative days follows several steps:

1. **The candidate pool of days is created**: Load, wind, and solar profiles are sampled from historical timeseries data as a representative sample of shapes. Load data was gathered from PJM's website, while wind and solar data were sampled from NREL's WTK and NSRDB, respectively. Wind and solar profiles were generated for existing sites using the EIA location and resource-specific data, and potential sites using E3's new profile sampling algorithm, which produces three tiers of candidate profiles within each NREL ReEDS zone.

2. **Key variables are selected**: Key variables are selected as indicators for system conditions. In this study, the variables used to characterize the representation of a sample include: (1) distributions of hourly load, wind and solar production; and (2) 2030 and 2045 hypothetical net load (assuming varying levels of solar and wind capacity); and (3) "month-day type" classification (i.e., January-weekday). These variables can also be weighted differently, which allows the optimization model to prioritize the more important variables with higher weights when matching the distribution. This study prioritizes fit on the distributions for future load, wind, solar, and net load conditions, as these factors have a significant effect on the operations of the electric system.

3. **Optimization model selects an optimal set of days**: From the candidate pool of days established in the first step, the optimization selects a set of days while minimizing the absolute errors for each of the criteria. If optional day types have been assigned by the user, the day selection algorithm will attempt to select at least one of each day type in the final sample. In this case, the day type was defined as "month-day type" (i.e., January-weekday) with some days denoted as a peak day. The output from the optimization algorithm includes a set of days, as well as associated weights through which those days may be weighted to represent a historic average year. An optimization model is used in the day sampling process. As shown in Figure 64 below, one component of the minimization is the alignment between historical and sampled hourly load distributions. The distribution of historical hourly load is plotted as the blue line in the chart, and the model selects and weights a subset of days to match the historical distributions (line shown in yellow).

Figure 64. Normalized Load Duration Curve Comparison Between Historical Data and Sampled Days for East Zone



The mathematical formulation to minimize absolute error is show below:

Table 8. Descriptions of Parameters Used in Day Sampling Algorithm

Model Component	Description
$\boldsymbol{Bins}$	Set of histogram bins for each criterion
$\boldsymbol{Days}$	Set of days in criteria timeseries
$\boldsymbol{OverallFreq_b}$	Frequency of bin across entire timeseries
$\boldsymbol{DailyFreq_{d,b}}$	Frequency of bin in each day
$\boldsymbol{NumDays}$	Number of days to select
$\boldsymbol{Importance_b}$	Relative importance of reducing absolute error of criteria bin
$\boldsymbol{selected_d}$	Indicator variable that the day has been selected
$\boldsymbol{weight_d}$	Normalized weight for each day
$\boldsymbol{selected_d}$	Indicator variable that the day has been selected

Equation 1 Optimization used in Day Sampling Algorithm

$$\text{min: } \sum_{b \in Bins} Importance_b \left| OverallFreq_b - \sum_{d \in Days} \left(weight_d \times DailyFreq_{d,b} \right) \right|$$

subject to:

$$\sum_{d \in Days} weight_d = 1$$

$$weight_d \leq selected_d \qquad \forall d \in Days$$

$$\sum_{d \in Days} selected_d = NumDays$$

The day sampling process yielded a set of days that show very small deviations from the historical distributions. The details for each of these days—the calendar days used for load, wind, and solar, and the associated weight attributed to the day—are shown in Table 9.

Table 9. Set of RESOLVE Days Selected by the Day Sampling Algorithm

Model Day	Scaled Annual Weights	Month	Day Tag
1	19.443	11	November-weekday
2	18.988	8	August-weekend
3	17.035	1	January-weekday
4	16.631	9	September-weekday
5	16.590	4	April-weekday
6	15.601	6	June-weekday
7	15.009	4	April-weekday
8	14.937	12	December-weekend
9	14.506	3	March-weekday
10	14.391	10	October-weekday
11	14.377	6	June-weekend
12	14.283	7	July-weekday
13	13.573	1	January-weekday
14	13.456	7	Peakday
15	13.346	9	September-weekend
16	13.251	7	July-weekend
17	12.963	3	March-weekday
18	12.781	8	August-weekday
19	12.164	2	February-weekday
20	11.467	2	February-weekend
21	10.620	5	May-weekend
22	10.535	11	November-weekend
23	10.206	10	October-weekday
24	9.279	5	May-weekday
25	8.955	10	October-weekend
26	7.059	12	December-weekday
27	5.746	12	December-weekend
28	3.508	3	March-weekend
29	3.312	1	January-weekend
30	0.986	4	April-weekend

7.4 Additional Constraints

RESOLVE layers investment decisions on top of the operational model described above. Each new investment identified in RESOLVE has an impact on how the system operates; the portfolio of investments, as a whole, must satisfy a number of additional conditions.

+ Planning reserve margin (PRM): When making investment decisions, RESOLVE requires the portfolio to include enough firm capacity to meet the annual system peak load plus an additional specified amount of PRM requirement. The contribution of each resource type towards this requirement depends on its attributes and varies by type: for instance, variable renewables are discounted more compared to thermal generations because the uncertainties of generation during peak hours. In this study, a PRM requirement of 9% is used for PJM.

+ Renewables Portfolio Standard (RPS) requirements: RPS requirements have become the most common policy mechanism in the United States to encourage renewable development. RESOLVE enforces an RPS requirement as a percentage of retail sales to ensure that the total quantity of energy procured from renewable resources meets the RPS target in each year. RESOLVE has the ability to flag which resources can contribute to an RPS requirement, which enables policies like a CES, where nuclear resources are eligible to contribute to the target, to be modeled.

- **Greenhouse gas cap:** RESOLVE also allows users to specify and enforce a greenhouse gas constraint on the resource portfolio for a region. As the name suggests, the emission cap type policy requires that annual emissions generated in the entire system be less than or equal to the designed maximum emissions cap. This type of policy is usually implemented by having limited amount of emission allowances within the system. As a result, thermal generators need to purchase allowances for the carbon they produced from the market or from carbon-free generators. In its most extreme form, a greenhouse cap at zero emissions, as illustrated in E3's 100% GHG case in 2050, would preclude all power-sector emissions, though some "zero-emission" fuels such as biofuels or hydrogen still qualify.

- **Resource limitations:** Many potential new resources are limited in their potential for new development. This is particularly true for renewable resources such as wind and solar. RESOLVE enforces limits on the maximum potential of each new resource that can be included in the portfolio, imposing practical limitations on the amount of any one type of resource that may be developed. The same limitation can be applied to the retirement of existing resources. RESOLVE considers each of these constraints simultaneously, selecting the combination of new generation resources and old resource retirements that adheres to these constraints while minimizing the sum of investment and operational costs.

7.5 Key Model Outputs

RESOLVE produces a large amount of results from technology level unit commitment decisions to total carbon emission in the system. This extensive information gives users a complete view of the future system and makes RESOLVE versatile for different analysis. The following list of outputs is produced by RESOLVE and are the subject of discussion and interpretation in this study:

- **Total system cost ($/yr):** RESOLVE reports the total annual system costs in the study footprint to provide service to its customers. This study focuses on the relative differences in system costs among scenarios, generally measuring changes in the relative to the Reference case. The cost impacts for each scenario comprise changes in fixed costs (capital and fixed O&M costs for new generation resources, new energy storage devices, and the required transmission resources with the new generation) and operating costs (variable O&M costs and fuel costs).

- **Greenhouse gas emissions (MMTCO2):** This result summarizes the total annual carbon emission in the system. By comparing the carbon emissions and total resource costs between different scenarios, we can conclude the relative effectiveness of the strategic measure in enabling carbon reductions.

- **Resource additions and retirements for each period (MW):** The cumulative additions and retirements by resource type show the optimal strategy to meet future load given any emissions constraints. Some existing resources may be uneconomic and retire to make room for new cheaper or zero-carbon investments.

- **Annual generation by resource type (GWh):** Energy balance shows the annual system load and energy produced by each resource type in each modeled year. It provides insights from a different angle than capacity investments. It can help answer questions like: Which types of resources are dispatched more? How do the dispatch behaviors change over the years?

