Duke NICHOLAS INSTITUTE *for* ENERGY, ENVIRONMENT & SUSTAINABILITY

Planning for Growing Electricity Demand During an Era of Uncertain Renewables and Climate Policy

Martin Ross, Jackson Ewing, Brian Murray, Tim Profeta, Robert Stout, and Michael Yoo

Authors and Affiliations

Martin Ross, Nicholas Institute for Energy, Environment & Sustainability, Duke University
Jackson Ewing, Nicholas Institute for Energy, Environment & Sustainability, Duke University
Brian Murray, Nicholas Institute for Energy, Environment & Sustainability, Duke University
Tim Profeta, Nicholas Institute for Energy, Environment & Sustainability, Duke University
Robert Stout, Nicholas Institute for Energy, Environment & Sustainability, Duke University
Michael Yoo, Nicholas Institute for Energy, Environment & Sustainability, Duke University

Citation

Ross, M, J. Ewing, B. Murray, T. Profeta, R. Stout, and M. Yoo. 2024. *Planning for Growing Electricity Demand During an Era of Uncertain Renewables and Climate Policy*. NI R 24-06. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University. https://nicholasinstitute.duke.edu/ publications/planning-growing-electricity-demand-during-era-uncertain-renewables-and-climate-policy.

Cover image courtesy National Renewable Energy Laboratory.

Nicholas Institute for Energy, Environment & Sustainability

The Nicholas Institute for Energy, Environment & Sustainability at Duke University accelerates solutions to critical energy and environmental challenges, advancing a more just, resilient, and sustainable world. The Nicholas Institute conducts and supports actionable research and undertakes sustained engagement with policymakers, businesses, and communities—in addition to delivering transformative educational experiences to empower future leaders. The Nicholas Institute's work is aligned with the Duke Climate Commitment, which unites the university's education, research, operations, and external engagement missions to address the climate crisis.

Contact

Nicholas Institute | Duke University | P.O. Box 90467 | Durham, NC 27708
1201 Pennsylvania Avenue NW | Suite 500 | Washington, DC 20004
919.613.1305 | nicholasinstitute@duke.edu

CONTENTS

ABSTRACT

Electricity demand growth has accelerated significantly, a trend that is expected to continue for at least the next 5 to 10 years and is driven by new technologies such as data centers and the expansion of the manufacturing and industrial base in the United States. This demand growth is anticipated at a time when connecting new generating resources to the grid, particularly renewables, and expanding transmission has never been more difficult. New emissions rules for existing coal and new gas units (the EPA Final Greenhouse Gas [GHG] Rule) will also create additional pressure toward clean generation on the system.

This analysis uses a variety of integrated resource plans (IRPs) from utilities and other groups to estimate how overall electricity demand may change over the next decade. The trends are then analyzed using an electricity capacity-planning-and-dispatch model to evaluate how the US system may respond in a world of high demand growth. The findings suggest that additional electricity needs are likely to be met with a combination of new natural-gas and renewables capacity. Limitations on the ability of the system to incorporate renewables may place significant upward pressure on emissions, as would repeal of parts or all of the GHG rules.

INTRODUCTION

Growth in the demand for electricity has accelerated significantly over the last several years, driven in part by emerging technologies such as data centers and the reshoring of manufacturing after passage of the Inflation Reduction Act (IRA) in 2022. After decades of relatively flat electricity demand, grid planners are now anticipating that over the next five years or more this recent growth will continue at rates double what was anticipated just a few years ago (Wilson and Zimmerman 2023).

Data centers alone, which provide the cloud support required for businesses and artificial intelligence, could potentially consume more than 9% of all US electricity generation by 2030, up from 4% in 2023. As of 2023, a dozen states saw more than 4 TWh of electricity demand from data centers, already representing more than 10% of total demand in six of those states—and more than 25% in Virginia (EPRI 2024). Concentration of these new data center and industrial demands in a few regions of the country (EPRI 2024; OnLocation 2024) may place additional stresses on local grids as overall demand rises.

This demand growth is expected at a time when delays in connecting new resources to the grid, particularly renewables and storage, have never been longer. Rand et al. (2024) estimate that there is currently 1,570 GW of generator capacity (~95% of which is zero-carbon) and 1,030 GW of storage capacity waiting in interconnection queues to be added to the grid. They also state that the average time a project spends in the queue as of 2023 is nearly five years, up from three years in 2018 and less than two years in 2008. Partly as a result of these delays, project completion rates are typically low—on the range of 14% for solar and 11% for batteries.

Higher-than-anticipated electricity demand growth will also occur in a world where new and existing fossil units face additional emissions requirements. In April 2024, the EPA announced the Final Greenhouse Gas (GHG) Rule that sets pollution standards for existing coal-fired and new gas-fired power plants, based on Section 111 of the Clean Air Act. Coal units anticipating long-term operation (i.e., beyond 2038) must meet an emissions rate consistent with 90% carbon capture and storage (CCS) by 2032. A few coal units intending to operate only up to the end of 2038 must have an emissions rate consistent with 40% gas cofiring by 2030, while coal plants retiring by 2032 are exempt from the GHG rule. New natural gas plants are separated into three categories by the rule: baseload units operating more than 40% of the time, intermediate load units running at between a 20% and 40% utilization rate, and peaking units running at less than 20% of capacity. New baseload gas has to install CCS retrofits by 2032, while the other two types must merely operate efficiently.

Against the backdrop of potential limitations on the ability to bring renewables into the system and new emissions requirements, this analysis looks at the impacts of high anticipated demand growth. A variety of forecasts from utilities' and states' integrated resource planning (IRP) documents, along with other state and regional estimates, are used to establish potential demand trends for this modeling. This more aggressive IRP forecast with high growth is compared in the analysis to electricity demand based on older Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2023 (EIA 2023a) data with slower growth rates. Sensitivities are done to evaluate potential impacts of limitations on the ability of developers to connect renewables to the grid, natural gas prices, and the implications of any repeal of parts or all of the recent EPA Final GHG Rule.

The analysis is conducted using the Dynamic Integrated Economy/Energy/Emissions Model (DIEM). While the model includes a broad macroeconomic component, this work is done using solely the detailed electricity dispatch component of DIEM to facilitate use of the externally generated IRP forecasts for electricity demand. The electricity model is a representation of US wholesale electricity markets and builds on work performed with the DIEM model regarding technology adoption and interactions with climate-related policies (Ross et al. 2023; Ewing et al. 2022; Konschnik et al. 2021; Ross 2018, 2019; Ross and Murray 2016; Murray et al. 2015). The model represents intermediate- to long-run decisions of the industry regarding generation, transmission, capacity planning, and dispatch of units. To estimate impacts, it minimizes electricity generation costs while meeting electricity demand and environmental policy goals.

Although this analysis provides specific estimates of investments, generation, and emissions for each model scenario, it is important to view the findings more broadly and evaluate overall trends and insights that can be gleaned from the results, rather than focus on specific numbers. The next subsection summarizes overall highlights of the analysis, followed by some background information and a more comprehensive description of the model and assumptions used, and then details regarding the results across a range of scenarios about the future.

Highlights of the Analysis

This section provides a brief overview of findings suggested by the modeling in this analysis. Keep in mind that these results are—to a greater or lesser degree—an outcome of the assumptions used in the analysis about demand growth rates, natural gas prices, the ability of the system to install renewable capacity, and potential policy choices. In the subsequent sections, additional details regarding the implications of these alternative are discussed.

Impacts of Demand Growth on US Emissions

- Even if renewables can be added to the grid at twice the highest rate seen in the historical data, growth in electricity demand of over 1.5% per year over the next decade could lead to emissions that are 30% higher by 2035 than was anticipated based on demand growth from the AEO forecasts of a few years ago.
- If new renewable capacity can only be installed at similar annual rates to those seen in the past, instead of more quickly, emissions could be an additional 25% higher in 2035.
- While any potential repeal of the Section 111(b)-type provisions in the EPA Final GHG Rule related to new combined-cycle units has comparatively modest effects on emissions (+5% in 2035), a full repeal of the GHG rule's provisions including those related to existing coal could leave emissions 50% higher than they would have been by 2035.

Impacts of Demand Growth on US Fossil Capacity and Generation

- Coal units are somewhat less likely to retire in the next five years if demand growth is high. However, by 2032 the provisions of the GHG rules mean that any remaining coal is largely retrofitted with CCS regardless of demand growth.
- Higher demand growth over the next five years leads to an additional 20 GW of combined-cycle units and 20 GW of combustion turbines. Beyond 2030, the gas fleet continues to expand more rapidly if demand growth is high.
- Under EPA's Final GHG Rules, new combined-cycle units are inclined to run at 40% utilization rates rather than install much CCS.
- Unlike what might be expected, lower natural gas prices do not necessarily lead to a significant expansion of new gas capacity, in part because the existing gas units run more.
- Even though removal of Section 111(b) has a limited effect on overall emissions, combined-cycle capacity is 40 GW higher by 2035 than it would have been otherwise.
- Up to 40 GW of existing coal is inclined to retrofit with CCS by 2032 (no non-retrofitted coal plants are economical by 2032), regardless of demand growth. However, if GHG rules for these coal units were eliminated, only 25 GW would choose to retrofit with CCS (due to the IRA subsidies) while another 60 GW would run uncontrolled in this situation.

Impacts of the Availability of Renewables on Capacity Investments

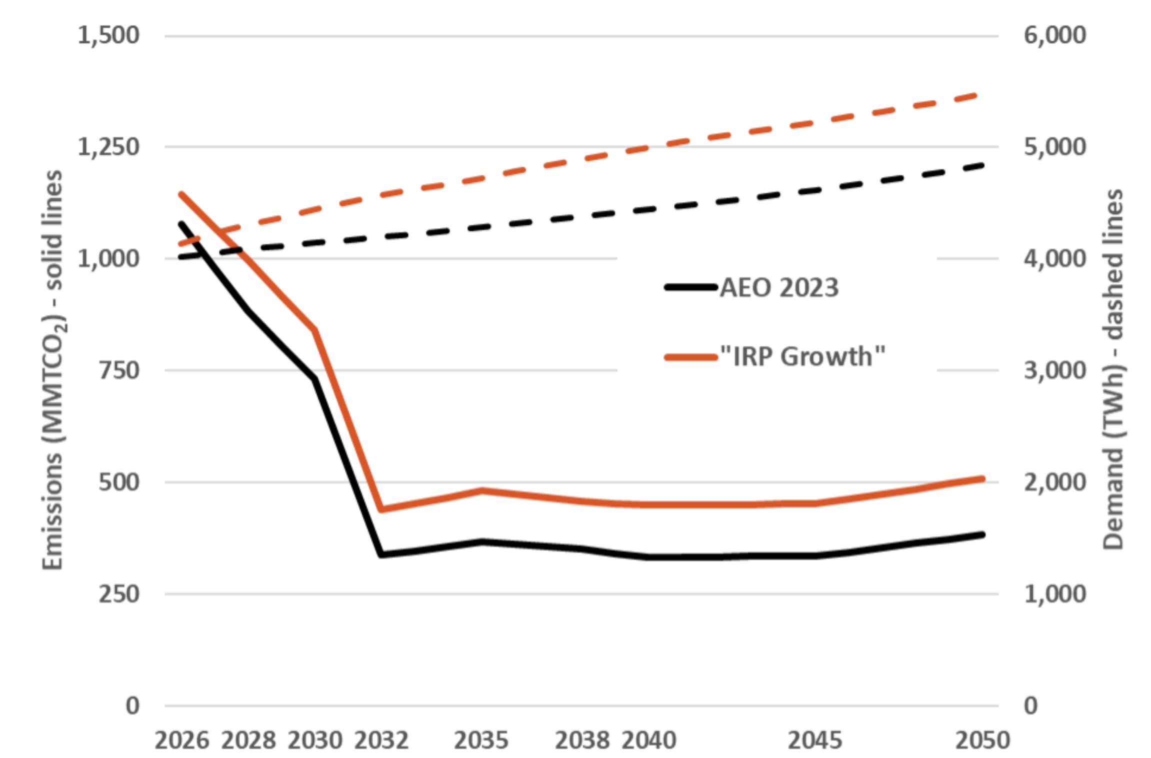
- Limitations on the rate at which renewables can be added to the grid has large effects on capacity choices in those regions with both high demand growth and high potential access to renewable resources.
- Any restrictions on renewables lead to a shift into new combined-cycle capacity, along with an increase in generation from existing gas units.
- Reduced investments in renewables as the result of delays in the interconnection queues—or perhaps local opposition—has more impact on emissions than a potential repeal of the Section 111(b)–related requirements of the GHG rules for new combined-cycle units (the same is not true for requirements related to existing coal).

SUMMARY OF THE ANALYSIS FINDINGS

Carbon dioxide (CO_2) emissions from electricity generation have been trending downwards for two decades as the result of coal plant retirements, a switch to natural gas generation, and the expansion of renewables in the system. Between 2005 and 2023, emissions fell by more than 40% from around 2,400 to 1,420 $MMTCO_2$ (EIA 2023c). The passage of the IRA in 2022 with its subsidies for renewable generation—among many other features—is accelerating these trends (see Ross et al. 2023). More recently, EPA's Final GHG Rules (EPA 2024a), which places conditions on existing coal and new natural gas plant operations, is also expected to lead to significant reductions in emissions—see the findings in the Model Results section later in this paper showing the impacts of a potential repeal of the EPA's GHG rules for new and existing fossil units.

Figure 1 has two emissions forecasts from the DIEM model based on either (1) the demand growth trends in the AEO 2023 or (2) the IRP growth scenario, which is described in more detail in the Model Structure And Data section. Emissions are shown on the left-hand vertical axis as solid lines, and corresponding demand growth is shown on the right-hand axis in dashed lines. Both emissions forecasts include the effects of EPA's GHG rules and the renewables subsidies in the IRA. Although the reductions through 2032 are dramatic as the industry attempts to take advantage of the IRA subsidies, it is possible that the current interconnection queues will reduce the ability of the system to bring solar, storage, and wind

Figure 1. US CO_2 emissions forecasts versus electricity demand trends



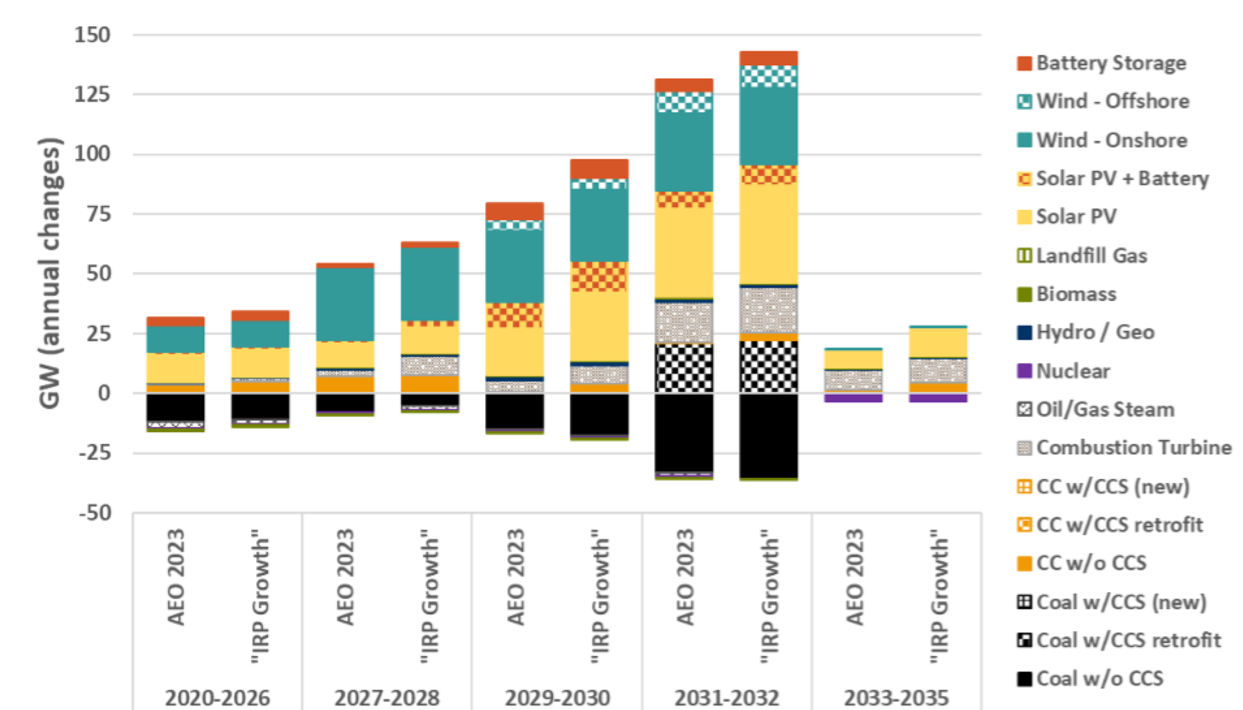
Source: DIEM model, EIA (2023a), authors' calculations based on the EIA AEO 2023 and various other forecasts.

projects online over the next several years—which would limit the near-term emissions reductions shown in Figure 1. (Figure 5 examines how a reduction in the amount of solar and wind installed over the next 5 to 10 years may affect emissions.)

