Model Comparisons for Potential Impacts of the IRA on the U.S. Power Sector

2023

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Acknowledgements

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This report was developed by ERM on behalf of the Center for Applied Environmental Law and Policy (CAELP).

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Acronyms and Abbreviations

Name	Description
BAU	Business-as-usual
CAELP	Center for Applied Environmental Law and Policy
CCS	Carbon capture and storage
CO_2	Carbon dioxide
CT	Combustion turbines
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
ERM	Environmental Resources Management, Inc.
GW	Gigawatt
IRA	Inflation Reduction Act
ITC	Investment Tax Credit
kW	Kilowatt
MT	Metric ton
NGCC	Natural gas combined cycle
NRDC	Natural Resources Defense Council
NREL	National Renewable Energy Laboratory
PTC	Production Tax Credit
RFF	Resources for the Future
TWh	terawatt hours

INTRODUCTION

Purpose

In May 2023, the U.S. Environmental Protection Agency (EPA) proposed greenhouse gas emissions standards for fossil fuel-fired power plants under section 111 of the Clean Air Act. In an effort to understand how these regulations may affect the power sector, it is useful to first understand how the market outlook may change due to other recently enacted policies. The objective of this report is to enhance understanding of the likely business-as-usual (BAU) power sector implications of new incentives available from the Inflation Reduction Act (IRA), analyzed in late 2022 and early 2023. This may provide a clearer range of potential futures for the power sector absent EPA regulations to shed more light on how new regulations may further affect U.S. power supply.

Approach

Environmental Resources Management, Inc. (ERM) gathered publicly available data as of early 2023 from a variety of studies that analyzed impacts of the IRA on the power sector using a range of models. ERM also conducted outreach to relevant experts from the modeling teams to acquire additional background information, assumptions, data, and other applicable details about the studies conducted.

Studies discussed in this memo are listed in the References section and include those where there was sufficient data to analyze and compare to other studies. Seven organizations prepared early analyses of the IRA and their studies are discussed herein, including the Center for Applied Environmental Law and Policy (CAELP), the Electric Power Research Institute (EPRI), Energy Innovation, Natural Resources Defense Council (NRDC),[1] the National Renewable Energy Laboratory (NREL), Resources for the Future (RFF), and Rhodium Group. [2]

ERM divided the following review of results into three main sections:

- **Intra-model comparison** of a BAU IRA Scenario to previous BAU No IRA Scenario results to assess potential change in the baseline due to IRA within a given study's own modeling framework;
- **Inter-model comparison** of IRA Scenario results across different studies to overview the potential range of impacts on the power sector from the IRA as seen in different modeling frameworks; and
- **Discussion** of findings from review of these early results of modeling the IRA.

Model Considerations

Importantly, all models reviewed are optimized and represent purely economic frameworks that produced a scenario based on a set of assumptions. The quantitative results are heavily influenced by each model's ability to have perfect foresight into the future regarding costs and policies, which optimize decision-making. Relatedly, each developer has designed its model to approximate the same real-world conditions differently from other models. This impacts the results from a given model, but these design dynamics are difficult to understand for their true influence on a model's own scenario results, let alone to compare designs and influence across different models' results. Furthermore, model results become less certain when looking at projections further into the future. This report presents available results through 2040, though projections through 2030 may be more informative than relying on data that is further out.

[1] This review of available studies was conducted at the beginning of 2023. Multiple studies, including CAELP, NRDC, and Energy Innovation have subsequently updated the business-as-usual and other scenario projections to reflect more recently available data and assumptions, as well as to refine power sector representation in models.

[2] Additional analyses from Princeton University, Bloomberg New Energy Finance, McKinsey, and S&P were reviewed but are not included in this report due to insufficient information available specific to the power sector or due to other data access limitations.

Additionally, certain real-world considerations are often not fully accounted for in a model (nor can they be), therefore results can sometimes be more a function of model constraints and economic assumptions than what may most realistically happen in reality. Some of these model results may be unable to wholly account for certain considerations that are difficult to analyze such as supply chain constraints, the timeline of permitting procedures, transmission needs and costs, or every available resource investment option (e.g., facility upgrades, retrofits, conversions, etc.).

Relatedly, various government guidance procedures for implementation of the IRA have not yet been finalized, therefore each study is inherently making best-guess assumptions about how certain provisions will work in practice. Most studies captured power sector supply-side incentives from the IRA, but incentives that will impact demand, such as transportation and building electrification, are more difficult to project and incorporate into modeling. It is also worth noting that the IRA includes new federal incentives for hydrogen production, but end-use sectors driving demand are uncertain and will depend on a combination of factors. None of the studies reviewed assumed hydrogen demand in the power sector in their main or central IRA scenarios. Ultimately, uncertainties around implementation of the IRA could drive a range of potential futures, and the study results reviewed here provide insight into a handful of potential modeled outcomes. This review focused on the main or central BAU scenario from each study, though variations on assumptions (e.g., different representation of costs or policies impacting capacity changes) would give different results, which highlights the importance of scenario analysis, but also the uncertainty of it.