- **Renewable curtailment (GWh):** RESOLVE estimates the amount of renewable curtailment that would be expected in each year of the analysis as a result of "oversupply"—when the total amount of must-run and renewable generation exceeds regional load plus export capability—based on its hourly simulation of operations. As the primary renewable integration challenge at high renewable penetrations, this measure is a useful proxy for renewable integration costs.

+ Wholesale market prices ($/MWh): Outputs from RESOLVE can be used to estimate wholesale market prices on an hourly basis. As an optimization model, RESOLVE produces “shadow prices” in each hour that represent the marginal cost of generation given all the resources available at the time; these marginal costs serve as a proxy for wholesale market prices.

+ Average greenhouse gas abatement cost ($/metric ton): RESOLVE results can also be used to estimate average and marginal costs of greenhouse gas abatement by comparing the amount of greenhouse gas abatement achieved (relative to a Reference Case) and the incremental cost (relative to that same case). For this study, most results focus on the snapshots of the system in 2030 and 2050. However, in some cases, intermediate results are also presented when relevant to the study’s objectives and key messages.

7.6 Detailed RESOLVE Annual Generation, Installed Capacity, and Cumulative Capacity Additions & Retirements Results

Scenario	Resource Type	Annual Energy (TWh)							Installed Capacity (GW)							Cumulative Capacity Additions (GW)							Cumulative Capacity Retirements (GW)						
		2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
Reference	Nuclear	276.2	165.6	124.4	124.4	124.4	124.4	124.4	33.0	19.8	14.9	14.9	14.9	14.9	14.9	-	-	-	-	-	-	-	-	(13.3)	(18.2)	(18.2)	(18.2)	(18.2)	(18.2)
	Coal	176.3	141.7	107.7	117.4	130.2	131.9	139.3	51.3	32.0	22.3	22.3	22.3	22.3	22.3	-	-	-	-	-	-	-	-	(19.3)	(29.0)	(29.0)	(29.0)	(29.0)	(29.0)
	Combined Cycle	236.4	415.5	514.5	519.4	518.2	529.1	525.4	51.7	65.3	85.0	85.7	85.7	85.7	86.0	-	3.6	4.7	5.5	5.5	5.5	5.8	-	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)
	Combustion Turbine	4.9	8.9	7.4	9.7	12.3	13.4	12.9	29.1	29.1	29.1	29.1	29.1	29.1	29.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Steam Turbine	7.0	2.3	1.8	1.8	1.8	1.9	2.0	7.9	1.6	1.6	1.6	1.6	1.6	1.6	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(6.3)	(6.3)	(6.3)
	Fuel Oil	-	-	-	-	-	0.0	0.0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	-	-	-	-	-	-	-	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	10.9	11.1	11.0	11.0	10.9	10.6	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	26.9	32.3	40.0	55.1	67.1	84.2	11.3	17.2	20.8	25.8	34.0	40.2	49.0	-	-	-	0.2	6.5	12.7	21.5	-	-	-	-	-	-	-
	Wind	33.0	33.4	33.4	33.4	33.4	34.6	71.3	9.5	9.7	9.7	9.7	9.7	10.0	19.8	-	-	-	-	-	0.3	10.1	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Battery Storage	0.1	0.1	0.0	0.1	0.1	0.1	0.2	0.3	0.3	0.3	0.3	0.3	0.3	1.5	-	-	-	-	-	-	1.2	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(0.5)	(0.7)	(0.9)	(1.1)	(1.2)	(1.1)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	0.1	0.4	0.5	0.6	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BAU	Nuclear	276.1	199.1	191.4	191.4	191.4	191.4	191.4	33.0	23.8	22.9	22.9	22.9	22.9	22.9	-	-	-	-	-	-	-	-	(9.3)	(10.2)	(10.2)	(10.2)	(10.2)	(10.2)
	Coal	184.0	148.8	139.5	150.0	164.5	171.3	167.8	51.3	29.4	24.4	24.4	24.4	24.4	24.4	-	-	-	-	-	-	-	-	(21.9)	(26.9)	(26.9)	(26.9)	(26.9)	(26.9)
	Combined Cycle	230.0	346.1	318.0	294.4	273.7	259.3	270.9	51.7	61.5	62.6	62.9	64.0	64.2	67.1	-	-	-	0.3	1.3	8.0	16.9	-	(3.2)	(20.5)	(20.5)	(20.5)	(27.1)	(33.0)
	Combustion Turbine	5.4	13.9	12.8	15.8	17.8	19.4	16.2	29.1	29.1	29.1	29.1	29.1	29.1	29.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Steam Turbine	5.3	2.7	3.3	3.7	3.8	3.6	3.0	7.9	2.8	2.8	2.6	2.6	2.6	1.5	-	-	-	-	-	-	-	-	(5.1)	(5.1)	(5.3)	(5.3)	(5.3)	(6.4)
	Fuel Oil	-	-	-	-	-	-	-	0.4	0.4	0.1	-	-	-	-	-	-	-	-	-	-	-	(6.7)	(6.7)	(7.0)	(7.1)	(7.1)	(7.1)	(7.1)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.0	11.6	11.6	11.3	11.3	11.0	10.9	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	30.5	55.8	67.1	77.8	89.1	106.2	11.3	18.8	32.4	39.4	45.3	51.1	59.8	-	1.7	11.6	13.7	17.8	23.6	32.3	-	-	-	-	-	-	-
	Wind	33.0	42.0	74.3	74.3	96.9	119.6	156.1	9.5	11.7	20.6	20.6	27.3	34.0	44.9	-	2.0	10.9	10.9	17.7	24.3	35.2	-	-	-	-	-	-	-
	Wind Offshore	-	11.5	26.3	49.8	49.8	49.8	49.8	-	3.2	7.3	13.9	13.9	13.9	13.9	-	3.2	7.3	13.9	13.9	13.9	13.9	-	-	-	-	-	-	-
	Battery Storage	0.1	(0.2)	(0.1)	(0.1)	(0.1)	(0.4)	(0.7)	0.3	0.3	0.3	0.3	0.3	0.6	1.9	-	-	-	-	-	0.3	1.6	-	-	-	-	-	-	-
	Pumped Hydro	(1.4)	(1.1)	(1.1)	(1.3)	(1.6)	(1.8)	(2.3)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.0	0.1	0.2	0.3	0.4	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BAU No Carbon Price	Nuclear	276.2	165.6	110.9	110.9	110.9	110.9	110.8	33.0	19.8	13.2	13.2	13.2	13.2	13.2	-	-	-	-	-	-	-	-	(13.3)	(19.8)	(19.8)	(19.8)	(19.8)	(19.8)
	Coal	178.9	144.8	64.8	68.9	75.9	76.4	80.4	51.3	32.4	13.9	13.6	13.6	13.6	13.6	-	-	-	-	-	-	-	-	(18.9)	(37.4)	(37.7)	(37.7)	(37.7)	(37.7)
	Combined Cycle	234.4	388.5	477.2	460.7	449.0	442.4	443.3	51.7	62.9	81.4	81.4	81.4	81.4	81.5	-	1.1	1.1	1.1	1.1	1.1	1.2	-	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)
	Combustion Turbine	4.6	8.8	9.6	12.2	13.0	13.1	12.2	29.1	29.1	29.1	29.1	29.1	29.1	29.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Steam Turbine	6.6	2.3	2.2	2.2	2.0	1.9	1.8	7.9	1.6	1.6	1.6	1.6	1.6	1.6	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(6.3)	(6.3)	(6.3)
	Fuel Oil	-	-	-	-	-	0.0	0.0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	-	-	-	-	-	-	-	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.7	11.8	11.7	11.7	11.6	11.1	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	33.1	57.7	69.1	85.5	98.8	109.8	11.3	20.1	33.6	40.7	49.5	56.3	62.0	-	2.9	12.8	15.1	22.0	28.8	34.5	-	-	-	-	-	-	-
	Wind	33.0	39.1	72.0	72.0	88.4	108.7	151.9	9.5	11.1	19.9	19.9	24.7	30.6	43.6	-	1.4	10.2	10.2	15.0	20.9	33.9	-	-	-	-	-	-	-
	Wind Offshore	-	11.5	26.3	49.8	49.8	49.8	49.8	-	3.2	7.3	13.9	13.9	13.9	13.9	-	3.2	7.3	13.9	13.9	13.9	13.9	-	-	-	-	-	-	-
	Battery Storage	0.1	(0.1)	(0.0)	(0.0)	(0.1)	(0.2)	(0.7)	0.3	0.3	0.3	0.3	0.3	0.6	4.2	-	-	-	-	-	0.3	3.9	-	-	-	-	-	-	-
	Pumped Hydro	(1.4)	(0.4)	(0.5)	(1.1)	(1.0)	(1.0)	(1.1)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.0	0.1	0.3	0.4	0.4	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Scenario	Resource Type	Annual Energy (TWh)							Installed Capacity (GW)							Cumulative Capacity Additions (GW)							Cumulative Capacity Retirements (GW)						
		2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
BAU System Carbon Price	Nuclear	276.3	256.5	248.8	248.8	248.8	248.8	247.6	33.0	30.6	29.7	29.7	29.7	29.7	29.7	-	-	-	-	-	-	-	-	(2.4)	(3.3)	(3.3)	(3.3)	(3.3)	(3.3)
	Coal	174.2	122.2	-	-	-	-	-	51.3	30.8	-	-	-	-	-	-	-	-	-	-	-	-	-	(20.5)	(51.3)	(51.3)	(51.3)	(51.3)	(51.3)
	Combined Cycle	237.1	321.8	402.7	393.1	389.4	363.3	320.8	51.7	62.0	80.5	80.5	80.5	80.5	80.2	-	-	-	-	-	-	-	-	(2.7)	(2.7)	(2.7)	(2.7)	(2.7)	(3.0)
	Combustion Turbine	6.0	7.8	11.6	11.6	11.6	10.8	9.6	29.1	28.6	28.6	28.6	28.6	28.6	28.6	-	-	-	-	-	-	-	-	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)
	Steam Turbine	7.3	2.1	1.8	1.7	1.6	1.5	0.5	7.9	1.6	1.6	1.6	1.6	1.6	0.6	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(6.3)	(6.3)	(7.3)
	Fuel Oil	-	-	-	-	-	-	-	0.4	0.4	0.3	0.0	0.0	0.0	-	-	-	-	-	-	-	-	(6.7)	(6.7)	(6.8)	(7.1)	(7.1)	(7.1)	(7.1)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.6	11.8	11.0	11.0	10.7	10.6	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	30.5	57.0	69.1	87.0	96.9	156.4	11.3	18.8	32.9	40.4	49.8	54.8	84.9	-	1.7	12.1	14.7	22.3	27.3	57.4	-	-	-	-	-	-	-
	Wind	33.0	41.8	72.9	72.9	87.9	132.2	176.7	9.5	11.6	20.2	20.2	24.6	37.8	50.9	-	1.9	10.5	10.5	15.0	28.1	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	11.5	26.3	49.8	49.8	49.8	49.8	-	3.2	7.3	13.9	13.9	13.9	13.9	-	3.2	7.3	13.9	13.9	13.9	13.9	-	-	-	-	-	-	-
	Battery Storage	0.1	(0.1)	(0.0)	0.0	(0.1)	(0.1)	(0.8)	0.3	0.3	0.3	0.3	0.3	0.9	3.8	-	-	-	-	-	0.6	3.5	-	-	-	-	-	-	-
	Pumped Hydro	(1.6)	(0.9)	(1.0)	(1.7)	(1.7)	(1.6)	(1.8)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.1	0.1	0.3	0.3	0.3	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
BAU Tech Neutral	Nuclear	276.2	165.6	107.1	71.7	71.7	71.7	71.7	33.0	19.8	12.8	8.6	8.6	8.6	8.6	-	-	-	-	-	-	-	-	(13.3)	(20.2)	(24.5)	(24.5)	(24.5)	(24.5)
	Coal	176.3	141.4	80.9	87.4	97.1	97.8	104.0	51.3	32.4	17.3	17.3	17.3	17.3	17.3	-	-	-	-	-	-	-	-	(18.9)	(33.9)	(33.9)	(33.9)	(33.9)	(33.9)
	Combined Cycle	236.4	392.1	466.2	482.0	467.3	460.7	459.8	51.7	63.2	81.7	82.0	82.8	82.9	82.9	-	1.5	1.5	1.8	2.5	2.7	2.7	-	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)	(3.0)
	Combustion Turbine	4.9	8.5	8.3	11.0	12.6	12.4	11.3	29.1	29.1	29.1	29.1	29.1	29.1	29.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Steam Turbine	7.0	2.3	2.1	2.0	1.8	1.7	1.6	7.9	1.6	1.6	1.6	1.6	1.6	1.6	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(6.3)	(6.3)	(6.3)
	Fuel Oil	-	-	-	-	0.0	0.0	0.0	2.4	2.4	2.4	2.4	2.4	2.4	2.4	-	-	-	-	-	-	-	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.8	11.8	11.8	11.7	11.6	11.6	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	33.1	53.1	81.9	96.1	105.9	134.5	11.3	20.1	31.0	46.9	54.6	59.7	74.6	-	2.9	10.2	21.3	27.1	32.2	47.1	-	-	-	-	-	-	-
	Wind	33.0	50.6	103.0	108.8	127.7	151.5	176.7	9.5	13.8	28.8	30.6	36.2	43.4	50.9	-	4.1	19.2	21.0	26.6	33.7	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Battery Storage	0.1	(0.1)	(0.1)	(0.1)	(0.1)	(0.3)	(1.2)	0.3	0.3	0.3	0.3	0.3	1.4	5.4	-	-	-	-	-	1.1	5.0	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(0.4)	(0.5)	(0.6)	(0.8)	(0.8)	(0.6)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.1	0.4	0.5	0.5	0.3	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60% GHG	Nuclear	276.2	247.1	239.5	239.5	239.5	239.5	239.1	33.0	29.5	28.6	28.6	28.6	28.6	28.6	-	-	-	-	-	-	-	-	(3.5)	(4.4)	(4.4)	(4.4)	(4.4)	(4.4)
	Coal	176.3	132.3	16.0	12.7	0.0	-	-	51.3	30.8	3.4	2.6	0.0	-	-	-	-	-	-	-	-	-	-	(20.5)	(47.9)	(48.6)	(51.3)	(51.3)	(51.3)
	Combined Cycle	236.4	343.8	482.1	490.4	477.4	426.9	412.9	51.7	64.7	83.8	83.8	83.8	83.8	83.8	-	-	0.6	0.6	0.6	0.6	0.6	-	-	-	-	-	-	-
	Combustion Turbine	4.9	6.3	11.2	12.5	11.9	11.1	10.6	29.1	29.1	29.1	29.1	29.1	29.1	29.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Steam Turbine	7.0	4.8	5.8	5.3	3.1	1.2	1.5	7.9	4.7	4.7	4.7	4.1	2.1	2.1	-	-	-	-	-	-	-	-	(3.2)	(3.2)	(3.2)	(3.8)	(5.8)	(5.8)
	Fuel Oil	-	-	-	-	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	-	-	-	-	-	-	-	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.0	11.4	11.2	10.8	10.7	10.6	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	26.9	33.2	52.1	72.1	86.3	119.2	11.3	17.2	21.2	32.0	42.6	49.9	66.8	-	-	0.5	6.3	15.1	22.4	39.3	-	-	-	-	-	-	-
	Wind	33.0	33.4	33.4	33.4	71.7	137.7	176.7	9.5	9.7	9.7	9.7	19.8	39.3	50.9	-	-	-	-	10.1	29.6	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Battery Storage	0.1	0.0	0.1	0.1	(0.0)	(0.1)	(0.0)	0.3	0.3	0.3	0.3	0.3	0.5	2.9	-	-	-	-	-	0.2	2.6	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(0.8)	(0.8)	(1.1)	(1.4)	(1.2)	(1.1)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.1	0.3	0.5	0.5	0.3	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