Demand in the growth forecast based on the collected IRP plans and other forecasts is around 5% higher by 2028 than it was in the older AEO 2023 forecast. This difference increases to 10% by 2035, after which the differences between the two forecasts remain relatively constant. This occurs because of the focus of most IRPs on the next decade for planning purposes, rather than necessarily reflecting an expectation that longer term growth will stabilize. This higher demand growth over the next 5 to 10 years results in emissions that are around 15% higher in 2032 and more than 30% higher by 2035.

Figure 2 looks at the capacity changes in the United States under the lower-growth AEO 2023 forecast compared to the higher-growth IRP forecast. In Figure 2, the first time period shown (2020–2026) includes a combination of historical capacity additions and firm committed units, along with a small amount of new construction determined by the model to be economic in the first model run year of 2026. However, most actions are already predetermined during past years or through ongoing construction or currently anticipated units. By 2028, more expansion is feasible and, in the higher-growth scenario, the additional instal-

Figure 2. US annual capacity investments



Source: DIEM model.

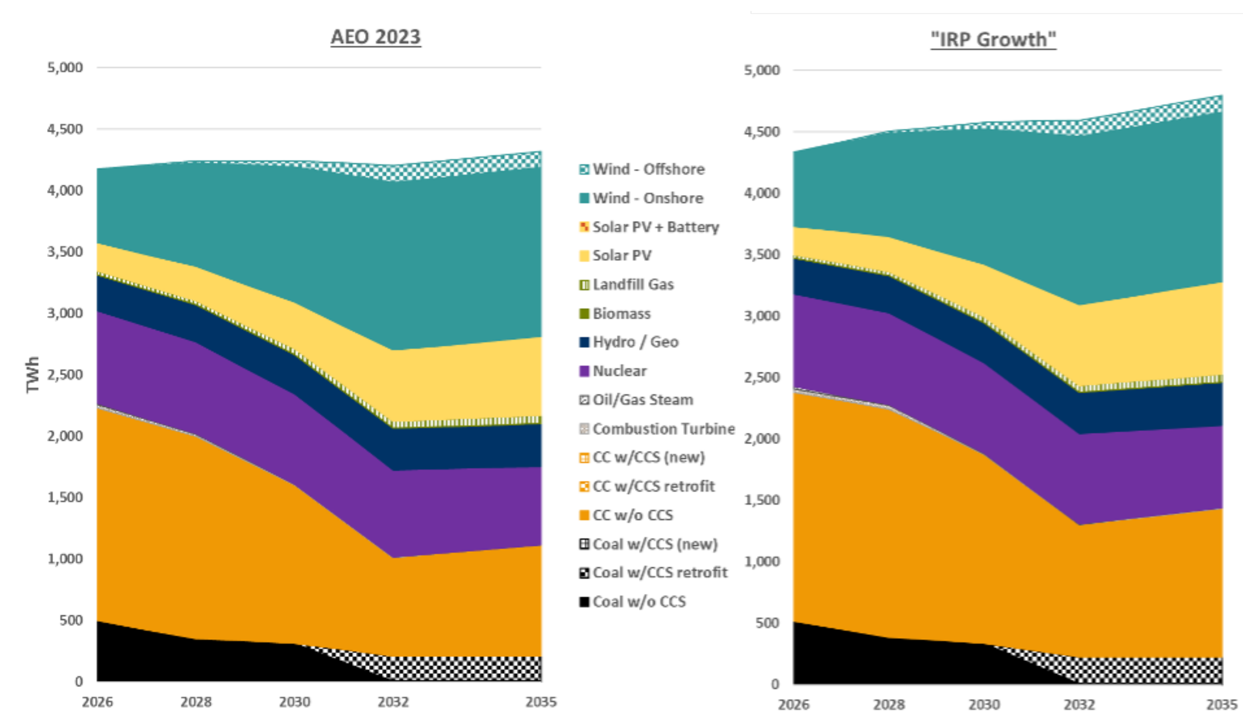
Notes: Based on the capital costs shown in the AEO 2023 ($6,500/kW in 2035 and $5,500/kW in 2050), small modular nuclear reactors are not selected in the modeling as an economic option for responding to high-demand growth.

lations focus on combustion turbines, some solar units with and without battery backup, alongside fewer coal retirements than were seen with lower demand growth. By 2030 and through 2032–2035, the resources used to supply the extra electricity are largely a combination of new combined-cycle units (running at 40% of capacity to avoid the CCS requirements in the GHG rules)1 and additional solar capacity investments.

Generation patterns follow the capacity adjustments but, given the different utilization rates of fossil and nuclear generation compared to renewables, it can still be illustrative to examine overall generation associated with the capacity additions and retirements from Figure 2. In Figure 3, as might be anticipated from the emissions differences between the AEO 2023 and IRP scenarios, the largest expansion in generation in response to higher demand growth is from combined-cycle units. Solar generation also expands as its capacity grows, while the existing coal units run at higher utilization rates through 2030, prior to any remaining units retrofitting with CCS in 2032.

How new renewables—and other new capacity—are distributed across regions of the country can vary significantly, depending on expected demand growth and the types of resources available in different states. Figure 4 looks at cumulative investments and retirements between 2020 and 2035 across nine regions of the country (see Figure 11 for regional defi-

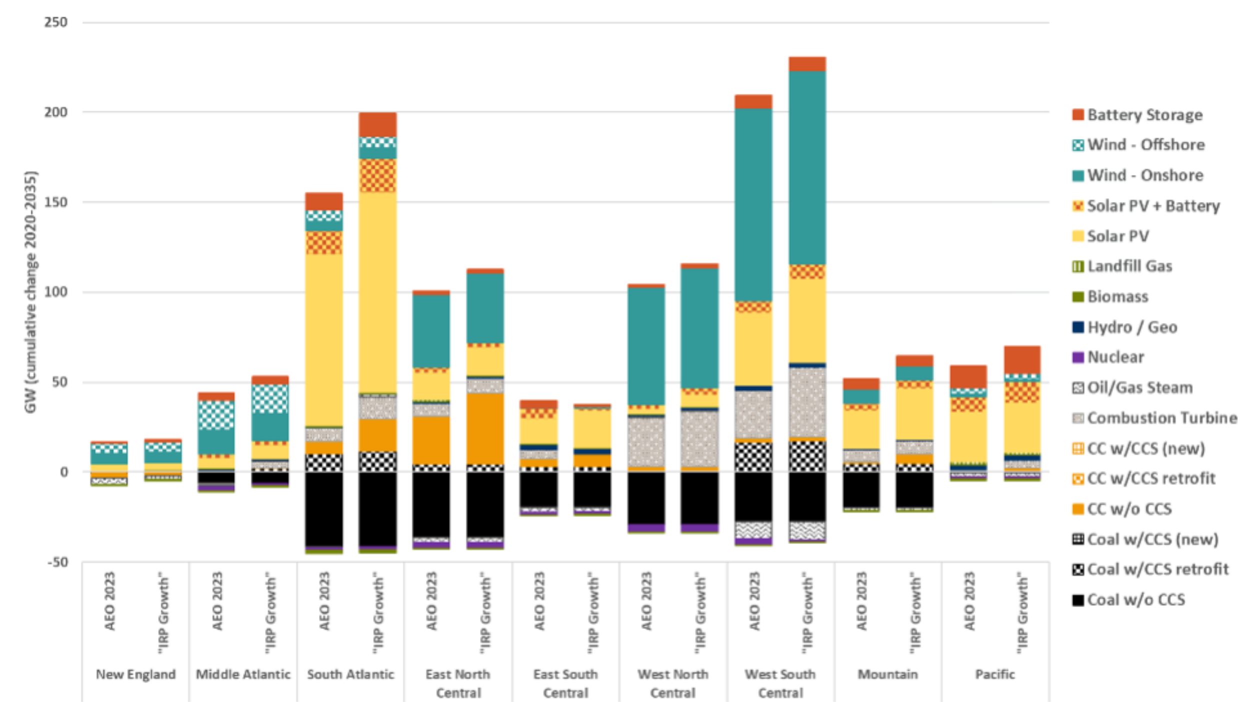
Figure 3. US total generation



Source: DIEM model.

1 See Figure 18 for an illustration of how new combined-cycle units respond under different GHG rules.

Figure 4. Regional cumulative capacity investments (2020–2035)



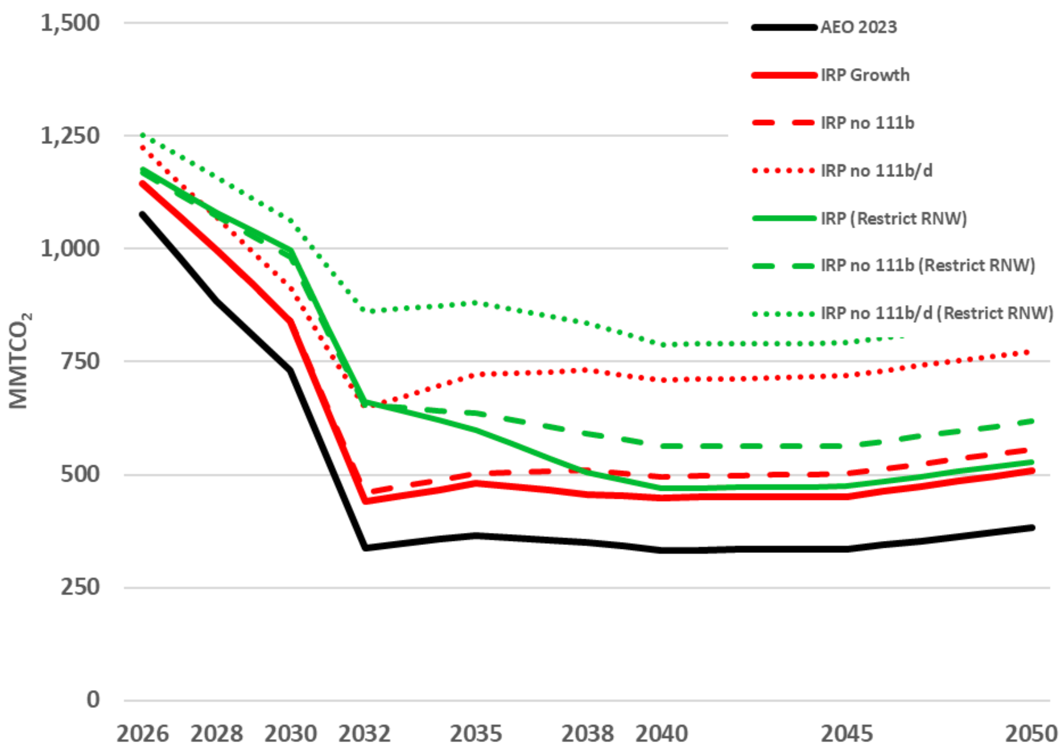
Source: DIEM model.

Notes: For illustrative purposes, state-level results from DIEM are aggregated into nine EIA Census regions.

nitions). As the figure shows, although the higher demand growth in the IRP forecasts is spread across the country, some regions have more extensive needs for additional capacity. The South Atlantic region, which includes states such as Georgia, North Carolina, and Virginia with high expected growth in demand from data centers, adds more combined-cycle capacity than would be needed without the higher growth. In absolute terms (see Figure 8), the West South Central and Mountain regions have some of the highest growth overall and tend to respond to this growth with a combination of gas and solar capacity.

Figure 5 contrasts emissions from the main growth scenarios in Figure 1 to several alternative sets of assumptions regarding future policies to see how sensitive emissions may be to a particular realization of the future. The dashed red lines (third from bottom) show how much emissions might increase if part or all of the current EPA GHG rules repealed. The IRP no 111(b) emissions suggest that removing the Section 111(b) New Source rules related to utilization rates and/or CCS for gas combined-cycle units would have a moderate upward pressure on emissions. This modest implied competition between natural gas and renewables is lower than might have been seen in older analyses because continuing declines in renewables costs have made them more cost effective relative to natural gas. However, if the parts of the Final GHG Rule related to Section 111(d) were repealed (IRP no 111[b]/[d]), the extended presence of coal units that are currently required to either retire or retrofit with CCS under the GHG rule as written would have a much more significant impact on emissions.

Figure 5. US CO_2 emissions forecasts across alternative scenarios



Source: DIEM model.

Similarly, the ability to construct renewables and connect them to the grid can have a dramatic effect on expected emissions. The main IRP Growth scenario adopts the relatively optimistic assumption that it is possible to install up to 30 GW of wind and 50 GW of solar annually between today and 2030 (i.e., twice the highest annual installations seen in the past, if these units are justified based on their economics). If wind and solar can only achieve—at most—the highest annual installation rates seen in the past (~15 GW for wind and ~30 GW for solar in the Restrict RNW scenarios), the near-term emissions reductions under a higher demand growth scenario would be substantially reduced.[2] If the ability to connect renewables (whether because of delays in the interconnection queues or other factors such as local opposition to siting) is combined with repeal of part or all of the EPA Final GHG Rules, emissions remain much higher throughout the future forecast.

BACKGROUND INFORMATION

This section provides additional detail on the demand forecasts used in this analysis. It also presents data on historical renewables installation patterns that are used to establish near-term boundaries for what is allowed in the DIEM model forecasts.

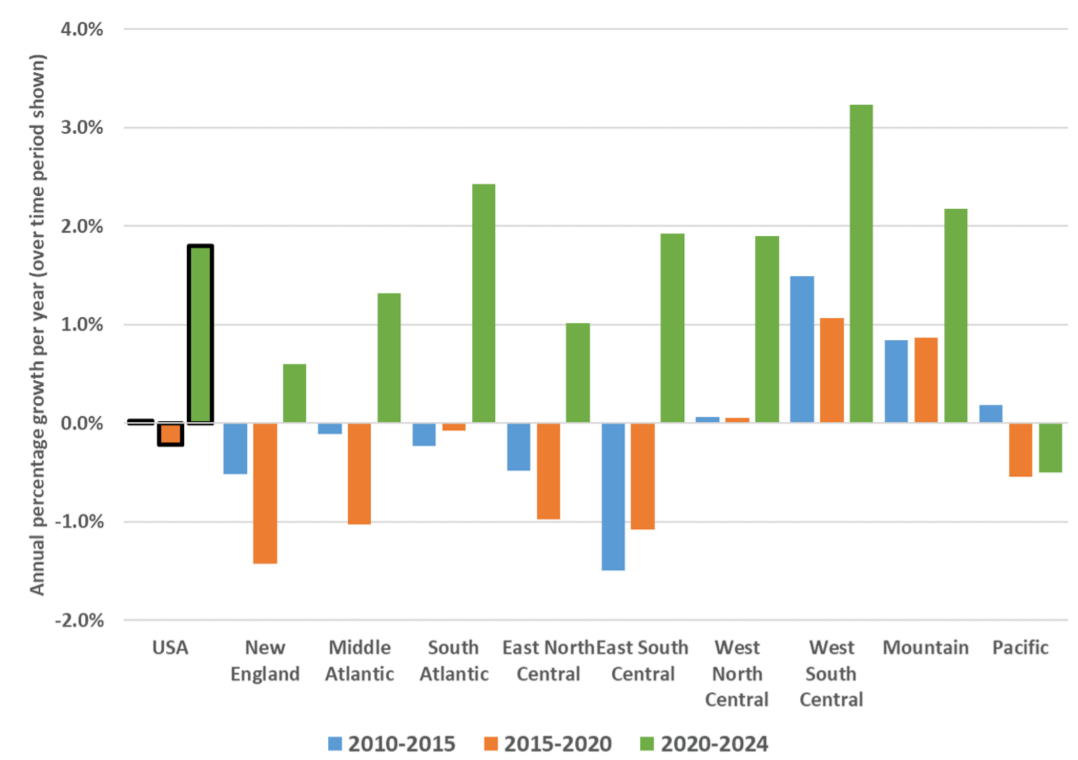
2 The modeling assumes these limitations on renewables installations are reduced over time, leading to the convergence of emissions trends between this Restricted case and the original IRP Growth forecast by 2040.