		Annual Energy (TWh)							Installed Capacity (GW)							Cumulative Capacity Additions (GW)							Cumulative Capacity Retirements (GW)						
Scenario	**Resource Type**	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
80% GHG	Nuclear	276.2	266.1	266.1	266.0	265.4	261.2	256.8	33.0	31.8	31.8	31.8	31.8	31.8	31.8	-	-	-	-	-	-	-	-	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
	Coal	176.3	127.2	7.3	-	-	-	-	51.3	30.8	1.6	-	-	-	-	-	-	-	-	-	-	-	-	(20.5)	(49.7)	(51.3)	(51.3)	(51.3)	(51.3)
	Combined Cycle	236.4	331.8	453.9	404.9	325.7	253.8	216.8	51.7	62.8	81.3	78.3	75.0	73.2	59.8	-	-	-	-	-	-	-	-	(1.9)	(1.9)	(4.9)	(8.2)	(10.0)	(23.3)
	Combustion Turbine	4.9	7.2	12.5	9.8	9.0	5.2	2.9	29.1	29.1	29.1	29.1	29.1	29.1	28.4	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.7)
	Steam Turbine	7.0	2.1	2.1	0.4	0.3	-	-	7.9	1.6	1.6	1.6	1.6	-	-	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(6.3)	(7.9)	(7.9)
	Fuel Oil	-	-	-	0.0	0.0	-	-	1.7	1.7	1.7	1.6	0.6	-	-	-	-	-	-	-	-	-	(5.4)	(5.4)	(5.4)	(5.5)	(6.5)	(7.1)	(7.1)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.0	11.3	10.7	10.5	10.4	10.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	26.9	46.0	72.5	106.7	207.9	260.0	11.3	17.2	27.7	41.8	59.6	111.1	140.2	-	-	7.0	16.2	32.1	83.6	112.7	-	-	-	-	-	-	-
	Wind	33.0	33.4	33.4	92.8	169.2	176.3	175.4	9.5	9.7	9.7	25.9	48.8	50.9	50.9	-	-	-	16.3	39.1	41.3	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	-	55.1	-	-	-	-	-	-	15.5	-	-	-	-	-	-	15.5	-	-	-	-	-	-	-
	Battery Storage	0.1	0.1	0.1	(0.0)	(0.0)	(2.5)	(6.6)	0.3	0.3	0.3	0.3	0.3	6.9	22.0	-	-	-	-	-	6.6	21.7	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(1.0)	(0.9)	(1.3)	(1.6)	(2.0)	(2.8)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.2	0.5	0.4	2.2	1.8	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	-	1.9	6.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90% GHG	Nuclear	276.2	266.1	266.1	265.8	261.9	253.5	245.9	33.0	31.8	31.8	31.8	31.8	31.8	31.8	-	-	-	-	-	-	-	-	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
	Coal	176.3	109.0	-	-	-	-	-	51.3	30.8	-	-	-	-	-	-	-	-	-	-	-	-	-	(20.5)	(51.3)	(51.3)	(51.3)	(51.3)	(51.3)
	Combined Cycle	236.4	347.2	430.0	339.5	251.9	164.9	110.5	51.7	60.4	78.9	74.9	73.1	50.1	44.4	-	-	-	-	-	-	-	-	(4.3)	(4.3)	(8.3)	(10.1)	(33.1)	(38.8)
	Combustion Turbine	4.9	11.0	9.8	8.7	6.1	0.8	0.1	29.1	28.6	28.6	28.6	28.6	28.6	28.5	-	-	-	-	-	-	-	-	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.7)
	Steam Turbine	7.0	1.3	0.7	0.3	0.2	-	-	7.9	1.6	1.6	1.6	1.1	-	-	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(6.8)	(7.9)	(7.9)
	Fuel Oil	-	-	-	-	-	-	-	1.7	1.7	1.7	0.8	-	-	-	-	-	-	-	-	-	-	(5.4)	(5.4)	(5.4)	(6.3)	(7.1)	(7.1)	(7.1)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.1	10.9	10.6	10.6	10.4	10.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	26.9	58.0	87.1	180.5	274.6	287.9	11.3	17.2	33.8	49.1	96.7	149.8	160.1	-	-	13.1	23.5	69.3	122.3	132.6	-	-	-	-	-	-	-
	Wind	33.0	33.4	57.3	145.4	176.3	174.8	171.2	9.5	9.7	15.7	41.8	50.9	50.9	50.9	-	-	6.0	32.1	41.3	41.3	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	33.7	148.0	-	-	-	-	-	9.7	44.2	-	-	-	-	-	9.7	44.2	-	-	-	-	-	-	-
	Battery Storage	0.1	0.1	0.0	(0.0)	(1.4)	(7.8)	(10.5)	0.3	0.3	0.3	0.3	2.4	27.0	36.2	-	-	-	-	2.1	26.7	35.9	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(1.2)	(1.0)	(1.3)	(2.1)	(3.2)	(4.2)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.2	0.4	1.7	10.9	10.5	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	1.0	12.3	32.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
100% GHG	Nuclear	276.2	266.0	266.1	264.8	253.6	244.6	229.2	33.0	31.8	31.8	31.8	31.8	31.8	31.8	-	-	-	-	-	-	-	-	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
	Coal	176.3	107.4	-	-	-	-	-	51.3	30.8	-	-	-	-	-	-	-	-	-	-	-	-	-	(20.5)	(51.3)	(51.3)	(51.3)	(51.3)	(51.3)
	Combined Cycle	236.4	328.5	380.2	275.7	178.4	69.3	28.7	51.7	57.0	75.5	72.8	54.2	33.4	27.6	-	-	-	-	-	-	-	-	(7.7)	(7.7)	(10.3)	(29.0)	(49.8)	(55.6)
	Combustion Turbine	4.9	11.1	9.0	7.2	1.0	-	-	29.1	27.9	27.9	27.9	27.9	27.4	26.8	-	-	-	-	-	-	-	-	(1.2)	(1.2)	(1.2)	(1.2)	(1.7)	(2.4)
	Steam Turbine	7.0	0.7	0.4	0.2	-	-	-	7.9	1.6	1.6	1.3	-	-	-	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.6)	(7.9)	(7.9)	(7.9)
	Fuel Oil	-	-	-	-	-	-	-	0.8	0.8	0.8	-	-	-	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(7.1)	(7.1)	(7.1)	(7.1)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	10.7	10.7	10.3	10.3	10.4	10.5	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	30.5	77.0	127.7	265.3	319.1	353.6	11.3	18.8	43.0	69.4	144.6	176.4	200.1	-	1.7	22.2	43.8	117.1	148.9	172.6	-	-	-	-	-	-	-
	Wind	33.0	51.1	89.5	172.1	175.2	169.3	165.7	9.5	13.9	25.0	49.6	50.9	50.9	50.9	-	4.2	15.3	39.9	41.3	41.3	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	106.5	194.9	-	-	-	-	-	31.4	61.8	-	-	-	-	-	31.4	61.8	-	-	-	-	-	-	-
	Battery Storage	0.1	(0.0)	0.0	(0.1)	(6.5)	(14.4)	(20.1)	0.3	0.3	0.3	0.3	22.4	54.7	66.3	-	-	-	-	22.1	54.4	66.0	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(1.3)	(1.1)	(1.9)	(3.3)	(4.0)	(4.9)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.3	0.4	11.7	11.9	12.2	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	0.0	10.4	31.3	63.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Scenario	Resource Type	Annual Energy (TWh)							Installed Capacity (GW)							Cumulative Capacity Additions (GW)							Cumulative Capacity Retirements (GW)						
		2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