Demand Growth Forecasts

Historically, electricity demand growth in the United States has been low—less than 1% per year over the last 15 years. Figure 6 summarizes past annual average growth rates in electricity demand from January 2010 through June 2024 for nine groups of states. Note that while the dates chosen for specific columns in the figure can influence their appearance, the recent trends are relatively apparent, with growth accelerating in many regions since the beginning of the current decade (the last four years with high growth do include both the effects of new sources of demand such as data centers and one-time events such as economic recovery after the COVID-19 pandemic). Aside from the West Coast, where demand has varied quite a bit from year to year, the rest of the country has seen positive growth during the 2020s. Many regions have experienced growth near or above 2% per year, which is significantly higher than in the past.

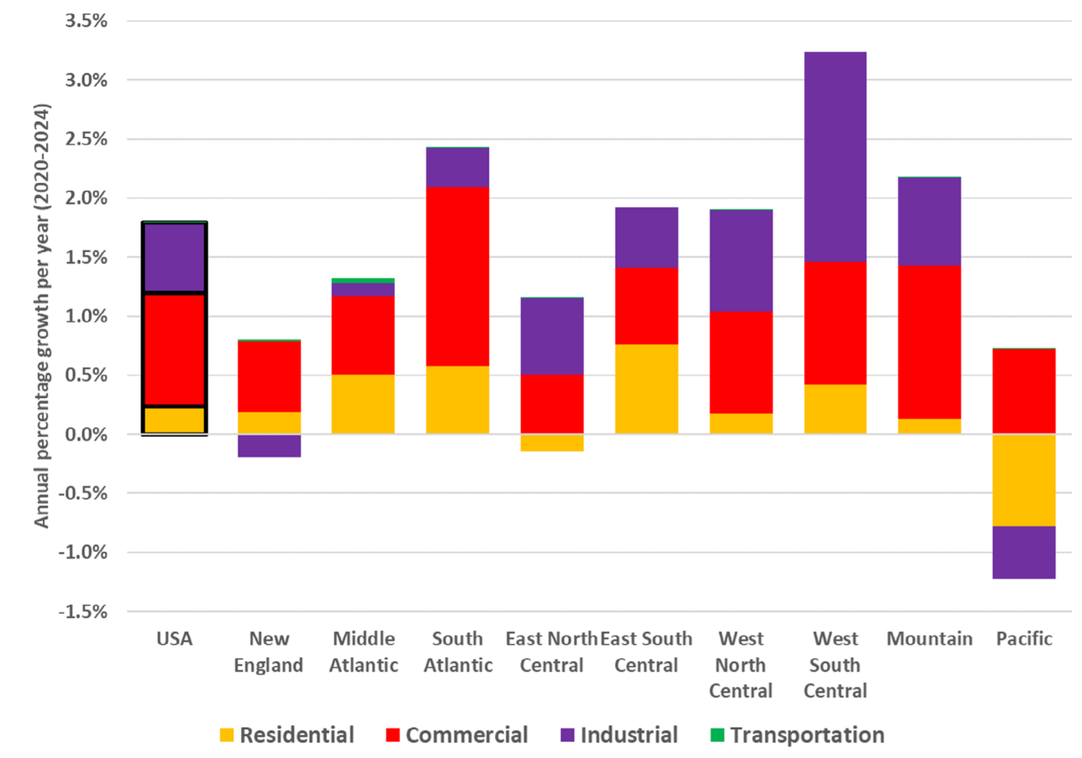
Figure 7 separates the most recent demand growth into the EIA's four economic sectors: residential, commercial, industrial, and transportation. When interpreting these data, note that data centers are in the commercial sector. Regions such as the South Atlantic—which includes Virginia, the Carolinas, and Georgia—has had most of their recent growth occurring in this commercial sector. Other regions see growth in a combination of the industrial and/or commercial sectors; in most regions, the residential sector contributes the least to demand growth. Transportation has not (yet) contributed to overall demand growth in a measurable way.

Figure 6. Annual average growth rates (January 2010 to June 2024)



Source: Authors' calculations based on EIA (2023c, 2024).

Figure 7. Sector shares of regional demand growth (average rates, 2020 to 2024)



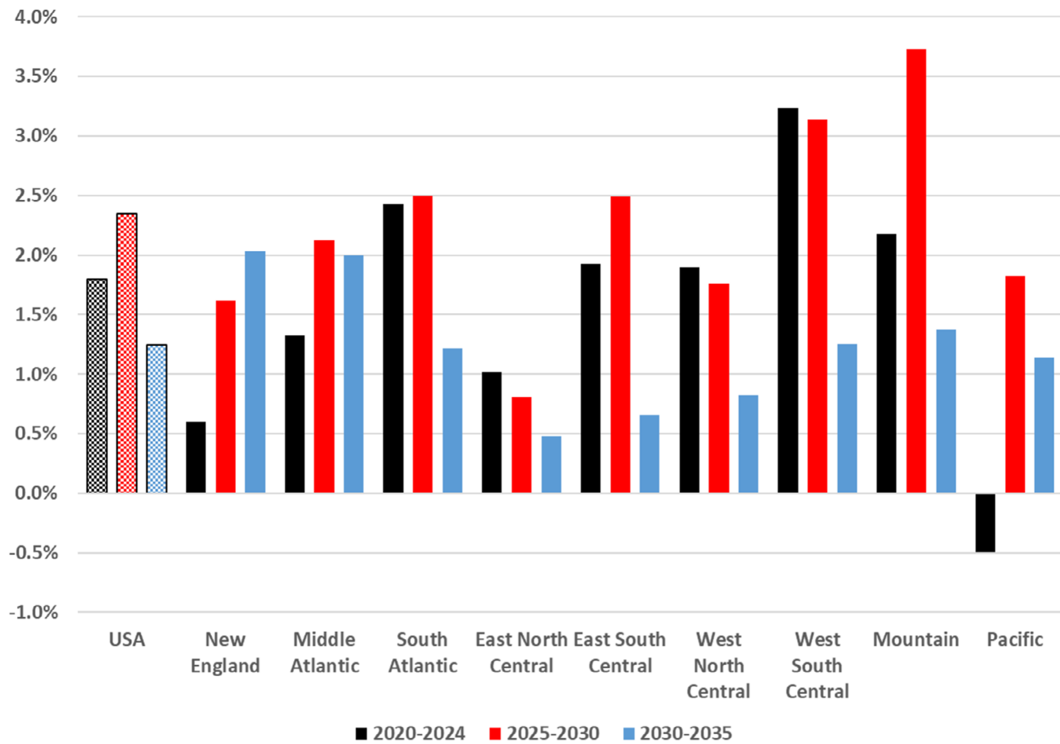
Source: Authors' calculations based on EIA (2023c, 2024).

Notes: See Figure 6 for total annual averages.

Figure 8 contrasts the most recent historical demand growth to an aggregation of the growth rates seen in state and utility planning forecasts from around the country. The forecasts have been collected from available IRPs and other state and regional forecasts (see Table A-7 for a partial list). The various forecasts provide somewhat different timeframes and different variables, which makes consistency an issue. Some data sources have information on electricity demand growth, either totals or by sector, as well as growth in peak demand; some have only a single peak growth forecast since the peaks tend to control capacity planning; and some are short-term (e.g., to 2030), many run through around 2035, and a few go beyond 2035.

Figure 8 combines these forecasts into overall regional growth forecasts. In the figure, the black (leftmost in each category) bars repeat the most recent historical growth from Figure 7. The red (middle) bars contrast this historical growth to near-term expectations from the IRP and other forecasts through 2030. The blue (right) bars show growth from 2030 through 2035 from available sources. Over the next five years, demand growth remains high, particularly when compared to the trends between 2010 and 2020. After 2030, growth expectations are lower, whether because the planning forecasts are largely concerned with the next five years or because growth (excluding impacts of any potential longer-term climate policies) is expected to decline.

Figure 8. IRP forecasts of demand growth versus recent trends

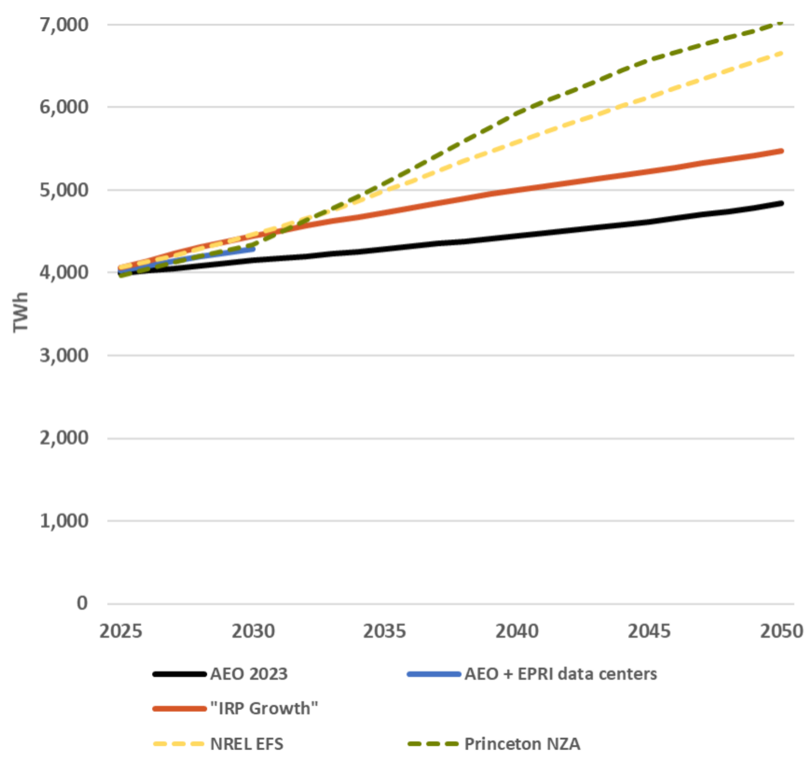


Source: Authors' calculations based on a collection of growth forecasts (see Table A-7) and EIA (2023c, 2024).

Figure 9 compares the national electricity demand growth from the AEO 2023 to an overall estimated forecast from the utility IRP reports and other sources. Over the next 10 to 15 years, the IRP forecasts (labeled "IRP Growth") grow at a significantly higher rate—2.1% per year through 2030 and 1.7% per year through 2035—than the trends originally expected in the AEO 2023 forecast—0.9% through 2030 and 0.8% through 2035. As an illustration of the potential impacts solely of data centers on overall demand, the AEO+EPRI forecast combines the AEO 2023 forecast with information from a report produced by EPRI (2024) that has detailed state-level estimates of electricity demand by data centers through 2030 (this increment demand over the AEO 2023 levels is shown by the blue line).

For comparison purposes, Figure 9 also includes estimates of the incremental demand from the electrification and climate policy studies by the National Renewable Energy Laboratory (Mai et al. 2018) and Princeton (Larson et al. 2021) over their respective reference cases. Through the early 2030s, both of these past studies are comparable to currently expected growth from the IRP forecasts without any of the policy drivers considered by NREL and Princeton. After the early 2030s, the IRP Growth trend cannot keep up with these two studies, which were looking at much broader long-term climate and electrification policies than are the focus of short-term IRP forecasts. The fact that these trends overlap at all illustrates how much expectations of demand growth have shifted since these studies were conducted.

Figure 9. US demand growth projections from various studies



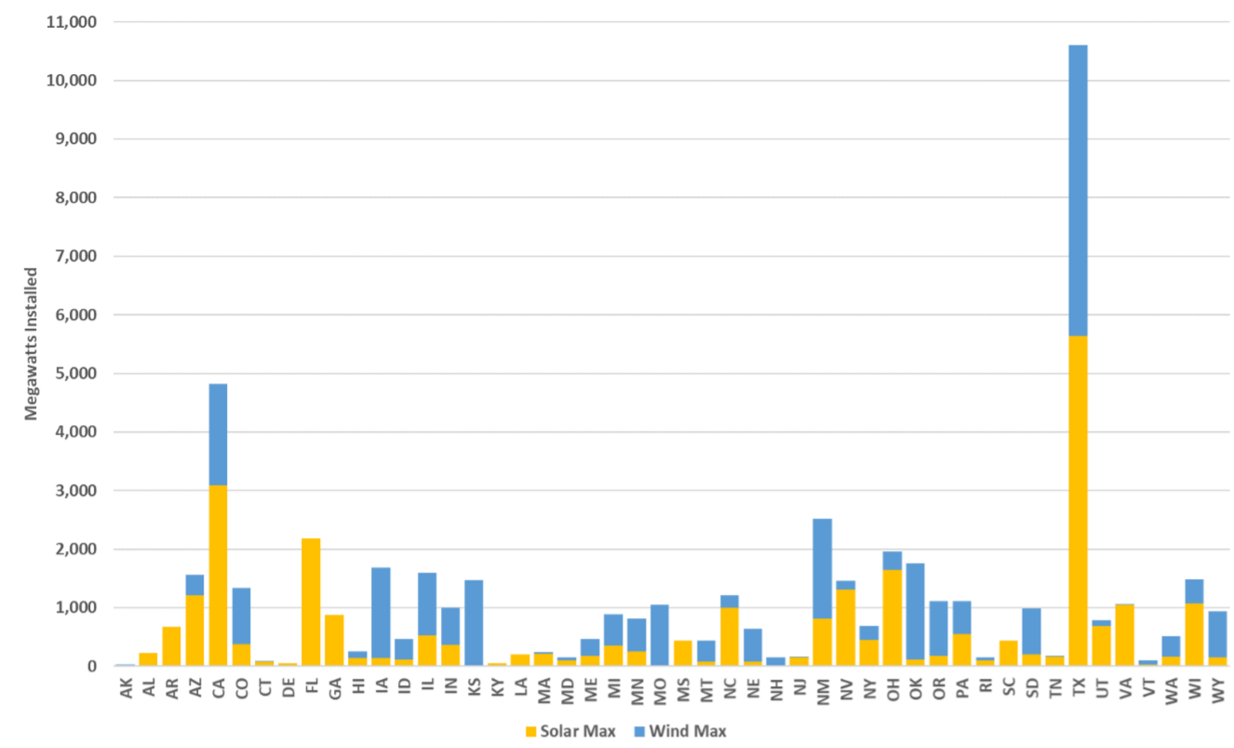
Source: Authors' calculations based on EIA (2023b), EPRI (2024), NREL (2018), Larson et al. (2021).

Ability to Install Renewables

Recent studies such as Rand et al. (2024) have attempted to quantify the status of interconnection queues and potential delays surrounding future installations of renewables. These studies suggest that far more capacity is waiting in the wings than has been able to connect to the grid in the past, implying these queues are not particularly helpful when evaluating the ability of the system to incorporate new renewables going forward. Looking back at the historical EIA data on completed installations over the last 14 years, Figure 10 shows the highest annual installations of wind and solar at a state level. Nationally since 2010, the most wind capacity that has been installed year-over-year across the country is 14.6 GW, which happened in calendar year 2021 (EIA 2023c). In the most recent available data (EIA 2024), only an additional 5.8 GW of wind were installed between June 2023 and June 2024. Conversely, the most solar that has been installed nationally over a 12-month period is 25.1 GW, which occurred between June 2023 and June 2024. In many states, these last 12 months have seen the highest levels of solar installations in history; however, wind installations in most states have declined since 2021.

While most states have at least some familiarity with connecting solar projects to the grid, only 27 states have ever added more than 200 MW of wind capacity in any given year since 2010 (200 MW is the equivalent of a single average-sized wind installation in EIA's AEO 2023 assumptions [EIA 2023c]). This combination of limited experience and potential difficulties with interconnection queues may limit the ability of states to respond to higher

Figure 10. Maximum annual renewable installations (January 2010 through June 2024)



Source: EIA (2023c, 2024).

demand growth with renewable generation. The modeling assumptions used in this analysis to test the importance of these potential constraints are detailed in the Model Structure and Data section that follows.

MODEL STRUCTURE AND DATA

This analysis is conducted with an updated version of DIEM, developed at Duke University's Nicholas Institute for Energy, Environment & Sustainability (Ross 2014). Broadly, DIEM is a dynamic linear-programming model of US wholesale electricity markets with intertemporal foresight regarding future market conditions and electricity policies. Similar to models such as EPA Integrated Planning Model (IPM) (EPA 2024b) and NREL Regional Energy Deployment System (ReEDS) (2020), it represents intermediate-to-long-run decisions about generation, transmission, capacity planning, and the dispatch or retirement of units. The model has participated in several collaborative peer-reviewed studies through the Stanford Energy Modeling Forum—see, for example, the work by Ross and Murray (2016). DIEM was also used throughout the North Carolina Clean Energy Plan stakeholder process (Konschnik et al. 2021), the EPA Clean Power Plan process to help Southern states understand the implications of alternative choices for meeting emissions goals (see, for example, Ross et al. 2016), and to examine the implications of the Inflation Reduction Act (Ross et al. 2023).