Low CES	Nuclear	276.2	246.8	239.1	239.1	239.1	239.0	238.8	33.0	29.5	28.6	28.6	28.6	28.6	28.6	-	-	-	-	-	-	-	-	(3.6)	(4.5)	(4.5)	(4.5)	(4.5)	(4.5)
	Coal	176.3	132.3	16.2	8.7	-	-	-	51.3	30.8	3.4	1.8	-	-	-	-	-	-	-	-	-	-	-	(20.5)	(47.9)	(49.4)	(51.3)	(51.3)	(51.3)
	Combined Cycle	236.4	344.1	482.2	494.6	476.4	420.1	423.2	51.7	64.7	83.8	83.8	83.8	83.8	83.8	-	-	0.6	0.6	0.6	0.6	0.6	-	-	-	-	-	-	-
	Combustion Turbine	4.9	6.3	11.2	12.6	10.5	9.3	9.7	29.1	29.1	29.1	29.1	29.1	29.1	29.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Steam Turbine	7.0	4.8	5.8	5.4	3.2	1.7	2.0	7.9	4.7	4.7	4.7	3.8	2.3	2.3	-	-	-	-	-	-	-	-	(3.2)	(3.2)	(3.2)	(4.1)	(5.6)	(5.6)
	Fuel Oil	-	-	-	-	0.0	0.0	0.0	1.7	1.7	1.7	1.7	1.7	1.7	1.7	-	-	-	-	-	-	-	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	(5.4)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.1	11.4	11.4	10.6	10.7	11.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	26.9	33.3	54.4	72.2	83.2	115.2	11.3	17.2	21.3	33.2	42.7	48.2	64.8	-	-	0.5	7.5	15.2	20.7	37.3	-	-	-	-	-	-	-
	Wind	33.0	33.4	33.4	33.4	79.8	155.6	176.7	9.5	9.7	9.7	9.7	22.1	44.8	50.9	-	-	-	-	12.5	35.1	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Battery Storage	0.1	0.0	0.1	(0.4)	(0.8)	(0.8)	(4.8)	0.3	0.3	0.3	0.3	0.3	0.3	3.0	-	-	-	-	0.0	0.0	2.7	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(0.9)	(0.8)	(3.2)	(5.9)	(6.6)	(2.8)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.1	0.3	0.5	0.5	0.4	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid CES	Nuclear	276.2	266.1	266.1	266.0	265.7	262.0	257.1	33.0	31.8	31.8	31.8	31.8	31.8	31.8	-	-	-	-	-	-	-	-	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
	Coal	176.3	132.5	6.3	-	-	-	-	51.3	30.8	1.4	-	-	-	-	-	-	-	-	-	-	-	-	(20.5)	(49.9)	(51.3)	(51.3)	(51.3)	(51.3)
	Combined Cycle	236.4	326.6	456.8	421.4	349.4	272.5	219.3	51.7	62.9	81.4	79.2	76.2	75.0	60.7	-	-	-	-	-	-	-	-	(1.8)	(1.8)	(4.0)	(7.0)	(8.2)	(22.5)
	Combustion Turbine	4.9	7.1	12.3	8.3	8.5	5.9	3.5	29.1	29.1	29.1	29.0	29.0	29.0	28.8	-	-	-	-	-	-	-	-	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.4)
	Steam Turbine	7.0	2.0	2.1	0.9	0.6	0.2	-	7.9	1.6	1.6	1.6	1.6	1.1	-	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(6.3)	(6.8)	(7.9)
	Fuel Oil	-	-	-	-	0.0	-	-	1.7	1.7	1.7	1.6	0.6	-	-	-	-	-	-	-	-	-	(5.4)	(5.4)	(5.4)	(5.5)	(6.5)	(7.1)	(7.1)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.1	11.4	10.7	10.7	10.8	10.9	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	26.9	46.6	67.8	101.2	193.1	256.1	11.3	17.2	28.0	40.0	56.9	103.4	137.5	-	-	7.3	14.4	29.4	76.0	110.0	-	-	-	-	-	-	-
	Wind	33.0	33.4	33.4	87.9	156.5	176.3	175.9	9.5	9.7	9.7	24.6	45.1	50.9	50.9	-	-	-	14.9	35.4	41.3	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	-	60.1	-	-	-	-	-	-	17.4	-	-	-	-	-	-	17.4	-	-	-	-	-	-	-
	Battery Storage	0.1	0.1	(0.3)	(0.8)	(0.8)	(5.1)	(9.6)	0.3	0.3	0.3	0.3	0.3	4.2	20.6	-	-	-	-	0.0	3.9	20.3	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(1.0)	(2.8)	(6.3)	(6.6)	(3.2)	(3.7)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.2	0.4	0.4	0.2	0.1	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	-	1.0	6.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
High CES	Nuclear	276.2	266.1	266.1	265.0	256.1	246.3	217.6	33.0	31.8	31.8	31.8	31.8	31.8	31.8	-	-	-	-	-	-	-	-	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
	Coal	176.3	134.5	-	-	-	-	-	51.3	30.8	-	-	-	-	-	-	-	-	-	-	-	-	-	(20.5)	(51.3)	(51.3)	(51.3)	(51.3)	(51.3)
	Combined Cycle	236.4	323.0	380.1	298.1	210.2	110.2	28.2	51.7	55.4	73.9	72.0	61.0	38.5	29.1	-	-	-	-	-	-	-	-	(9.3)	(9.3)	(11.1)	(22.2)	(44.7)	(54.1)
	Combustion Turbine	4.9	8.6	7.9	6.5	2.6	0.4	-	29.1	29.1	29.1	29.1	28.5	27.0	19.3	-	-	-	-	-	-	-	-	-	-	-	(0.6)	(2.2)	(9.8)
	Steam Turbine	7.0	2.2	0.9	0.3	-	-	-	7.9	1.6	1.6	1.3	-	-	-	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.6)	(7.9)	(7.9)	(7.9)
	Fuel Oil	-	-	-	-	-	-	-	1.7	1.7	0.9	-	-	-	-	-	-	-	-	-	-	-	(5.4)	(5.4)	(6.2)	(7.1)	(7.1)	(7.1)	(7.1)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.0	10.7	10.7	10.9	11.2	11.8	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	26.9	77.1	111.5	242.0	310.8	394.3	11.3	17.2	43.1	61.6	130.4	171.5	229.1	-	-	22.3	35.9	102.9	144.0	201.6	-	-	-	-	-	-	-
	Wind	33.0	33.4	95.9	171.3	175.1	171.2	162.1	9.5	9.7	26.9	49.4	50.9	50.9	50.9	-	-	17.2	39.7	41.3	41.3	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	83.3	188.3	-	-	-	-	-	24.0	60.2	-	-	-	-	-	24.0	60.2	-	-	-	-	-	-	-
	Battery Storage	0.1	0.0	(0.8)	(0.7)	(7.9)	(16.5)	(27.4)	0.3	0.3	0.3	0.3	14.9	48.1	67.1	-	-	-	-	14.6	47.8	66.8	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(1.0)	(6.2)	(6.4)	(3.5)	(4.0)	(5.2)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.3	0.2	0.1	-	-	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	0.0	7.1	25.3	82.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Scenario	Resource Type	Annual Energy (TWh)							Installed Capacity (GW)							Cumulative Capacity Additions (GW)							Cumulative Capacity Retirements (GW)						
		2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
60% RPS	Nuclear	276.2	165.5	106.3	85.1	72.0	8.3	-	33.0	19.8	12.7	10.2	8.7	1.0	-	-	-	-	-	-	-	-	-	(13.3)	(20.3)	(22.9)	(24.3)	(32.0)	(33.0)
	Coal	176.3	135.8	14.4	15.4	17.1	18.2	6.3	51.3	31.9	3.5	3.5	3.5	3.5	1.1	-	-	-	-	-	-	-	-	(19.3)	(47.8)	(47.8)	(47.8)	(47.8)	(50.2)
	Combined Cycle	236.4	349.7	445.2	415.5	379.5	390.3	369.3	51.7	64.9	83.8	83.8	83.8	83.8	80.9	-	0.2	0.7	0.7	0.7	0.7	0.7	-	-	-	-	-	-	(3.0)
	Combustion Turbine	4.9	6.6	12.2	13.6	13.3	11.9	9.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Steam Turbine	7.0	3.5	3.6	3.4	2.9	3.0	1.8	7.9	2.7	2.7	2.7	2.7	2.7	1.6	-	-	-	-	-	-	-	-	(5.2)	(5.2)	(5.2)	(5.2)	(5.2)	(6.3)
	Fuel Oil	-	-	-	0.0	0.0	0.0	-	2.4	2.4	2.4	2.4	2.4	2.4	0.5	-	-	-	-	-	-	-	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(6.5)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.8	11.8	11.8	11.8	11.9	11.9	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	40.2	84.3	135.4	214.8	299.6	334.0	11.3	23.6	46.4	73.7	114.0	160.6	180.5	-	6.5	25.6	48.0	86.5	133.1	153.0	-	-	-	-	-	-	-
	Wind	33.0	92.3	154.3	176.6	176.2	175.0	174.2	9.5	25.9	44.3	50.9	50.9	50.9	50.9	-	16.2	34.6	41.3	41.3	41.3	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	-	72.2	-	-	-	-	-	-	20.4	-	-	-	-	-	-	20.4	-	-	-	-	-	-	-
	Battery Storage	0.1	(0.2)	(0.0)	(0.0)	(0.8)	(3.6)	(6.5)	0.3	0.3	0.3	0.5	3.7	13.0	23.4	-	-	-	0.2	3.4	12.7	23.0	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(0.6)	(0.4)	(0.6)	(1.5)	(2.2)	(2.4)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.2	0.2	0.2	0.3	0.1	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	0.0	0.1	0.9	7.4	14.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80% RPS	Nuclear	276.2	165.5	98.8	34.2	-	-	-	33.0	19.8	11.9	4.2	-	-	-	-	-	-	-	-	-	-	-	(13.3)	(21.1)	(28.9)	(33.0)	(33.0)	(33.0)
	Coal	176.3	133.9	6.8	7.8	-	-	-	51.3	31.8	1.8	1.8	-	-	-	-	-	-	-	-	-	-	-	(19.5)	(49.4)	(49.4)	(51.3)	(51.3)	(51.3)
	Combined Cycle	236.4	312.6	376.8	370.6	341.0	265.3	194.4	51.7	62.6	81.1	81.1	76.0	65.7	59.8	-	-	-	-	-	-	-	-	(2.0)	(2.0)	(2.0)	(7.2)	(17.5)	(23.4)
	Combustion Turbine	4.9	6.6	13.5	11.6	10.8	7.7	4.9	29.1	29.1	29.1	29.1	29.1	29.1	28.9	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.2)
	Steam Turbine	7.0	1.9	2.1	2.0	1.9	0.4	-	7.9	1.6	1.6	1.6	1.6	0.4	-	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(6.3)	(7.5)	(7.9)
	Fuel Oil	-	-	-	0.0	-	-	-	2.4	2.4	2.4	2.4	2.4	-	-	-	-	-	-	-	-	-	(4.7)	(4.7)	(4.7)	(4.7)	(4.7)	(7.1)	(7.1)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.8	11.8	11.8	11.8	11.9	11.7	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	41.5	146.2	246.3	348.0	357.9	365.0	11.3	24.2	77.8	130.1	193.3	200.1	206.3	-	7.1	57.1	104.4	165.8	172.6	178.8	-	-	-	-	-	-	-
	Wind	33.0	131.9	176.6	176.0	172.4	170.5	163.0	9.5	37.5	50.9	50.9	50.9	50.9	50.9	-	27.8	41.3	41.3	41.3	41.3	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	9.3	112.1	248.4	-	-	-	-	2.6	32.3	74.8	-	-	-	-	2.6	32.3	74.8	-	-	-	-	-	-	-
	Battery Storage	0.1	(0.2)	(0.0)	(2.4)	(6.3)	(9.3)	(13.3)	0.3	0.3	0.9	9.6	21.3	32.9	46.0	-	-	0.6	9.3	21.0	32.6	45.7	-	-	-	-	-	-	-
	Pumped Hydro	(1.4)	(0.7)	(0.8)	(1.7)	(3.5)	(3.7)	(4.3)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.1	0.2	0.2	-	-	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	0.1	2.5	26.0	35.1	64.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
100% RPS	Nuclear	276.2	165.0	51.8	-	-	-	-	33.0	19.8	6.4	-	-	-	-	-	-	-	-	-	-	-	-	(13.3)	(26.6)	(33.0)	(33.0)	(33.0)	(33.0)
	Coal	176.3	130.4	6.0	-	-	-	-	51.3	31.6	1.6	-	-	-	-	-	-	-	-	-	-	-	-	(19.7)	(49.7)	(51.3)	(51.3)	(51.3)	(51.3)
	Combined Cycle	236.4	270.3	342.3	306.6	214.2	105.8	11.8	51.7	61.4	79.9	65.4	56.9	42.7	23.7	-	-	-	-	-	-	-	-	(3.3)	(3.3)	(17.8)	(26.3)	(40.5)	(59.5)
	Combustion Turbine	4.9	5.6	12.2	12.4	7.2	8.9	7.3	29.1	29.1	29.1	29.1	29.1	29.1	28.8	-	-	-	-	-	-	-	-	-	-	-	-	-	(0.3)
	Steam Turbine	7.0	1.9	2.1	1.7	-	-	-	7.9	1.6	1.6	1.6	-	-	-	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(7.9)	(7.9)	(7.9)
	Fuel Oil	-	-	-	-	-	-	-	2.4	2.4	2.4	1.9	-	-	-	-	-	-	-	-	-	-	(4.7)	(4.7)	(4.7)	(5.2)	(7.1)	(7.1)	(7.1)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.8	11.8	11.8	11.9	11.8	11.9	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	57.6	233.3	363.7	385.3	427.4	521.3	11.3	31.8	122.2	204.7	221.7	253.7	375.7	-	14.6	101.5	179.1	194.2	226.2	348.2	-	-	-	-	-	-	-
	Wind	33.0	163.0	175.8	172.5	173.2	168.4	137.1	9.5	46.9	50.9	50.9	50.9	50.9	50.9	-	37.3	41.3	41.3	41.3	41.3	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	111.3	218.6	350.2	-	-	-	-	31.4	64.7	129.0	-	-	-	-	31.4	64.7	129.0	-	-	-	-	-	-	-
	Battery Storage	0.1	(0.2)	(1.9)	(8.6)	(13.2)	(23.7)	(57.5)	0.3	0.3	7.0	31.4	46.7	67.5	143.7	-	-	6.7	31.1	46.4	67.2	143.4	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(0.7)	(1.7)	(3.7)	(4.3)	(4.4)	(6.7)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.2	0.1	-	-	1.2	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	2.8	33.2	45.9	81.5	348.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Scenario	Resource Type	Annual Energy (TWh)							Installed Capacity (GW)							Cumulative Capacity Additions (GW)							Cumulative Capacity Retirements (GW)						
		2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
80% GHG Land Constrained	Nuclear	276.2	266.1	266.1	266.0	264.6	258.8	256.5	33.0	31.8	31.8	31.8	31.8	31.8	31.8	-	-	-	-	-	-	-	-	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
	Coal	176.3	127.2	7.2	-	-	-	-	51.3	30.8	1.6	-	-	-	-	-	-	-	-	-	-	-	-	(20.5)	(49.7)	(51.3)	(51.3)	(51.3)	(51.3)
	Combined Cycle	236.4	332.1	454.3	405.5	330.3	259.8	217.9	51.7	63.4	81.9	78.3	76.6	63.6	59.2	-	-	-	-	-	-	-	-	(1.3)	(1.3)	(4.9)	(6.6)	(19.6)	(23.9)
	Combustion Turbine	4.9	7.0	12.4	9.7	7.7	1.8	2.2	29.1	28.6	28.6	28.5	28.5	28.0	26.0	-	-	-	-	-	-	-	-	(0.6)	(0.6)	(0.7)	(0.7)	(1.2)	(3.2)
	Steam Turbine	7.0	2.1	2.1	0.3	0.2	-	-	7.9	1.6	1.6	1.6	1.6	-	-	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(6.3)	(7.9)	(7.9)