The model finds the most effective way of meeting electricity demands, reliability goals, and policy objectives at the lowest possible costs for electricity generation (including capital, fixed operating and maintenance [O&M], variable O&M, and fuel costs). The initial set of data inputs and assumptions about market trends are used by the DIEM model to estimate a baseline forecast for the industry in the absence of any new policies. This long-run baseline forecast can then be compared to model outcomes for the various policy options to see how each may affect the industry.

The broad baseline assumptions and forecasts in the model include the following (among others):

- **AEO 2023:** Initial electricity demands by region, wholesale fuel prices, costs and characteristics of non-renewable generation technologies. Demand and prices are from the Reference Case (including the IRA) forecasts in AEO 2023 (EIA 2023a).
- **NREL:** NREL Annual Technology Baseline forecasts for renewable and battery storage costs and efficiencies (NREL 2024); NREL ReEDS Standard Scenarios (2023) for characterization of operating reserves and ramp rates (spinning, regulation, flexibility [Cole et al. 2018]) and transmission networks (existing capacity and costs of expansion).
- **EPA IPM:** National Electric Energy Data System data on existing units (location, capacity, equipment, and heat rates [EPA 2024c]); IPM documentation on power sector modeling (operating costs and availability of existing units, hourly electricity demands by region, hourly wind and solar generation, availability and costs of connecting renewables to the grid, costs of retrofitting existing units with CCS, costs to transport and store carbon dioxide [EPA 2024d]).

Scenario Assumptions for Demand Growth

Analysis of policy scenarios related to the electricity industry begins by establishing a baseline forecast against which changes can be evaluated. This baseline or reference case forecast with older—and lower—demand growth forecasts is based on the standard DIEM assumptions listed above that rely on the AEO trends. For this analysis, these growth trends have been updated with more recent and higher growth forecasts. Contrasting these two trends shows the relative impacts of different growth and the sensitivities are examined across four sets of alternatives, including:

- **Electricity Demand Growth**
  - **AEO 2023:** Demand growth trends from the EIA AEO 2023. Judging by the historical EIA data for the years 2022–2024 and the starting year for these forecasts, the AEO 2023 likely does not consider much of the recent trends in electricity demand related to data centers and related technologies.
  - **IRP Growth:** These demand growth trends are based on a collection of IRP documents and other state/regional forecasts made by utilities, utility regulating bodies, and universities working with regulators. Attempting to combine these disparate sources into a cohesive forecast is not ideal given that the various

forecasts have different time horizons and provide different variables (overall electricity demand trends versus peak demand trends), but they do characterize relatively current thinking among those entities that are planning for future capacity needs (see Table A-7 for a partial list of sources). Given the differences in forecast variables, the documents are only used to provide demand growth trends for states, not absolute values for electricity demand.

- **Natural Gas Prices**
  - **~$3/MMBtu:** This forecast averages around $3/MMBtu for delivered natural gas and is based on the combination of EIA AEO 2023 wholesale (i.e., Henry Hub) prices and regional gas delivery costs from the EPA IPM model, as well as seasonal pricing from IPM.
  - **~$2/MMBtu:** This forecast averages around $2/MMBtu and is based on EPA IPM wholesale prices combined with IPM delivery costs.
- **Ability to Install Renewables**
  - **More optimistic (the standard assumption used in the modeling unless otherwise specified):** The assumption in these scenarios start by looking at the maximum annual wind and solar installations in each state since 2010 (Figure 10) and then assume that between now and 2030, each state can install twice as much new wind and solar capacity annually as the maximum achieved in the past. For states without much or any previous wind installations, it is assumed they can incorporate up to 500 MW per year of new wind into their systems (if economic). For states without solar or with low levels of solar, it is assumed they can connect 1,000 MW per year of new solar (if economic). At a national level, it is assumed that 30 GW per year of new wind can be built, permitted, and connected to the grid through 2030 (i.e., twice the highest level of installations since 2014). Nationally, up to 50 GW of new solar per year is allowed through 2030 (i.e., twice the amount seen between June 2023 and June 2024—which is the highest on record). After 2030, these constraints on the system are gradually relaxed.
  - **Less optimistic (restricted renewables):** These scenarios assume that through 2030 the most new wind capacity that can be brought online annually at a national level is equivalent to the highest historical maximum (i.e., 15 GW per year) and the most new solar capacity is similarly based on the highest historical value (i.e., 25 GW per year). The scenario also assumes that between now and 2030, each state can install only as much new wind and solar capacity annually as the maximum achieved in the past. For state without any wind installations, it is assumed they can incorporate 350 MW per year of new wind into their systems (if economic). For states without any solar, it is assumed they can connect 500 MW per year of new solar (if economic).
- **Policy Alternatives**
  - **EPA Final GHG Rule (the standard assumption):** This scenario adopts the EPA (2024a) requirements for new gas units and existing coal units. Coal units

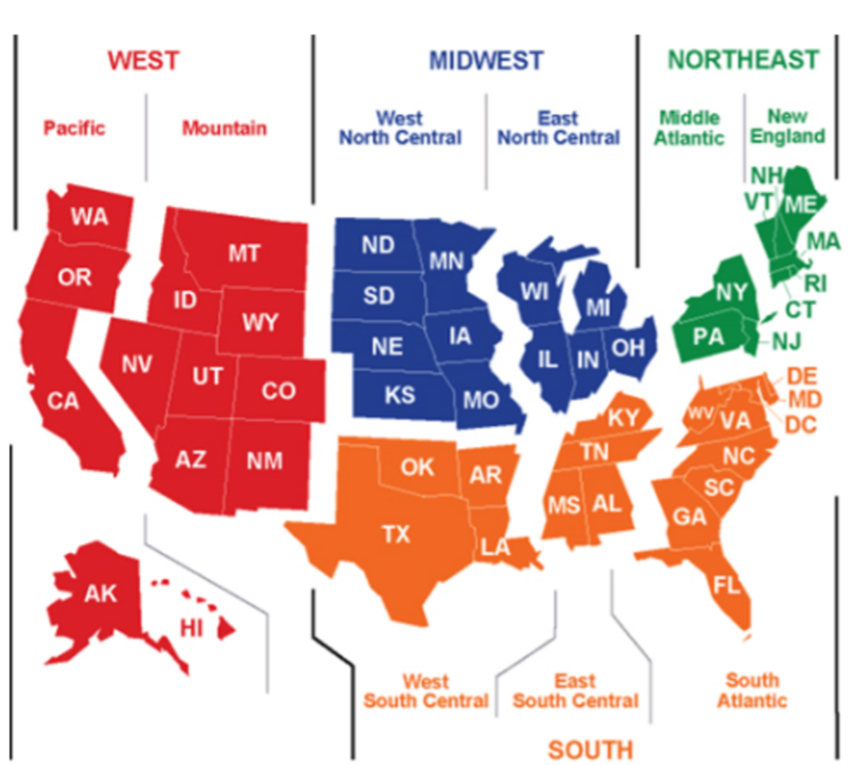
intending to operate long-term (i.e., after 2038) have to achieve an emissions rate equivalent to CCS with 90% capture by 2032, or they can choose to retire for economic reasons by 2032 (units that choose CCS retrofits are eligible for the IRA credits associated with carbon capture). In the model, a few existing coal units that expect to retire prior to 2039 must cofire with 40% natural gas to continue operating, starting in 2030 (in general, this is not chosen as an economic option in the analysis). Other coal plants retiring by 2032 have no additional obligations under the GHG rule. New baseload gas units (i.e., combined-cycle units) that wish to operate at more than a 40% utilization rate must have CCS with 90% capture by 2032. New intermediate units running between 20% to 40% of the time must operate efficiently but do not need CCS. New peaking units running less than 20% of the time do not face new requirements.

- **No 111(b):** This scenario drops the GHG rules for new natural gas units so they can operate after 2032 at rates higher than 40% without the need for CCS.
- **No 111(b)/(d):** This scenario drops all of the GHG rules for new gas and existing coal units so there are no new retirement or CCS requirements (units can still choose to add CCS to take advantage of the IRA tax credits if it is economic to do so).

Regional Aggregations

For illustrative purposes in this paper, state-level results from DIEM are aggregated into the nine EIA Census regions shown in Figure 11.

Figure 11. EIA census regions



Source: EIA (2023b.)

MODEL RESULTS

This section examines implications of the range of scenario assumptions for capacity investments, generation, utilization rates, and emissions. Policy choices and potential restrictions on renewable installations can have significant impacts on the modeling results. Depending on circumstances, these two types of factors may override the effects of natural gas prices, which would normally control the competition between natural gas and renewables when determining the preferred cost-effective method of generation using modeling.

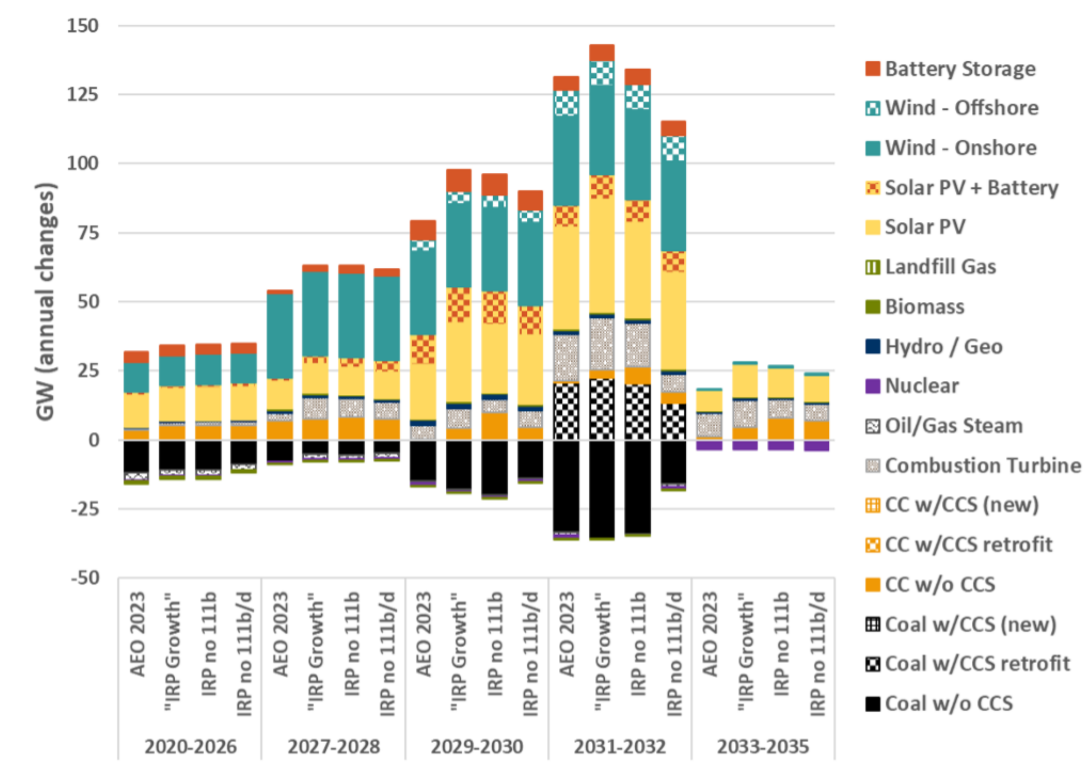
Impacts of Growth on Capacity and Generation

Figure 12 contrasts the annual capacity changes for two growth scenarios and two policy alternatives for the time periods in the DIEM model. In each set of years, the first column illustrates capacity needs under the slower AEO 2023 growth path, while the other three examine the higher IRP growth trajectory with and without elements of the EPA Final GHG Rule. Highlights in the findings include the following:

- Through 2030, coal plants are slower to retire if demand growth is higher, as illustrated by the IRP forecasts. By 2032, there are fewer differences in the coal fleet, although a few additional gigawatts of coal capacity choose to retrofit with CCS after 2032 if demand is higher.
- By 2030, higher growth leads to around 20 GW more capacity of both gas combined-cycle and combustion turbine units. Beyond 2030, the gas fleet continues to expand more rapidly under the IRP forecasts (see Tables A.2 and A.3 for details).
- Solar capacity also increases more rapidly in response to high demand. There are around an extra 25 GW of solar by 2030 and 50 GW by 2035. Wind capacity remains a cost-effective option across most all sets of scenarios and assumptions and is inclined to expand as quickly as is feasible through at least 2032.
- Eliminating the GHG rules for new gas units (no 111(b)) results in an extra 40 GW of new combined-cycle units by 2035 when modeled together with higher demand. Removing just the 111(b) component of the GHG rules related to new gas units does not affect coal plant behavior, assuming they are still covered by 111(d)-related rules for existing plants.
- Eliminating the requirement that existing coal units either retire or install CCS (depending on their age) leads to an extra 60 GW of uncontrolled coal capacity in the 2032–2035 timeframe. It also reduces the incentive for coal plants to retrofit with CCS based solely on the carbon capture subsidies in the Inflation Reduction Act.
- Fewer nuclear plants retire as a function of higher demand growth (around 3 to 4 GW by 2035). Other types of capacity are less affected by higher growth.

The first time period shown in Figure 12 (2020–2026) includes a combination of historical additions and firm-committed units, along with some additional construction determined by the model to be economic in the first model run year of 2026. However, most actions are already predetermined during past years or through ongoing construction or currently anticipated units, given that it will take some time for the system to be able to respond to

Figure 12. US annual capacity investments



Source: DIEM model.

Note: Capacity changes associated with installing a CCS retrofit on coal or gas units are shown as a negative number for the original unit (e.g., the solid black bars for coal without CCS) and a positive number for the same unit with a CCS retrofit (e.g., the coal category shown with black and white squares). CCS units online by 2032 are shown as installations occurring in the 2031–2032 time period in the model.

anticipated growth. If this anticipated growth, as illustrated by the IRP Growth forecast, is higher than was previously suggested in the AEO 2023 forecast, there is additional expansion in both solar and combined-cycle capacity.

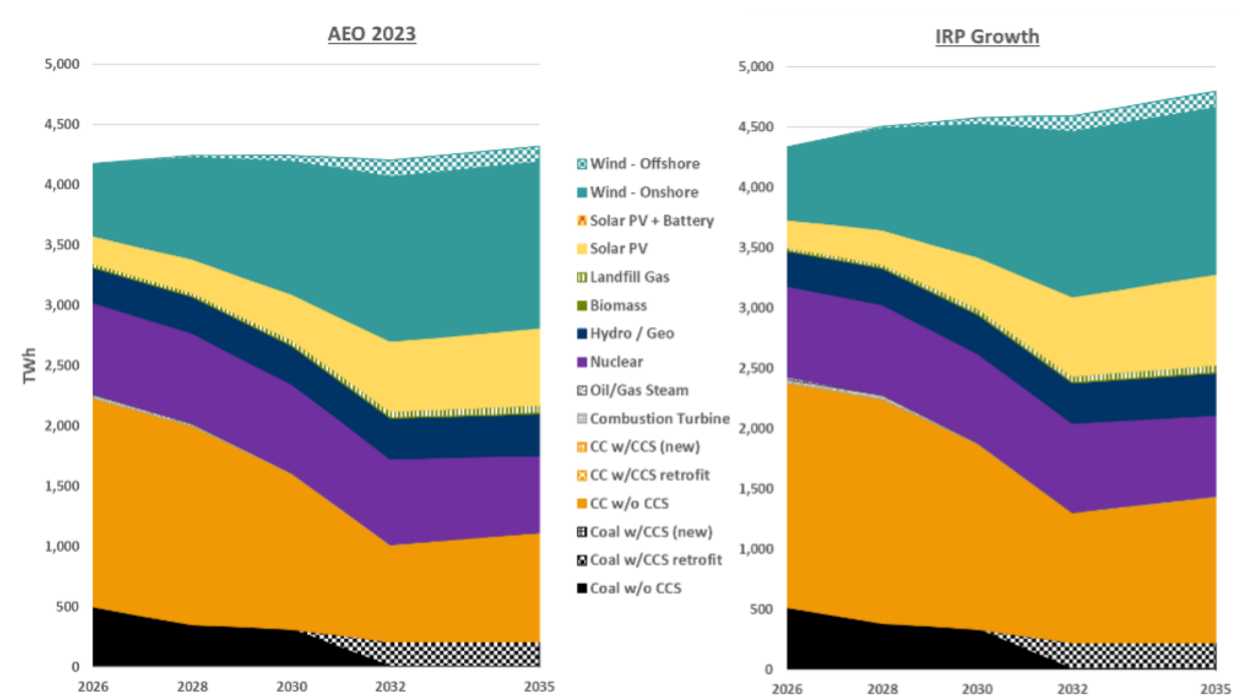
The next few years (beginning with 2027–2028) see wind capacity begin attempting to maximize installations to take advantage of the IRA tax credits (presumably chosen as a production tax credit for wind, unlike solar and other types of capacity that lean toward investment tax credits). Beyond the wind units, additional solar and storage also expands in response to the higher growth in the IRP forecasts. Most of the additional gas units are in the form of combustion turbines, although there are a few more combined-cycle units and a few less coal retirements. Through 2028, any repeal of the GHG rules has little effect on capacity decisions since most of the rule's provisions begin affecting coal plants starting in 2030.

During the 2029–2030 time frame, the higher-demand growth in the IRP forecasts begins to separate its capacity needs from those in the AEO 2023 forecast. Coal plants that would have retired by 2028 in the AEO forecast may now have to retire (or be willing to retrofit with CCS by 2032) under the EPA Final GHG Rules. More combined-cycle units and solar installations are used to meet the higher needs of the IRP-related scenarios. If new combined-cycle units were not subject to these GHG rules (IRP no 111[b]) there would be significant additional investment in these gas plants, offset by a few more coal plant retirements. If neither coal nor gas units are subject to the GHG rules, the balance shifts toward continued operation of existing coal plants, rather than some of the extra construction of new combined-cycle plants. Operating these existing fossil units at higher utilization rates also means that overall new capacity needs are reduced, particularly shifting the balance away from new solar.

In the years after 2030, the higher demand in the IRP forecasts delays some of the early retirement of nuclear plants (IRA credits for nuclear generation expire by 2033). Beyond these changes, the higher demand growth tends to favor new combined-cycle units, regardless of any potential exemptions of units from the GHG rules. This trend toward meeting higher demand with new combined-cycle units continues after 2032 as well.

Generation follows capacity but, given the different utilization rates of fossil and nuclear generation compared to renewables, it can still be illustrative to briefly examine overall generation patterns associated with the capacity additions and retirements discussed previously. Figure 13 contrasts the generation requirement to meet AEO 2023 demand trends

Figure 13. US total generation: AEO 2023 demand versus IRP demand



Source: DIEM model.

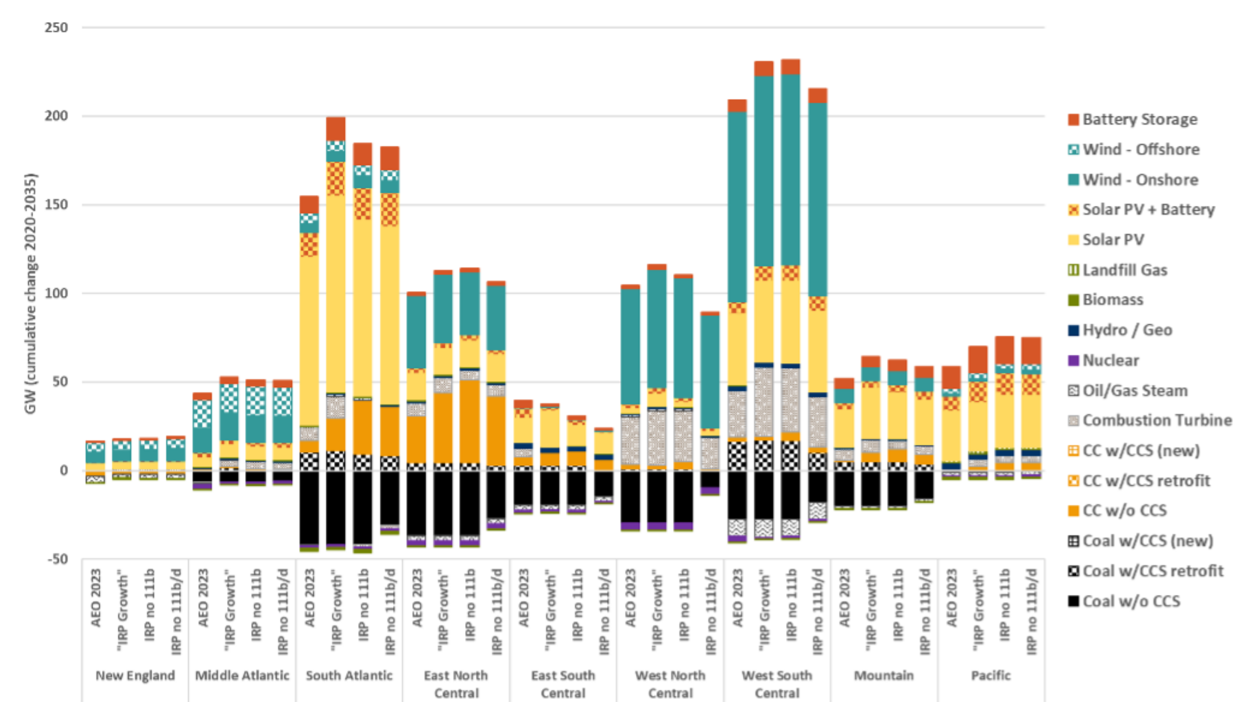
Note: The slight dip in 2032 is a function of the regional distribution of demand, how state forecasts vary by year and time horizon, and the curtailment of renewables in different years.

with those from the main IRP forecast at a national level through 2050. Highlights of the findings include the following:

- Total generation is up more than 10% by 2035 as the system attempts to meet the demand seen in the IRP forecasts, compared to the older AEO 2023 levels.
- The largest increase in generation in response to the higher IRP demands is from combined-cycle units, which increase output by around 20% in 2030 and 30% by 2035.
- Coal generation is initially higher, but once the GHG rules take full effect in 2032 (assuming no parts of these rules are repealed), coal generation is largely unaffected by higher demand, since once coal units add CCS retrofits they tend to run at their maximum utilization rates.
- Solar generation increases by around 15% as the result of the higher IRP demand.

How new renewables—and other new capacity—are distributed across regions can vary significantly, depending on the types and costs of resources available in different states. Figure 14 looks at cumulative investments and retirements that occur between 2020 and 2035 across nine regions of the country and compares the AEO 2023 growth trends to several scenario variations based on the IRP forecasts (see Table A.6 for additional detail on these changes). Note that these regional findings already include preexisting state policies, based on EPA documents (2024b). Highlights of the findings include:

Figure 14. Regional cumulative capacity investments (2020–2035)



Source: DIEM model.

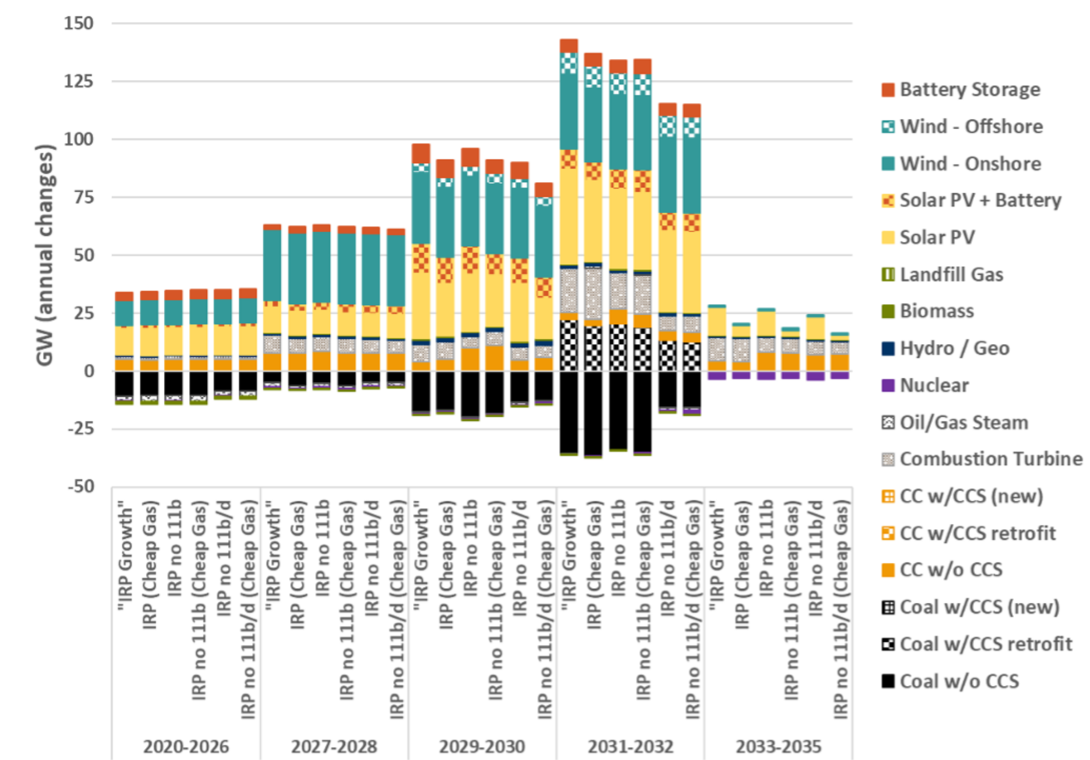
- The upper East Coast regions of New England and the Middle Atlantic experience comparatively lower overall impacts from the IRP forecasts, although there are somewhat fewer coal and nuclear retirements than seen under the AEO 2023 demand forecast.
- The South Atlantic region, which includes states such as Virginia and Georgia that anticipate high growth from data centers, has the largest increase in total capacity between the AEO 2023 and IRP forecasts. Much of the expansion to meet higher demand is from combined-cycle units. If new combined-cycle units are not covered by the GHG rules (IRP no 111[b]), their capacity expands even more. Fewer combustion turbines are needed when there are additional baseload combined-cycle units, and also fewer coal units retire if they are also not covered by the GHG rules (IRP no 111[b]/[d]).
- A similar pattern is seen in the East North Central region, where the total capacity of combined-cycle units increases under higher demand. Total capacity changes in the East South Central region are reduced, but the mix shifts toward new combined-cycle and—in the "IRP no 111(b)/(d)" case—away from coal retirements.
- In the West North Central region, additional solar is used to address the higher growth in the IRP scenario (if it were feasible to continue expanding wind generation, this option might take precedence over solar). If coal plants are not covered by the GHG rules, this shifts back toward fewer coal retirements.
- The West South Central region is inclined to meet higher demand through additional solar installations and fewer nuclear retirements (assuming coal plants remain covered by the GHG rules).
- Higher electricity demand in the Mountain and Pacific regions is largely supplied through additional combined-cycle units.

Typically, low-priced natural gas tends to crowd out renewables (and, in some cases, nuclear). However, if both renewables and new combined-cycle units are experiencing difficulties with interconnection queues, this competition is less likely to be a determining factor in the analysis as fewer gigawatts of gas capacity are needed to offset more gigawatts of renewables.3 Figure 15 compares the higher "IRP Growth" forecast, which is based on delivered gas prices that average around $3/MMBtu, with an "IRP (Cheap Gas)" scenario that uses wholesale gas prices from the EPA IPM model that suggests delivered prices around $2/MMBtu. Contrasting the first two columns of each set of annual capacity additions by year suggests that, in many years, lower gas prices have relatively limited impacts. This situation could potentially be altered if natural gas units were excluded from the EPA GHG rules in some fashion. Overall, highlights of the national findings include:

- Through 2028, the availability of lower-priced gas has little effect on investments and retirements, regardless of any repeal of parts or all of the GHG rules.

3 Although not included in the model decision process, there may also be potential benefits related to siting combined-cycle units at locations where older fossil plants have retired. See, for example, the article by the American Public Power Association - https://www.publicpower.org/periodical/article/utilities-look-develop-gas-plant-projects-coal-plant-sites.

Figure 15. Effects of natural gas prices on annual capacity investments



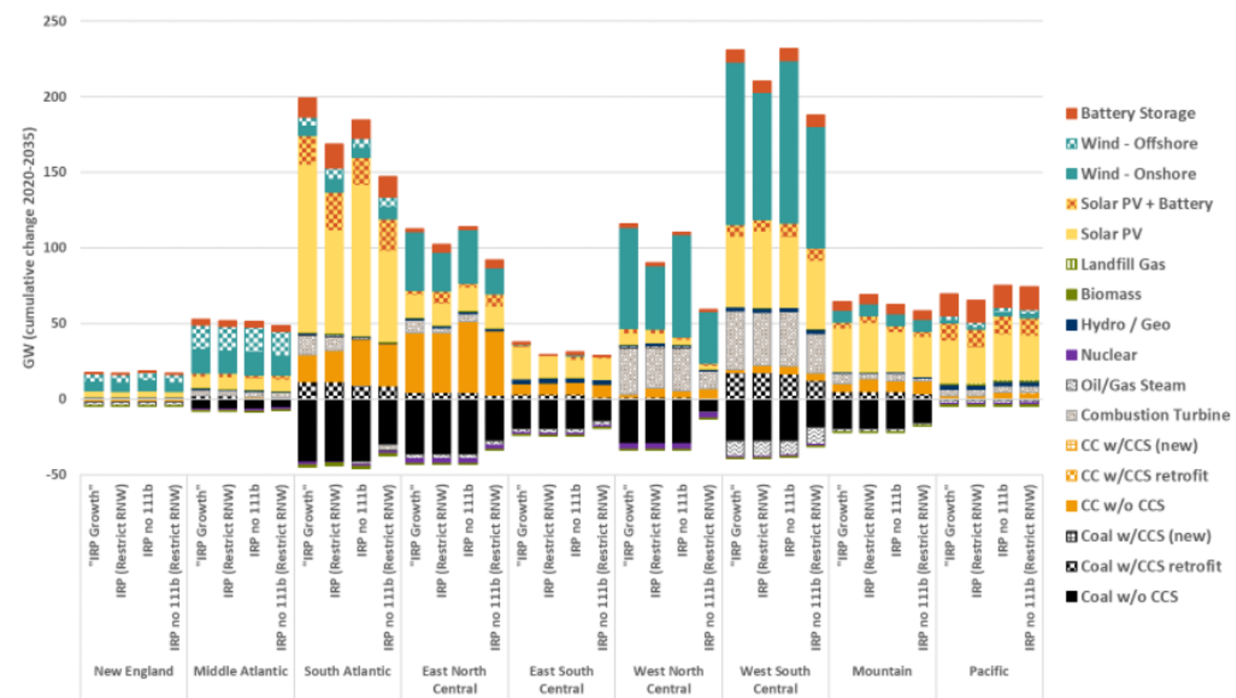
Source: DIEM model.

- By 2030, there is some shifting toward gas generation and away from renewables if natural gas is cheap (IRP Growth versus IRP [Cheap Gas]), however, the shift is not particularly dramatic. Any potential repeal of parts of the GHG rules has more impact on gas capacity than does the price of gas itself.
- Similar effects hold through 2032, the last year to take advantage of the IRA tax credits for renewables. Removing GHG rules for existing coal plants has a much larger impact on capacity investment needs than the price of natural gas.

Figure 16 looks at how limitations on the ability of the grid to incorporate renewables may impact different regions of the country—"IRP (Restrict RNW)"—assuming that overall electricity demand growth is comparatively high as represented by the IRP forecasts. The results also show how a potential repeal of the requirements for new combined-cycle units to either install CCS or run below 40% utilization (IRP no 111[b]) might alter competition between gas and renewable generation. The graph presents cumulative impacts of the higher demand growth on capacity and retirements between 2020 and 2035. The findings indicate the following:

- More restrictive limitations on renewable installations can have comparatively large effects on capacity choices in some regions of the country, particularly in those areas with higher-than-average demand growth and the potential availability of renewable resources.