	Fuel Oil	-	-	-	-	0.0	-	-	1.7	1.7	1.7	1.4	0.6	-	-	-	-	-	-	-	-	-	(5.4)	(5.4)	(5.4)	(5.7)	(6.5)	(7.1)	(7.1)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.0	11.3	10.7	10.3	10.2	10.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	26.9	45.8	76.7	168.5	254.5	258.5	11.3	17.2	27.7	44.3	90.9	139.1	142.0	-	-	7.0	18.6	63.4	111.6	114.5	-	-	-	-	-	-	-
	Wind	33.0	33.4	33.4	88.3	105.0	104.4	103.9	9.5	9.7	9.7	25.4	30.3	30.3	30.3	-	-	-	15.7	20.6	20.6	20.6	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	20.5	125.8	-	-	-	-	-	5.6	35.5	-	-	-	-	-	5.6	35.5	-	-	-	-	-	-	-
	Battery Storage	0.1	0.0	0.1	(0.0)	(0.2)	(4.3)	(6.4)	0.3	0.3	0.3	0.3	0.5	14.5	20.5	-	-	-	-	0.2	14.2	20.2	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(1.0)	(0.8)	(1.2)	(2.0)	(2.4)	(2.5)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.2	0.4	0.9	9.5	3.7	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	0.1	6.9	10.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80% GHG Land Unconstrained	Nuclear	276.2	252.2	244.6	244.3	243.6	241.5	237.5	33.0	30.1	29.2	29.2	29.2	29.2	29.2	-	-	-	-	-	-	-	-	(2.9)	(3.8)	(3.8)	(3.8)	(3.8)	(3.8)
	Coal	176.3	117.9	-	-	-	-	-	51.3	30.8	-	-	-	-	-	-	-	-	-	-	-	-	-	(20.5)	(51.3)	(51.3)	(51.3)	(51.3)	(51.3)
	Combined Cycle	236.4	354.1	475.4	404.2	325.3	247.1	208.9	51.7	64.5	83.0	82.0	78.6	78.3	74.8	-	-	-	-	-	-	-	-	(0.2)	(0.2)	(1.2)	(4.6)	(4.9)	(8.4)
	Combustion Turbine	4.9	8.1	12.2	9.5	8.4	7.1	5.7	29.1	29.1	29.1	29.1	29.1	29.1	29.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Steam Turbine	7.0	2.0	2.0	0.6	0.3	0.0	-	7.9	1.6	1.6	1.6	1.6	0.1	-	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(6.3)	(7.8)	(7.9)
	Fuel Oil	-	-	-	-	0.0	-	-	1.7	1.7	1.7	1.0	0.6	-	-	-	-	-	-	-	-	-	(5.4)	(5.4)	(5.4)	(6.1)	(6.5)	(7.1)	(7.1)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.1	11.2	10.8	10.6	10.6	10.5	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	26.9	54.0	68.1	94.0	113.4	140.9	11.3	17.2	31.9	40.0	53.2	62.4	76.6	-	-	11.1	14.3	25.7	34.9	49.1	-	-	-	-	-	-	-
	Wind	33.0	33.4	33.4	120.3	205.0	295.8	371.0	9.5	9.7	9.7	30.6	55.3	82.2	104.7	-	-	-	21.0	45.6	72.6	95.1	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Battery Storage	0.1	0.1	0.1	(0.0)	(0.0)	(0.6)	(2.7)	0.3	0.3	0.3	0.3	0.3	2.1	8.8	-	-	-	-	-	1.8	8.5	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(1.0)	(1.0)	(1.4)	(2.0)	(2.5)	(2.2)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.2	0.1	0.3	0.3	0.2	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	0.0	0.3	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80% GHG New Firm, Carbon-Free	Nuclear	276.2	266.1	266.1	266.0	265.4	261.3	308.4	33.0	31.8	31.8	31.8	31.8	31.8	37.4	-	-	-	-	-	-	5.6	-	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
	Coal	176.3	127.2	7.3	-	-	-	-	51.3	30.8	1.6	-	-	-	-	-	-	-	-	-	-	-	-	(20.5)	(49.7)	(51.3)	(51.3)	(51.3)	(51.3)
	Combined Cycle	236.4	331.8	453.9	404.9	325.7	253.8	214.2	51.7	62.8	81.3	78.3	75.0	73.2	59.4	-	-	-	-	-	-	-	-	(1.9)	(1.9)	(4.9)	(8.2)	(10.0)	(23.8)
	Combustion Turbine	4.9	7.2	12.5	9.8	9.0	5.2	4.5	29.1	29.1	29.1	29.1	29.1	29.1	29.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Steam Turbine	7.0	2.1	2.1	0.4	0.3	-	-	7.9	1.6	1.6	1.6	1.6	-	-	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(6.3)	(7.9)	(7.9)
	Fuel Oil	-	-	-	0.0	0.0	-	-	1.7	1.7	1.7	1.6	0.6	-	-	-	-	-	-	-	-	-	(5.4)	(5.4)	(5.4)	(5.5)	(6.5)	(7.1)	(7.1)
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	11.0	11.3	10.7	10.6	10.6	10.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	18.1	26.9	46.0	72.5	106.7	208.2	233.8	11.3	17.2	27.7	41.8	59.6	111.1	125.4	-	-	7.0	16.2	32.1	83.6	97.9	-	-	-	-	-	-	-
	Wind	33.0	33.4	33.4	92.8	169.2	176.0	175.9	9.5	9.7	9.7	25.9	48.8	50.9	50.9	-	-	-	16.3	39.1	41.3	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	-	29.6	-	-	-	-	-	-	8.2	-	-	-	-	-	-	8.2	-	-	-	-	-	-	-
	Battery Storage	0.1	0.1	0.1	(0.0)	(0.1)	(2.6)	(5.5)	0.3	0.3	0.3	0.3	0.3	6.9	18.1	-	-	-	-	-	6.6	17.8	-	-	-	-	-	-	-
	Pumped Hydro	(1.5)	(1.0)	(0.9)	(1.3)	(1.6)	(2.0)	(2.6)	5.2	5.2	5.2	5.2	5.2	5.2	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	0.2	0.5	0.4	2.2	1.1	8.9	9.2	9.4	9.5	9.7	9.9	10.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	-	1.9	3.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Scenario	Resource Type	Annual Energy (TWh)							Installed Capacity (GW)						
		2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
100% GHG New Firm, Carbon-Free	Nuclear	276.2	266.0	266.1	264.8	366.7	506.6	565.6	33.0	31.8	31.8	31.8	43.9	61.6	71.2
	Coal	176.3	107.4	-	-	-	-	-	51.3	30.8	-	-	-	-	-
	Combined Cycle	236.4	327.9	380.0	275.6	172.1	66.1	12.6	51.7	56.6	75.1	72.4	60.8	36.1	20.1
	Combustion Turbine	4.9	11.5	9.1	7.3	4.8	2.0	1.0	29.1	28.3	28.3	28.3	28.3	28.3	27.2
	Steam Turbine	7.0	0.7	0.4	0.2	-	-	-	7.9	1.6	1.6	1.3	-	-	-
	Fuel Oil	-	-	-	-	-	-	-	0.8	0.8	0.8	-	-	-	-
	Other	29.1	29.0	29.0	29.0	29.0	29.0	-	3.3	3.3	3.3	3.3	3.3	3.3	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	11.1	10.7	10.7	10.3	10.5	10.3	10.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4
	Solar	18.1	30.5	77.0	127.7	157.2	155.5	184.0	11.3	18.8	43.0	69.4	85.1	85.6	107.2
	Wind	33.0	51.3	89.6	172.1	176.0	172.8	163.7	9.5	14.0	25.0	49.6	50.9	50.9	50.9
	Wind Offshore	-	-	-	-	-	-	33.7	-	-	-	-	-	-	10.5
	Battery Storage	0.1	0.0	0.0	(0.1)	(2.2)	(5.1)	(8.5)	0.3	0.3	0.3	0.3	4.4	16.2	29.4
	Pumped Hydro	(1.5)	(1.3)	(1.1)	(1.9)	(2.4)	(3.9)	(4.7)	5.2	5.2	5.2	5.2	5.2	5.2	5.2
	Demand Response	-	-	0.3	0.4	2.9	8.3	12.2	8.9	9.2	9.4	9.5	9.7	9.9	10.1
	Load	790.6	833.8	861.0	885.4	914.6	941.7	969.8	-	-	-	-	-	-	-
	Curtailment	-	-	-	0.0	1.4	7.3	34.5	-	-	-	-	-	-	-