Figure 16. Cumulative effects of additional limits on renewables at a regional level (2035)



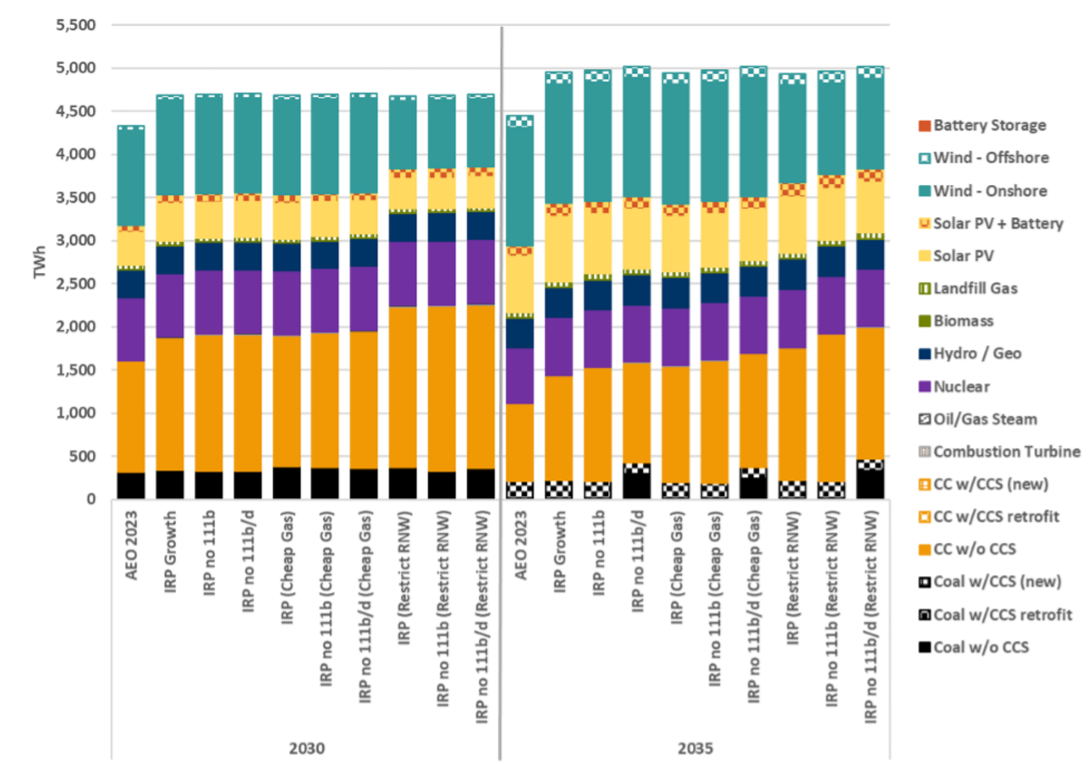
Source: DIEM model.

- The South Atlantic and West South Central regions have a tendency to move from renewables into gas combined-cycle capacity. Other regions show the same pattern, but the absolute differences in capacity between the main IRP forecast and the IRP findings with more restricted renewables are less dramatic.
- If new natural gas units are not covered by the GHG rules, this shift out of renewables and into natural gas is more pronounced. At a regional level, these shifts related to renewable availability are larger than those seen based on the availability of lower-priced natural gas.

Figure 17 looks at national generation in 2030 and 2035 across the scenarios shown in the previous three graphs. Highlights of the findings include the following:

- Total generation is higher in 2030 under any of the IRP variants to accommodate the additional demand growth. In most scenarios, the generation mix has not changed much by 2030, aside from the combined-cycle units, unless fewer renewables are allowed onto the grid and require even more gas generation to offset declines in wind generation.
- By 2035, total demand is significantly higher in the IRP growth forecast than seen under the older AEO 2023 trends. Generation by renewables is not impacted to a large degree under either the main IRP forecast or the alternative IRP scenarios with lower-priced natural gas.

Figure 17. US generation across policy, gas price, and renewables assumptions



Source: DIEM model.

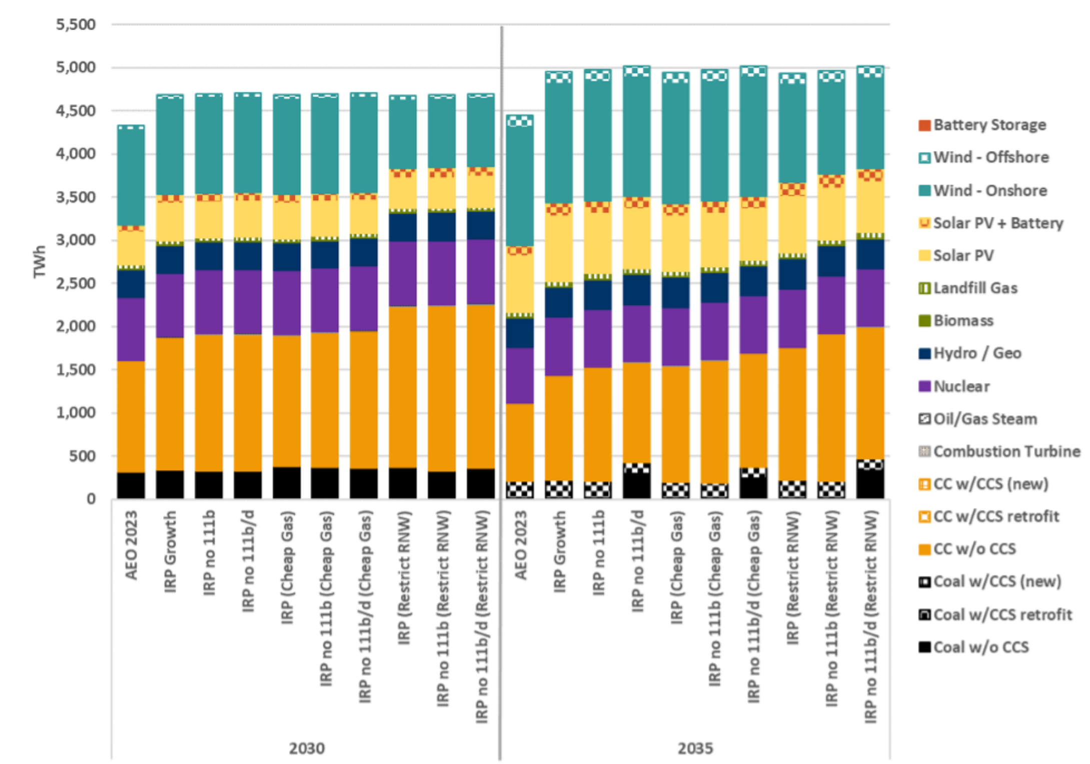
Note: The slight variations in the IRP generation levels are mainly a function of any curtailment of renewables.

- By 2035, lower-priced gas leads to some additional combined-cycle generation across all scenarios, but for this effect to be particularly pronounced, fewer renewables have to be allowed into the system. Repealing the 111(b) parts of the GHG rules leads to increased gas generation. However, removing 111(d) requirements for existing coal units lowers overall gas generation, lowers generation from coal units with CCS retrofits, and allows generation from non-CCS coal units that operate for longer than allowed under the EPA Final GHG Rule.

Figure 18 looks at how utilization rates respond to the alternative scenarios in Figure 17. Utilization rates by existing versus new fossil units can show why generation and overall emissions may vary across alternative futures. Requirements in the Final GHG Rules regarding the utilization rates of new combined-cycle units—which are limited to 40% if they don't add CCS—can affect the behavior of these plants significantly (limitations in the GHG rules on intermediate load and peaking gas units do not affect the model results much, if at all). Highlights of the utilization findings include the following:

- Coal units average around 30% utilization rates unless there are shifts in either GHG policies or natural gas prices. If coal is not covered by Section 111(d), the utilization

Figure 18. Utilization rates for fossil units in 2035



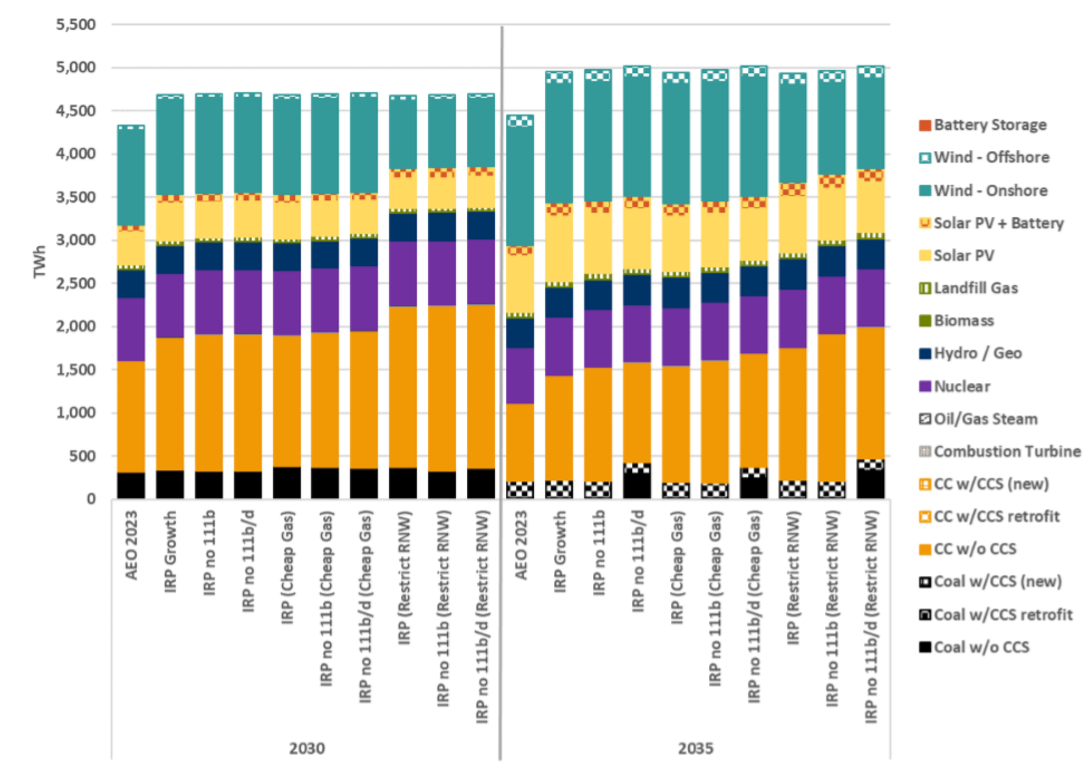
Source: DIEM model.

Note: Units that either retrofit or are built with CCS run at the maximum feasible rate.

rates almost double in the presence of higher demand growth. This impact is reduced if natural gas is cheap, because the coal units aren't needed as much. Restricting renewables access to the grid while repealing the parts of the GHG rule related to coal units results in an even higher utilization rate for coal.

- In the absence of any changes in the GHG rules related to new gas units, the existing combined-cycle units respond to higher demand growth by increasing their utilization rates from around 30% in the AEO 2023 scenario to closer to 40% under the IRP scenario. Cheaper natural gas or limits on renewables enhances this effect, leading to utilization rates around 45% to 50%. Conversely, if new gas units are exempted from the GHG rules for any reason, the utilization rates of existing gas units tend to decline as generation shifts toward the additional new combined-cycle units that are constructed under these policy options.
- New combined-cycle units without CCS, by far the largest share of new combined-cycle capacity, are limited to a 40% utilization rate under the GHG rules. If that requirement were repealed, new gas units would run essentially at their maximum feasible rates (around 87%).

Figure 19. US CO_2 emissions trends across scenarios



Source: DIEM model.

Figure 19 builds on Figure 5 and contrasts emissions from the main growth scenarios to alternative gas price, renewables availability, and policy futures. Highlights of these emissions results include the following:

- Based on the older AEO 2023 forecast of demand growth, emissions can fall below 400 $MMTCO_2$, the level at which IRA subsidies can expire. However, this is not the case for any of the scenarios that consider the higher demand growth in the IRP forecasts.
- Emissions are 30% to 35% higher after 2032 under the higher-growth scenarios, regardless of the GHG rules.
- The availability of lower-priced gas has less of an impact on emissions than might have been seen in past analyses because the GHG rules disincentivize new gas by requiring either CCS or, as seen in Figure 18, that utilization rates fall below 40%. However, removing the 111(b) rules for new combined-cycle units does not have a dramatic impact on emissions as some of the generation shifts from older, less-efficient gas units to the additional new gas units that would be installed without the 111(b) rules.
- Restricting the ability of renewables to enter the system has a much larger effect on emissions than alterations to requirements for new gas units.
- The largest increase in emissions occurs if existing coal plants are not subject to the GHG rules under Section 111(d). This effect is amplified even further if renewables are restricted.

NEXT STEPS

There remain a wide range of additional issues regarding demand growth and renewables availability that can be investigated in more detail. Among these considerations are the following:

1. There may be short-term stresses on the system over the next few years. The current modeling combines longer-term capacity planning with hourly evaluations of how the system is able to respond in a particular year. However, additional investigation of potential shortfalls in the near term, or potential inability to add all of the desired demand centers in some regions, would be a useful extension of the current analysis. Typically, models take demand as a given quantity, but in the real world, concerns about the availability and reliability of electricity supplies can have feedback effects on the locations of new demand.
2. Many companies interested in expanding their cloud computing and AI capabilities are also interested in meeting internal goals for clean energy and emissions reductions. Tying these new electricity demand sources to specific types of generation might lead to different conclusions in the analysis, although this is not guaranteed in a setting where renewables are already expanding and not all such generation is tied to specific use cases.
3. Based on the model's current assumptions regarding the capital costs of new types of generation, such as small modular reactors or combined-cycle units with CCS, the analysis does not suggest that these types of units are likely to play much of a role in providing for higher electricity demand. Further evaluation of how changes in these units' costs might influence their adoption would be helpful, particularly in the context of additional climate policies.
4. Other sensitivities would also be useful for understanding how the system may respond to future conditions. A wider range of demand growth estimates can be examined, along with other scenarios such as renewables availability and costs, fuel prices, and broader economy-wide climate goals. These types of stresses on the system can be particularly informative at the regional and state levels, where many of these decisions are being made.

REFERENCES

Cole, W., K. Eurek, N. Vincent, T. Mai, M. Mowers, and G. Brinkman. 2018. Operating Reserves in Long-Term Planning Models. Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy18osti/71148.pdf.

EIA. 2023a. Annual Energy Outlook 2023. Washington, DC: Energy Information Administration. https://www.eia.gov/outlooks/aeo/.

EIA. 2023b. "Assumptions to the Annual Energy Outlook 2023." Washington, DC: Energy Information Administration. https://www.eia.gov/outlooks/aeo/assumptions/.

EIA. 2023c. Electric Power Annual 2023. Washington, DC: Energy Information Administration. https://www.eia.gov/electricity/annual/.

EIA. 2024. "Electric Power Monthly June 2024." Washington, DC: Energy Information Administration. https://www.eia.gov/electricity/monthly/.

EPA. 2024a. "Analysis of the Final Greenhouse Gas Standards and Guidelines." Washington, DC: US Environmental Protection Agency. https://www.epa.gov/power-sector-modeling/analysis-final-greenhouse-gas-standards-and-guidelines.

EPA. 2024b. "Documentation for 2023 Reference Case." Washington, DC: US Environmental Protection Agency. https://www.epa.gov/power-sector-modeling/documentation-2023-reference-case.

EPA. 2024c. "National Electric Energy Data System (NEEDS): rev 06-06-2024." Washington, DC: US Environmental Protection Agency. https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs.

EPA. 2024d. "Results Using 2023 Reference Case." Washington, DC: US Environmental Protection Agency. https://www.epa.gov/power-sector-modeling/results-using-2023-reference-case.

EPRI. 2024. Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption. Report #3002028905. Palo Alto, CA: EPRI. https://www.epri.com/research/products/000000003002028905.

Ewing, J., M. Ross, A. Pickle, R. Stout, and B. Murray. 2022. Pathways to Net-Zero for the US Energy Transition. NI R 22-01. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University. https://nicholasinstitute.duke.edu/publications/pathways-net-zero-us-energy-transition.

ICF. 2024. "How utilities can manage surging electricity demand". https://www.icf.com/insights/energy/demand-growth-challenges-opportunities-utilities.

Konschnik, K., M. Ross, J. Monast, J. Weiss, and G. Wilson. 2021. Power Sector Carbon Reduction: An Evaluation of Policies for North Carolina. NI R 21-01. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University. https://nicholasinstitute.duke.edu/publications/power-sector-carbon-reduction-evaluation-policies-north-carolina.

Larson, E., C. Greig, J. Jenkins, E. Mayfield, A. Pascale, C. Zhang, J. Drossman, R. Williams, S. Pacala, R. Socolow, EJ Baik, R. Birdsey, R. Duke, R. Jones, B. Haley, E. Leslie, K. Paustian, and A. Swan. 2021. Net-Zero America: Potential Pathways, Infrastructure, and Impacts: Final Report. Princeton, NJ: Princeton University. https://netzeroamerica.princeton.edu/the-report.

Murray, B., W. Pizer and M. T. Ross. 2015. “Regulating Existing Power Plants under the U.S. Clean Air Act: Present and Future Consequences of Key Design Choices.” Energy Policy 83: 87–98. https://doi.org/10.1016/j.enpol.2015.03.028.

Mai, T., P. Jadun, J. Logan, C. McMillan, M. Muratori, D. Steinberg, L. Vimmerstedt, R. Jones, B. Haley, and B. Nelson. 2018. *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71500. https://www.nrel.gov/docs/fy18osti/71500.pdf.

NREL. 2020. “Regional Energy Deployment System (ReEDS) Model Documentation: Version 2020.” Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/analysis/reeds/.

NREL. 2023. “2023 Standard Scenarios Report.” Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/analysis/standard-scenarios.html.

NREL. 2024. “2024 Electricity ATB Technologies and Data Overview.” Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/electricity/2024/index.

OnLocation. 2024. Data Center Demands & Impacts on the Energy System: An Energy Horizons Special Report. https://onlocationinc.com/whitepapers/data-center-demands-impacts-on-the-energy-system-an-energy-horizons-special-report/.

Rand, J., N. Manderlink, W. Gorman, R. Wiser, J. Seel, J. M. Kemp, Se. Jeong, and F. Kahrl. 2024. Queued Up: 2024 Edition. Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2023. Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf.

Ross, M. T. 2014. Structure of the Dynamic Integrated Economy/Energy/Emissions Model: Electricity Component, DIEM-Electricity. NI WP 14-11. Durham, NC: Duke University. http://nicholasinstitute.duke.edu/environment/publications/structure-dynamic-integrated- economyenergyemissions-model-electricity-component-diem.

Ross, M. T. 2018. “The Future of the Electricity Industry: Implications of Trends and Taxes.” Energy Economics 73: 393–409. doi:10.1016/j.eneco.2018.03.022.

Ross, M. T. 2019. Emissions Benefits of Electric Vehicles: Influencing Electricity Generation Choices. 2019. NI WP 19-04. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University. https://nicholasinstitute.duke.edu/publications/emissions-benefits-electric-vehicles-influencing-electricity-generation-choices.

Ross, M. T., and B. C. Murray. 2016. “What Is the Fuel of the Future? Prospects under the Clean Power Plan.” Energy Economics 60: 451–9. doi:10.1016/j.eneco.2016.09.021.

Ross, M. T., D. Hoppock, and B. Murray. 2016. Ongoing Evolution of the Electricity Industry: Effects of Market Conditions and the Clean Power Plan on States. NI WP 16-07. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University. https://nicholasinstitute.duke.edu/content/ongoing-evolution-electricity-industry- effects-market-conditions-and-clean-power-plan.

Ross, M. T., J. Ewing, B. Murray, T. Profeta, and R. Stout. 2023. "Projecting Electricity-Sector Investments Under the Inflation Reduction Act: New Cost Assumptions and Interactions with EPA's Greenhouse Gas Proposal." Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University. https://nicholasinstitute.duke.edu/publications/projecting-electricity-sector-investments-under-inflation-reduction-act.

Wilson, J. D., and Z. Zimmerman. 2023. The Era of Flat Power Demand is Over. Bethesda, MD: Grid Strategies. https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

APPENDIX: DATA TABLES

Table A.1. Maximum Compared to Most Recent Annual Installations (2010–2024 Versus June 2023–June 2024)

State	Solar		Wind	
	01/10–06/24	06/23–06/24	01/10–06/24	06/23–06/24
Alaska	6.9	27.3	6.9	0.0
Alabama	277.0	—	—	—
Arizona	1,214.8	350.0	1,214.8	216.0
Arkansas	671.4	—	671.4	—
California	3,086.7	1,734.2	3,086.7	267.3
Colorado	377.5	958.7	297.2	199.0
Connecticut	84.5	4.0	32.1	0.0
Delaware	51.5	0.0	7.4	0.0
District of Columbia	9.5	—	9.5	—
Florida	2,180.0	—	2,180.0	—
Georgia	871.5	—	515.1	—
Hawaii	143.6	114.0	71.6	0.0
Idaho	120.0	351.4	100.0	160.0
Illinois	527.4	1,069.6	364.4	378.8
Indiana	372.4	630.6	372.4	87.0
Iowa	142.5	1,538.5	62.3	200.9
Kansas	20.0	1,447.3	3.0	804.6
Kentucky	58.8	—	58.8	—
Louisiana	200.0	—	200.0	—
Maine	173.7	286.0	173.7	0.0
Maryland	108.0	50.0	66.6	0.0
Massachusetts	214.7	30.0	48.6	0.0
Michigan	354.4	533.5	267.3	214.2
Minnesota	249.9	564.0	137.2	0.0
Mississippi	434.8	—	434.8	—
Missouri	22.9	1,027.9	0.0	0.0
Montana	80.0	366.2	80.0	310.7
Nebraska	81.0	562.7	81.0	0.0

Table A.1. Maximum Compared to Most Recent Annual Installations (2010–2024 Versus June 2023–June 2024)

State	Solar		Wind	
	01/10–06/24	06/23–06/24	01/10–06/24	06/23–06/24
Nevada	1,314.9	150.0	1,314.9	0.0
New Hampshire	2.4	14.7	0.0	0.0
New Jersey	153.8	0.1	47.8	0.0
New Mexico	816.2	1,708.0	816.2	0.0
New York	450.3	234.1	437.0	219.3
North Carolina	1,000.2	208.0	467.5	0.0
North Dakota	—	—	—	—
Ohio	1,653.2	302.0	1,653.2	4.5
Oklahoma	120.0	1,642.7	120.0	502.5
Oregon	173.7	943.9	63.7	0.0
Pennsylvania	552.3	554.6	552.3	92.6
Rhode Island	109.0	42.8	109.0	0.0
South Carolina	440.8	—	81.9	—
South Dakota	208.0	783.7	208.0	397.4
Tennessee	170.7	0.1	139.0	0.0
Texas	5,635.0	4,973.6	5,635.0	1,419.8
Utah	689.4	102.4	565.1	0.0
Vermont	33.3	75.0	7.0	0.0
Virginia	1,048.5	12.0	1,048.5	0.0
Washington	165.0	352.7	0.0	0.0
West Virginia	—	—	—	—
Wisconsin	1,075.0	404.7	1,075.0	0.0
Wyoming	150.0	793.0	150.0	99.1

Source: EIA (2023c, 2024).

Table A.2. Total US Capacity Across Scenarios (GW)—Elected Types

Year	Electricity Demand Growth	Delivered Natural Gas Prices	EPA GHG Rules	Existing Coal w/o CCS	Existing Coal w/ retrofit CCS	Combined Cycle	Combustion Turbine	Nuclear	Solar PV	Solar PV + Battery	Onshore Wind	Battery Storage
2030	AEO 2023	~$3/MMBtu	Final Rule	67	—	312	169	91	174	33	304	38
			No 111(b)	64	—	318	167	91	165	33	304	38
			No 111(b)/(d)	93	—	306	168	92	168	31	304	36
		~$2/MMBtu	Final Rule	72	—	314	170	92	149	26	304	34
			No 111(b)	65	—	324	168	91	149	28	304	34
			No 111(b)/(d)	89	—	315	168	91	149	27	304	34
	IRP Growth	~$3/MMBtu	Final Rule	72	—	331	187	92	193	41	304	42
			No 111(b)	68	—	342	180	92	186	41	304	42
			No 111(b)/(d)	93	—	330	182	92	187	40	304	42
		~$2/MMBtu	Final Rule	74	—	332	184	93	182	40	304	43
			No 111(b)	71	—	343	181	92	181	38	304	41
			No 111(b)/(d)	96	—	332	179	93	174	38	304	41
	IRP with Reduced Renew-ables	~$3/MMBtu	Final Rule	76	—	341	174	93	161	46	229	45
			No 111(b)	71	—	348	173	93	161	48	229	46
			No 111(b)/(d)	96	—	340	170	93	160	49	229	47
		~$2/MMBtu	Final Rule	84	—	334	173	93	166	45	229	46
			No 111(b)	81	—	343	172	93	167	43	229	44
			No 111(b)/(d)	100	—	334	173	93	163	47	229	46

Table A.2. Total US Capacity Across Scenarios (GW)—Elected Types

Year	Electricity Demand Growth	Delivered Natural Gas Prices	EPA GHG Rules	Existing Coal w/o CCS	Existing Coal w/ retrofit CCS	Combined Cycle	Combustion Turbine	Nuclear	Solar PV	Solar PV + Battery	Onshore Wind	Battery Storage
2035	AEO 2023	~$3/MMBtu	Final Rule	0	42	318	228	79	269	49	368	47
			No 111(b)	0	39	338	210	79	254	49	368	47
			No 111(b)/(d)	59	27	321	187	79	254	48	368	46
		~$2/MMBtu	Final Rule	0	35	319	232	78	210	48	368	47
			No 111(b)	0	32	347	211	74	211	49	368	47
			No 111(b)/(d)	59	18	332	188	71	211	48	368	47
	IRP Growth	~$3/MMBtu	Final Rule	0	45	351	255	82	310	59	370	53
			No 111(b)	0	41	379	232	82	285	58	370	53
			No 111(b)/(d)	59	27	359	212	82	284	56	370	52
		~$2/MMBtu	Final Rule	0	39	350	258	83	265	57	370	53
			No 111(b)	0	38	379	234	82	253	58	370	53
			No 111(b)/(d)	64	25	362	209	81	248	55	370	51
	IRP with Reduced Renew-ables	~$3/MMBtu	Final Rule	0	45	365	235	83	263	67	310	58
			No 111(b)	0	41	398	211	82	245	66	292	57
			No 111(b)/(d)	60	30	376	195	82	243	64	288	56
		~$2/MMBtu	Final Rule	0	47	362	236	83	262	65	310	58
			No 111(b)	0	44	387	219	83	244	65	298	57
			No 111(b)/(d)	63	28	370	199	82	241	63	293	56

Source: DIEM model.

Table A.3. Incremental US Capacity Compared to AEO 2023 Scenario Estimates (GW)—Selected Types

Year	Electricity Demand Growth	Delivered Natural Gas Prices	EPA GHG Rules	Existing Coal w/o CCS	Existing Coal w/ retrofit CCS	Combined Cycle	Combustion Turbine	Nuclear	Solar PV	Solar PV + Battery	Onshore Wind	Battery Storage
2030	AEO 2023	~$3/MMBtu	Final Rule	—	—	—	—	—	—	—	—	—
			No 111(b)	—	—	—	—	—	—	—	—	—
			No 111(b)/(d)	—	—	—	—	—	—	—	—	—
		~$2/MMBtu	Final Rule	—	—	—	—	—	—	—	—	—
			No 111(b)	—	—	—	—	—	—	—	—	—
			No 111(b)/(d)	—	—	—	—	—	—	—	—	—
	IRP Growth	~$3/MMBtu	Final Rule	5	—	19	18	1	19	8	0	5
			No 111(b)	4	—	24	13	1	20	8	0	5
			No 111(b)/(d)	1	—	24	14	0	19	8	0	5
		~$2/MMBtu	Final Rule	1	—	18	14	1	33	14	0	8
			No 111(b)	5	—	19	12	2	32	10	0	7
			No 111(b)/(d)	7	—	17	10	2	25	10	0	7
	IRP with Reduced Renewables	~$3/MMBtu	Final Rule	10	—	29	5	2	-13	13	–75	8
			No 111(b)	6	—	30	6	2	-5	14	–75	9
			No 111(b)/(d)	3	—	33	2	1	-8	18	–75	11
		~$2/MMBtu	Final Rule	12	—	20	2	2	18	18	–75	11
			No 111(b)	16	—	19	3	2	18	16	–75	10
			No 111(b)/(d)	11	—	19	4	2	15	20	–75	12

Table A.3. Incremental US Capacity Compared to AEO 2023 Scenario Estimates (GW)—Selected Types

Year	Electricity Demand Growth	Delivered Natural Gas Prices	EPA GHG Rules	Existing Coal w/o CCS	Existing Coal w/ retrofit CCS	Combined Cycle	Combustion Turbine	Nuclear	Solar PV	Solar PV + Battery	Onshore Wind	Battery Storage
2035	AEO 2023	~$3/MMBtu	Final Rule	—	—	—	—	—	—	—	—	—
			No 111(b)	—	—	—	—	—	—	—	—	—
			No 111(b)/(d)	—	—	—	—	—	—	—	—	—
		~$2/MMBtu	Final Rule	—	—	—	—	—	—	—	—	—
			No 111(b)	—	—	—	—	—	—	—	—	—
			No 111(b)/(d)	—	—	—	—	—	—	—	—	—
	IRP Growth	~$3/MMBtu	Final Rule	0	3	33	27	4	40	10	2	6
			No 111(b)	0	2	40	22	3	31	9	2	6
			No 111(b)/(d)	0	0	38	26	3	30	9	2	5
		~$2/MMBtu	Final Rule	0	4	32	27	6	54	9	2	6
			No 111(b)	0	6	32	22	8	42	9	2	6
			No 111(b)/(d)	4	7	30	20	10	36	7	2	5
	IRP with Reduced Renewables	~$3/MMBtu	Final Rule	0	3	47	7	5	–6	18	–58	11
			No 111(b)	0	2	59	1	4	–8	17	–76	10
			No 111(b)/(d)	1	3	55	8	4	–11	16	–80	10
		~$2/MMBtu	Final Rule	0	12	44	4	6	52	17	–58	11
			No 111(b)	0	12	40	7	9	33	16	–70	10
			No 111(b)/(d)	4	10	38	10	11	30	15	–75	9

Source: DIEM model.

Table A.4. Total US Generation Across Scenarios (TWh)—Selected Types

Year	Electricity Demand Growth	Delivered Natural Gas Prices	EPA GHG Rules	Existing Coal w/o CCS	Existing Coal w/ retrofit CCS	Combined Cycle	Combustion Turbine	Nuclear	Solar PV	Solar PV + Battery	Onshore Wind	Battery Storage
2030	AEO 2023	~$3/MMBtu	Final Rule	318	—	1,310	5	733	378	85	1,100	–3
			No 111(b)	299	—	1,339	5	733	356	86	1,099	–2
			No 111(b)/(d)	314	—	1,334	6	739	364	80	1,099	–3
		~$2/MMBtu	Final Rule	322	—	1,383	8	739	313	68	1,100	–3
			No 111(b)	287	—	1,413	7	730	313	71	1,100	–3
			No 111(b)/(d)	296	—	1,420	8	732	313	70	1,099	–3
	IRP Growth	~$3/MMBtu	Final Rule	340	—	1,553	7	739	432	106	1,100	–3
			No 111(b)	334	—	1,581	6	739	414	106	1,099	–3
			No 111(b)/(d)	331	—	1,585	9	739	415	102	1,099	–3
		~$2/MMBtu	Final Rule	382	—	1,537	7	745	405	105	1,100	–3
			No 111(b)	369	—	1,564	6	742	402	98	1,100	–3
			No 111(b)/(d)	367	—	1,585	8	745	380	97	1,099	–3
	IRP with Reduced Renewables	~$3/MMBtu	Final Rule	370	—	1,884	12	745	352	115	786	–3
			No 111(b)	336	—	1,906	12	745	352	119	785	–3
			No 111(b)/(d)	361	—	1,896	12	745	350	123	785	–3
		~$2/MMBtu	Final Rule	522	—	1,718	8	752	369	112	786	–3
			No 111(b)	512	—	1,736	7	745	371	109	786	–3
			No 111(b)/(d)	509	—	1,744	8	745	360	117	786	–3

Table A.4. Total US Generation Across Scenarios (TWh)—Selected Types

Year	Electricity Demand Growth	Delivered Natural Gas Prices	EPA GHG Rules	Existing Coal w/o CCS	Existing Coal w/ retrofit CCS	Combined Cycle	Combustion Turbine	Nuclear	Solar PV	Solar PV + Battery	Onshore Wind	Battery Storage
2035	AEO 2023	~$3/MMBtu	Final Rule	9	202	924	3	637	646	128	1,370	–4
			No 111(b)	9	188	985	2	637	607	127	1,370	–4
			No 111(b)/(d)	287	130	819	2	637	608	125	1,369	–4
		~$2/MMBtu	Final Rule	9	169	1,128	5	629	493	126	1,370	–4
			No 111(b)	9	155	1,178	3	600	494	128	1,370	–4
			No 111(b)/(d)	198	88	1,134	3	576	494	125	1,368	–4
	IRP Growth	~$3/MMBtu	Final Rule	9	218	1,229	5	668	755	154	1,378	–4
			No 111(b)	9	198	1,327	4	665	692	154	1,377	–4
			No 111(b)/(d)	299	131	1,163	3	664	688	149	1,376	–4
		~$2/MMBtu	Final Rule	9	190	1,366	6	675	640	150	1,379	–4
			No 111(b)	9	182	1,420	5	668	609	152	1,379	–4
			No 111(b)/(d)	247	122	1,326	4	660	592	146	1,377	–4
	IRP with Reduced Renewables	~$3/MMBtu	Final Rule	9	218	1,550	6	675	639	174	1,128	–3
			No 111(b)	9	199	1,710	5	668	595	170	1,055	–3
			No 111(b)/(d)	328	145	1,530	5	668	587	165	1,035	–3
		~$2/MMBtu	Final Rule	9	226	1,541	6	675	637	169	1,129	–3
			No 111(b)	9	213	1,659	5	675	589	168	1,082	–3
			No 111(b)/(d)	335	137	1,514	5	668	580	163	1,057	–3

Source: DIEM model.