Scenario	Resource Type	Cumulative Capacity Additions (GW)							Cumulative Capacity Retirements (GW)						
		2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
100% GHG New Firm, Carbon-Free	Nuclear	-	-	-	-	12.1	29.8	39.4	-	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
	Coal	-	-	-	-	-	-	-	-	(20.5)	(51.3)	(51.3)	(51.3)	(51.3)	(51.3)
	Combined Cycle	-	-	-	-	-	-	-	-	(8.1)	(8.1)	(10.8)	(22.4)	(47.1)	(63.1)
	Combustion Turbine	-	-	-	-	-	-	-	-	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(1.9)
	Steam Turbine	-	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.6)	(7.9)	(7.9)	(7.9)
	Fuel Oil	-	-	-	-	-	-	-	(6.3)	(6.3)	(6.3)	(7.1)	(7.1)	(7.1)	(7.1)
	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Carbon Capture & Sequestra	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Solar	-	1.7	22.2	43.8	57.6	58.1	79.7	-	-	-	-	-	-	-
	Wind	-	4.3	15.3	39.9	41.3	41.3	41.3	-	-	-	-	-	-	-
	Wind Offshore	-	-	-	-	-	-	10.5	-	-	-	-	-	-	-
	Battery Storage	-	-	-	-	4.1	15.9	29.1	-	-	-	-	-	-	-
	Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Demand Response	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Load	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Curtailment	-	-	-	-	-	-	-	-	-	-	-	-	-	-