Table A.5. US Utilization Rates for Existing and New Fossil Units

Year	Electricity Demand Growth	Delivered Natural Gas Prices	EPA GHG Rules	Existing Units: Coal w/o CCS	Existing Units: Coal w/ retrofit CCS	New Units: Combined Cycle w/o CCS	New Units: Combined Cycle w/ CCS
2030	AEO 2023	~$3/MMBtu	Final Rule	38%	44%	87%	87%
			No 111(b)	39%	44%	87%	
			No 111(b)/(d)	39%	47%	87%	
		~$2/MMBtu	Final Rule	36%	47%	87%	87%
			No 111(b)	36%	45%	87%	
			No 111(b)/(d)	38%	48%	87%	
	IRP Growth	~$3/MMBtu	Final Rule	40%	48%	87%	87%
			No 111(b)	41%	46%	87%	
			No 111(b)/(d)	41%	50%	87%	
		~$2/MMBtu	Final Rule	45%	48%	87%	87%
			No 111(b)	45%	45%	87%	
			No 111(b)/(d)	44%	50%	87%	
	IRP with Reduced Renewables	~$3/MMBtu	Final Rule	42%	59%	87%	87%
			No 111(b)	43%	60%	87%	
			No 111(b)/(d)	41%	57%	87%	
		~$2/MMBtu	Final Rule	58%	54%	87%	87%
			No 111(b)	58%	55%	87%	
			No 111(b)/(d)	59%	52%	87%	
2035	AEO 2023	~$3/MMBtu	Final Rule	30%	32%	40%	87%
			No 111(b)	30%	24%	82%	
			No 111(b)/(d)	56%	23%	80%	
		~$2/MMBtu	Final Rule	25%	40%	40%	87%
			No 111(b)	29%	29%	85%	
			No 111(b)/(d)	38%	31%	86%	

Table A.5. US Utilization Rates for Existing and New Fossil Units

Year	Electricity Demand Growth	Delivered Natural Gas Prices	EPA GHG Rules	Existing Units: Coal w/o CCS	Existing Units: Coal w/ retrofit CCS	New Units: Combined Cycle w/o CCS	New Units: Combined Cycle w/ CCS
2035	IRP Growth	~$3/MMBtu	Final Rule	29%	40%	40%	87%
			No 111(b)	29%	27%	82%	
			No 111(b)/(d)	57%	26%	82%	
		~$2/MMBtu	Final Rule	29%	45%	40%	87%
			No 111(b)	29%	29%	85%	
			No 111(b)/(d)	44%	31%	85%	
	IRP with Reduced Renewables	~$3/MMBtu	Final Rule	34%	50%	40%	87%
			No 111(b)	63%	34%	85%	
			No 111(b)/(d)	40%	35%	85%	
		~$2/MMBtu	Final Rule	34%	50%	40%	87%
			No 111(b)	61%	35%	85%	
			No 111(b)/(d)	40%	36%	85%	

Source: DIEM model.

Notes: Units that either retrofit or are built with CCS run at the maximum feasible rate. Utilization rates for combustion turbines average around 1% to 3% as peaking units. A few of the existing combined-cycle units that retrofit with CCS choose to run at maximum feasible rates.

Table A.6a. Regional Capacity Across Scenarios (GW)—Final GHG Rule, $3/MMBtu Natural Gas

Year	Electricity Demand Growth	Region	Existing Coal w/o CCS	Existing Coal w/ Retrofit CCS	Combined Cycle	Combustion Turbine	Nuclear	Solar PV	Solar PV + Battery	Onshore Wind	Battery Storage
2030	AEO 2023	**USA**	**67**	**—**	**312**	**169**	**174**	**33**	**38**	**91**	**304**
		New England	—	—	12	3	5	1	1	3	7
		Middle Atlantic	1	—	37	10	7	3	4	16	13
		South Atlantic	14	—	68	37	57	8	6	26	5
		East North Central	8	—	44	31	15	3	2	16	40
		East South Central	4	—	26	13	6	4	2	12	1
		West North Central	15	—	9	25	2	2	1	4	82
		West South Central	19	—	64	26	25	5	6	9	121
		Mountain	7	—	23	12	25	1	3	4	21
		Pacific	0	—	29	13	32	7	12	1	14
	IRP Growth	**USA**	**72**	**—**	**331**	**187**	**193**	**41**	**42**	**92**	**304**
		New England	—	—	13	3	5	1	1	3	7
		Middle Atlantic	2	—	37	10	9	3	4	16	13
		South Atlantic	16	—	75	37	61	16	10	27	5
		East North Central	8	—	49	31	15	3	2	16	38
		East South Central	4	—	28	13	7		0	12	1
		West North Central	14	—	9	28	2	2	1	4	83
		West South Central	20	—	63	39	36	6	7	9	121
		Mountain	8	—	28	11	29	1	4	4	21
		Pacific	0	—	30	13	31	9	13	1	14

Table A.6a. Regional Capacity Across Scenarios (GW)—Final GHG Rule, $3/MMBtu Natural Gas

Year	Electricity Demand Growth	Region	Existing Coal w/o CCS	Existing Coal w/ Retrofit CCS	Combined Cycle	Combustion Turbine	Nuclear	Solar PV	Solar PV + Battery	Onshore Wind	Battery Storage
2030	IRP with Reduced Renewables	**USA**	**76**	**—**	**341**	**174**	**161**	**46**	**45**	**93**	**229**
		New England	—	—	13	3	4	1	1	3	6
		Middle Atlantic	2	—	37	10	8	3	4	16	10
		South Atlantic	16	—	76	38	39	19	12	27	5
		East North Central	7	—	49	28	14	9	5	16	25
		East South Central	5	—	29	13	3		0	12	0
		West North Central	19	—	13	24	3	1	1	5	60
		West South Central	20	—	66	35	34	4	5	9	88
		Mountain	7	—	29	10	25	1	4	4	21
		Pacific	0	—	30	13	30	9	13	1	14
2035	AEO 2023	**USA**	**0**	**42**	**318**	**228**	**269**	**49**	**47**	**79**	**368**
		New England	—	—	12	3	5	1	1	3	7
		Middle Atlantic	0	1	37	10	7	3	4	13	17
		South Atlantic	—	10	69	44	109	14	9	25	6
		East North Central	0	4	49	36	16	3	2	15	54
		East South Central	—	3	26	18	14	6	4	10	1
		West North Central	0	1	9	43	4	3	2	1	99
		West South Central	0	17	64	43	45	7	7	6	148
		Mountain	—	5	23	17	29	4	6	4	21
		Pacific	0	—	29	13	42	8	13	1	14

Table A.6a. Regional Capacity Across Scenarios (GW)—Final GHG Rule, $3/MMBtu Natural Gas

Year	Electricity Demand Growth	Region	Existing Coal w/o CCS	Existing Coal w/ Retrofit CCS	Combined Cycle	Combustion Turbine	Nuclear	Solar PV	Solar PV + Battery	Onshore Wind	Battery Storage
2035	IRP Growth	**USA**	**0**	**45**	**351**	**255**	**310**	**59**	**53**	**82**	**370**
		New England	—	—	13	5	5	1	1	3	7
		Middle Atlantic	0	2	37	15	8	3	4	15	19
		South Atlantic	—	12	80	49	124	20	13	25	7
		East North Central	0	4	62	37	16	3	2	15	52
		East South Central	—	3	29	13	21	2	1	10	1
		West North Central	0	1	9	47	8	4	2	1	101
		West South Central	0	18	63	55	51	9	8	8	148
		Mountain	—	5	28	17	36	5	6	4	21
		Pacific	0	—	31	17	41	12	15	1	14
	IRP with Reduced Renewables	**USA**	**0**	**45**	**365**	**235**	**263**	**67**	**58**	**83**	**310**
		New England	—	—	13	5	4	1	1	3	7
		Middle Atlantic	0	2	37	15	9	3	4	15	18
		South Atlantic	—	12	83	46	81	26	16	26	10
		East North Central	0	4	62	32	15	9	5	15	39
		East South Central	—	3	29	13	15		0	10	0
		West North Central	0	1	13	43	7	3	2	1	76
		West South Central	0	18	66	51	55	9	8	8	125
		Mountain	—	5	31	14	40	5	6	4	21
		Pacific	0	—	31	17	37	12	15	1	14

Table A.6b. Regional Capacity Across Scenarios (GW)—No 111(b) or 111(d), $3/MMBtu Natural Gas

Year	Electricity Demand Growth	Region	Existing Coal w/o CCS	Existing Coal w/ Retrofit CCS	Combined Cycle	Combustion Turbine	Nuclear	Solar PV	Solar PV + Battery	Onshore Wind	Battery Storage
2030	AEO 2023	**USA**	**93**	**—**	**306**	**168**	**168**	**31**	**36**	**92**	**304**
		New England	—	—	12	3	4	1	1	3	7
		Middle Atlantic	1	—	37	10	7	3	4	16	13
		South Atlantic	21	—	69	36	55	9	7	27	5
		East North Central	13	—	41	30	15	3	2	16	40
		East South Central	6	—	25	13	5	3	2	12	1
		West North Central	22	—	8	26	2	1	1	4	81
		West South Central	20	—	63	25	25	4	5	9	121
		Mountain	9	—	23	12	24	0	3	4	21
		Pacific	0	—	28	13	32	8	13	1	15
	IRP Growth	**USA**	**93**	**—**	**330**	**182**	**187**	**40**	**42**	**92**	**304**
		New England	—	—	13	3	5	1	1	3	7
		Middle Atlantic	1	—	37	10	9	3	4	16	13
		South Atlantic	21	—	78	36	57	16	11	27	6
		East North Central	13	—	48	30	15	3	2	16	37
		East South Central	6	—	28	13	7		0	12	1
		West North Central	23	—	7	30	2	1	1	4	81
		West South Central	20	—	63	35	34	5	6	9	123
		Mountain	10	—	27	11	28	1	4	4	21
		Pacific	0	—	29	13	31	9	14	1	15

Table A.6b. Regional Capacity Across Scenarios (GW)—No 111(b) or 111(d), $3/MMBtu Natural Gas

Year	Electricity Demand Growth	Region	Existing Coal w/o CCS	Existing Coal w/ Retrofit CCS	Combined Cycle	Combustion Turbine	Nuclear	Solar PV	Solar PV + Battery	Onshore Wind	Battery Storage
2030	IRP with Reduced Renewables	USA	96	—	340	170	160	49	47	93	229
		New England	—	—	13	3	4	1	1	3	6
		Middle Atlantic	1	—	37	10	8	3	4	16	10
		South Atlantic	21	—	79	36	39	20	13	27	5
		East North Central	12	—	47	28	13	9	5	16	24
		East South Central	7	—	30	13	3		0	12	0
		West North Central	24	—	13	24	3	1	1	5	60
		West South Central	21	—	63	33	35	5	6	9	89
		Mountain	10	—	28	10	25	1	4	4	21
		Pacific	0	—	29	13	30	9	14	1	15
2035	AEO 2023	USA	59	27	321	187	254	48	46	79	368
		New England	—	—	12	3	5	1	1	3	7
		Middle Atlantic	1	0	37	10	7	3	4	13	17
		South Atlantic	11	9	74	33	99	14	9	25	6
		East North Central	10	3	48	34	16	3	2	15	54
		East South Central	5	0	28	13	10	5	3	10	3
		West North Central	19	0	8	30	2	2	1	1	97
		West South Central	9	10	63	35	44	7	7	6	149
		Mountain	4	4	23	15	28	4	5	4	21
		Pacific	0	—	29	13	44	9	13	1	15

Table A.6b. Regional Capacity Across Scenarios (GW)—No 111(b) or 111(d), $3/MMBtu Natural Gas

Year	Electricity Demand Growth	Region	Existing Coal w/o CCS	Existing Coal w/ Retrofit CCS	Combined Cycle	Combustion Turbine	Nuclear	Solar PV	Solar PV + Battery	Onshore Wind	Battery Storage
2035	IRP Growth	**USA**	**59**	**27**	**359**	**212**	**284**	**56**	**52**	**82**	**370**
		New England	—	—	13	5	5	1	1	3	9
		Middle Atlantic	1	0	37	15	8	3	4	14	19
		South Atlantic	11	9	90	35	114	19	13	25	8
		East North Central	10	3	62	35	16	3	2	15	50
		East South Central	5	0	28	13	12	1	1	10	1
		West North Central	20	0	7	34	3	3	2	1	98
		West South Central	9	10	65	44	51	9	8	8	150
		Mountain	4	4	28	15	33	5	6	4	21
		Pacific	0	—	31	17	44	12	15	1	15
	IRP with Reduced Renewables	**USA**	**60**	**30**	**376**	**195**	**243**	**64**	**56**	**82**	**288**
		New England	—	—	13	5	5	1	1	3	7
		Middle Atlantic	1	0	37	15	9	3	4	15	16
		South Atlantic	11	9	90	34	73	21	14	25	8
		East North Central	9	3	65	29	15	9	5	15	31
		East South Central	5	1	30	13	14	1	1	10	0
		West North Central	21	0	13	28	3	3	2	1	68
		West South Central	9	12	66	42	50	9	8	8	121
		Mountain	4	4	31	12	33	4	6	4	21
		Pacific	0	—	31	17	42	13	15	1	15

Table A.7. Selected Electricity Demand Forecasts, Summaries of the Level of Detail Provided

IRP and/or Forecast	IRP Year	Included Years	Scenarios				Peaks (if coincident)			Energy		Sectoral Detail and DR Types
			Baseline	High Growth	Low Growth	Other	Winter	Summer	Unspecified	Net Load	Retail Sales	
Arizona Public Service	2023 (every 3 years)	2023–2038	X	—	—	Weather	—	—	X	X	X	Multiple
Alabama Power	2022	2021–2041	X	—	—	—	X	X	—	—	—	None
California CEC	2023	2000–2040	X	—	—	Reliability	X	X	—	X	X	Multiple
Colorado Xcel	2023	2032–2032	X	—	—	—	X	—	—	X	—	None
ERCOT (TX)	2024	2024–2033	X	—	—	Weather	X	X	—	X	—	None
Georgia Power	2023 IRP Update	2024–2043 (graph)	X	—	—	—	X	—	—	—	—	None
Duke DEC/DEP	Updated 2023	2024–2038	X	X	—	—	X	—	—	X	X	Large/EV/DR
Santee Cooper	2023 Addendum	2023–2041	X	X	X	—	X	—	—	X	—	Industry/Other
Dominion South Carolina	2023	2023–2037	X	—	—	—	X	X	—	—	X	None
Florida (Duke)	2024	2024–2033	X	X	X	—	X	X	—	X	X	Multiple
Florida (FPL)	2024	2024–2033	X	—	—	—	X	X	—	X	X	Multiple
Florida (Tampa TECO)	2024	2024–2033	X	X	X	—	X	X	—	X	X	Multiple
ISO New England	2024	2024–2033	X	—	—	—	X	X	—	X	—	EV/Other
Kentucky LGE/KU	2021	2022–2036	X	—	—	—	X	X	—	X	—	None
Duke Kentucky	2024	2024–2045	X	X	X	—	—	X	—	X	—	None
Kentucky KYME	*2023*	*In progress*	—	—	—	—	—	—	—	—	—	—
Entergy Louisiana	2023	2023–2042	X	—	—	Several	X	X	—	—	—	Multiple
MISO (Purdue forecast for MS)	2023	1990–2043	X	X	X	—	—	—	—	X	—	None

Table A.7. Selected Electricity Demand Forecasts, Summaries of the Level of Detail Provided

IRP and/or Forecast	IRP Year	Included Years	Scenarios				Peaks (if coincident)			Energy		Sectoral Detail and DR Types
			Baseline	High Growth	Low Growth	Other	Winter	Summer	Unspecified	Net Load	Retail Sales	
Mississippi Power Company	*2024*	*In progress*	—	—	—	—	—	—	—	—	—	—
NYCA	2024 prelim	2024–2054	X	X	X	—	X	X	—	X	X	Large/EV/DR
Nevada Power	2024	2023–2044	X	—	—	—	—	—	X	—	—	DR
RMPA	2023	2024–2042	X	—	—	—	X (w/o DSM)	—	—	—	X	Multiple
SPP	2024	2024–2029	X	—	—	—	—	—	X	—	—	DR
TVA (Synapse Energy Econ)	2023	2020, 2035, 2050	X	—	—	100% Clean	—	—	—	X	—	None
TVA IRP	*2025 update*	*In progress*	—	—	—	—	—	—	—	—	—	—
Dominion Virginia	2023	2023–2048	X	—	—	—	—	X	—	—	—	None
PJM	2024	2024–2039	X	—	—	Weather	X	X	—	X	—	None
West Virginia FirstEnergy	—	—		*Used PJM data*			—	—	—	—	—	—
West Virginia AEP	—	—		*Used PJM data*			—	—	—	—	—	—