7.7 Detailed RESOLVE Emissions and Cost Results[42]

	Annual Cost ($ billion)							Annual GHG Emissions (million metric tons)						
Scenario	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
Reference	$ 25	$ 23	$ 24	$ 26	$ 28	$ 30	$ 31	301	323	324	337	350	356	346
BAU	$ 25	$ 25	$ 27	$ 30	$ 32	$ 34	$ 36	305	306	285	288	295	297	279
BAU No Carbon Price	$ 25	$ 24	$ 26	$ 29	$ 32	$ 33	$ 34	302	316	270	269	272	270	257
BAU System Carbon Price	$ 25	$ 25	$ 27	$ 30	$ 32	$ 34	$ 35	300	268	178	173	171	161	128
BAU Tech Neutral	$ 25	$ 24	$ 25	$ 27	$ 30	$ 31	$ 32	301	314	281	295	299	297	286
60% GHG	$ 25	$ 24	$ 24	$ 26	$ 29	$ 31	$ 32	301	286	226	226	205	185	164
80% GHG	$ 25	$ 24	$ 25	$ 27	$ 30	$ 34	$ 37	301	276	205	175	144	113	82
90% GHG	$ 25	$ 25	$ 25	$ 28	$ 32	$ 38	$ 43	301	266	185	149	113	77	41
100% GHG	$ 25	$ 25	$ 26	$ 30	$ 36	$ 45	$ 56	301	255	164	123	82	41	0
Low CES	$ 25	$ 24	$ 24	$ 26	$ 29	$ 31	$ 32	301	286	226	223	204	181	167
Mid CES	$ 25	$ 24	$ 25	$ 27	$ 30	$ 33	$ 36	301	279	205	181	153	121	83
High CES	$ 25	$ 24	$ 26	$ 29	$ 34	$ 42	$ 53	301	280	165	133	95	56	10
60% RPS	$ 25	$ 25	$ 26	$ 29	$ 32	$ 35	$ 39	301	292	211	202	188	192	154
80% RPS	$ 25	$ 26	$ 28	$ 32	$ 37	$ 43	$ 49	301	276	178	174	152	121	77
100% RPS	$ 25	$ 27	$ 30	$ 37	$ 46	$ 56	$ 80	301	256	162	139	101	60	9
80% GHG Land Constrained	$ 25	$ 24	$ 25	$ 27	$ 31	$ 36	$ 39	301	276	205	175	144	113	82
80% GHG Land Unconstraine	$ 25	$ 24	$ 24	$ 27	$ 30	$ 32	$ 33	301	276	205	175	144	113	82
80% GHG New Firm, Carbon-	$ 25	$ 24	$ 25	$ 27	$ 30	$ 34	$ 36	301	276	205	175	144	113	82
100% GHG New Firm, Carbo	$ 25	$ 25	$ 26	$ 30	$ 35	$ 42	$ 50	301	255	164	123	82	41	0

	Carbon-Free Energy (%)							Average Retail Rate ($/kWh)						
Scenario	2020	2025	2030	2035	2040	2045	2050	2020	2025	2030	2035	2040	2045	2050
Reference	43%	28%	23%	24%	24%	25%	30%	$ 0.11	$ 0.10	$ 0.10	$ 0.10	$ 0.11	$ 0.11	$ 0.11
BAU	43%	35%	42%	44%	47%	49%	53%	$ 0.11	$ 0.10	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11
BAU No Carbon Price	43%	31%	32%	35%	38%	40%	45%	$ 0.11	$ 0.10	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11
BAU System Carbon Price	43%	42%	48%	51%	53%	57%	66%	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11
BAU Tech Neutral	43%	31%	32%	31%	34%	36%	41%	$ 0.11	$ 0.10	$ 0.10	$ 0.11	$ 0.11	$ 0.11	$ 0.11
60% GHG	43%	38%	37%	38%	43%	50%	56%	$ 0.11	$ 0.10	$ 0.10	$ 0.10	$ 0.11	$ 0.11	$ 0.11
80% GHG	43%	40%	41%	50%	60%	70%	78%	$ 0.11	$ 0.10	$ 0.10	$ 0.11	$ 0.11	$ 0.11	$ 0.11
90% GHG	43%	40%	46%	57%	69%	79%	89%	$ 0.11	$ 0.10	$ 0.10	$ 0.11	$ 0.11	$ 0.12	$ 0.12
100% GHG	43%	43%	51%	65%	77%	90%	98%	$ 0.11	$ 0.10	$ 0.11	$ 0.11	$ 0.12	$ 0.12	$ 0.13
Low CES	43%	38%	37%	38%	44%	52%	56%	$ 0.11	$ 0.10	$ 0.10	$ 0.10	$ 0.11	$ 0.11	$ 0.11
Mid CES	43%	40%	42%	49%	58%	68%	78%	$ 0.11	$ 0.10	$ 0.10	$ 0.11	$ 0.11	$ 0.11	$ 0.11
High CES	43%	40%	52%	63%	75%	87%	100%	$ 0.11	$ 0.10	$ 0.11	$ 0.11	$ 0.11	$ 0.12	$ 0.13
60% RPS	43%	37%	41%	46%	52%	53%	61%	$ 0.11	$ 0.10	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.12
80% RPS	43%	42%	50%	53%	59%	69%	81%	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.12	$ 0.12	$ 0.13
100% RPS	43%	48%	55%	62%	75%	88%	105%	$ 0.11	$ 0.11	$ 0.11	$ 0.12	$ 0.13	$ 0.14	$ 0.16
80% GHG Land Constrained	43%	40%	41%	50%	60%	69%	78%	$ 0.11	$ 0.10	$ 0.10	$ 0.11	$ 0.11	$ 0.11	$ 0.12
80% GHG Land Unconstraine	43%	39%	40%	50%	60%	70%	78%	$ 0.11	$ 0.10	$ 0.10	$ 0.11	$ 0.11	$ 0.11	$ 0.11
80% GHG New Firm, Carbon-	43%	40%	41%	50%	60%	70%	78%	$ 0.11	$ 0.10	$ 0.10	$ 0.11	$ 0.11	$ 0.11	$ 0.11
100% GHG New Firm, Carbo	43%	43%	51%	65%	78%	90%	99%	$ 0.11	$ 0.10	$ 0.11	$ 0.11	$ 0.11	$ 0.12	$ 0.13

[42] Annual Cost represents going-forward costs of system power generation, fuel, and losses, but does not incorporate costs of transmission and distribution.