Key Learnings

- All studies reviewed suggested the IRA will economically incentivize and bring about emissions reductions by supporting cleaner resource types over conventional technologies. However, absent additional policies, some modeling suggested that while implementation of the IRA supports emissions reductions in the coming years, emissions could increase farther in the future once the IRA credits phase out.
- The IRA will significantly increase the share of power generation from clean resources (zero-emitting resources and fossil fuel plus carbon capture and storage [CCS]) and support emissions reductions, though the exact timing and extent of the impacts varied across studies:
    - Modeling suggested the IRA could result in clean resources accounting for 56-78 percent of generation in 2030 and 68-91 percent in 2040, compared to 37 percent historically in 2021.
    - Without the IRA, the power sector is on a path to achieve carbon dioxide (CO_2) emissions reductions 47-59 percent below 2005 levels by 2030. Modeling suggested the IRA could help drive down power sector CO_2 emissions 58-81 percent below 2005 levels by 2030.
- Certain clean resources were deployed in all studies, while other resources were only deployed in some studies, likely based on economic assumptions.
    - For studies that directly modeled battery storage, all found greater deployment with support from the IRA compared to BAU without the IRA.
    - Some models did not deploy any CCS at fossil fuel-fired power plants due to high cost assumptions. Other studies found the IRA helped support CCS deployment in the BAU scenario, especially as retrofits to existing power plants due to lower capital costs compared to new builds.
- Transformational change to the power sector may only occur through sustained technology cost reductions over time, especially if/as IRA credits expire, and by surmounting real-world barriers not addressed directly by the IRA or by modeling efforts, such as supply-chain constraints.

- The degree to which various resources will be deployed will depend on a number of factors reflected in the modeling, such as technology costs and incorporation of IRA provisions, including level of load growth.
  - Broadly, most studies that assumed higher natural gas prices, coupled with lower renewable technology costs resulted in a grid mix with greater deployment of clean resources and lower levels of emissions across the modeled time horizon.
  - The IRA will incent more supply of cleaner technologies, but conventional resources, such as natural gas combustion turbines, were still likely to be needed in models, such as to help maintain reliability and balance intermittent renewables.
  - Few studies incorporated the IRA's demand-side electrification policies as the estimated impacts of these on demand growth are difficult to quantify and assumptions varied by study. Changes to power sector demand growth could further impact the supply mix compared to the available study results.
- There are also real-world barriers to consider that may not be accounted for or accurately represented in the modeling.
  - Most modeling that incorporated the nuclear production tax credit (PTC) from the IRA found a significant drop off in nuclear capacity immediately after the credits expire, around 2032. The level of retirement in such a short time frame seen in many studies is unlikely to happen, but greatly impacted the model results.
  - In 2021, 15 gigawatts (GW) of solar and 12 GW of wind capacity were added to the U.S. power sector. Modeling suggested the IRA could drive two to three times these additions in each year over the next decade. However, this modeled year-over-year increase incented by the IRA could be constrained by real-world challenges not fully captured in modeling such as supply chain constraints, slow-moving permitting queues, and related transmission availability and build costs.

INTRA-MODEL COMPARISON

This section compares various studies' main or central IRA Scenario to their own No IRA Scenario to assess potential change in BAU due to the IRA within a given study and model.

Power Sector Emissions

As Figure 1 shows, the reviewed studies agree that by 2030 and beyond, power sector CO_2 emissions fell as a result of the IRA. In the immediate term, however, some studies show an emissions increase. CAELP, NRDC, and Rhodium each projected increased emissions for 2025 under the IRA scenario compared to the scenario without the IRA, potentially due to delayed build out of renewables in the IRA scenario as credits were assumed to improve later in the decade. In contrast, the other studies projected emissions reductions in all years. RFF projected the largest short-term reductions of over 300 million metric tons (MT) of CO_2 in 2025 compared to the No IRA Scenario due to early and fast-paced deployment of renewables.

For the year 2030, modeling of the IRA found that 250 million MT of CO_2 (NRDC) to more than 800 million MT of CO_2 (NREL) of CO_2 could be avoided from the power sector compared to projections without the IRA for this year. Five years later saw an additional 60 million MT of CO_2 reduced on average for 2035. Cumulatively between 2025 through 2035, studies found that the IRA could avoid roughly 3 to 7 billion MT from being emitted to atmosphere compared to BAU projections without the IRA.

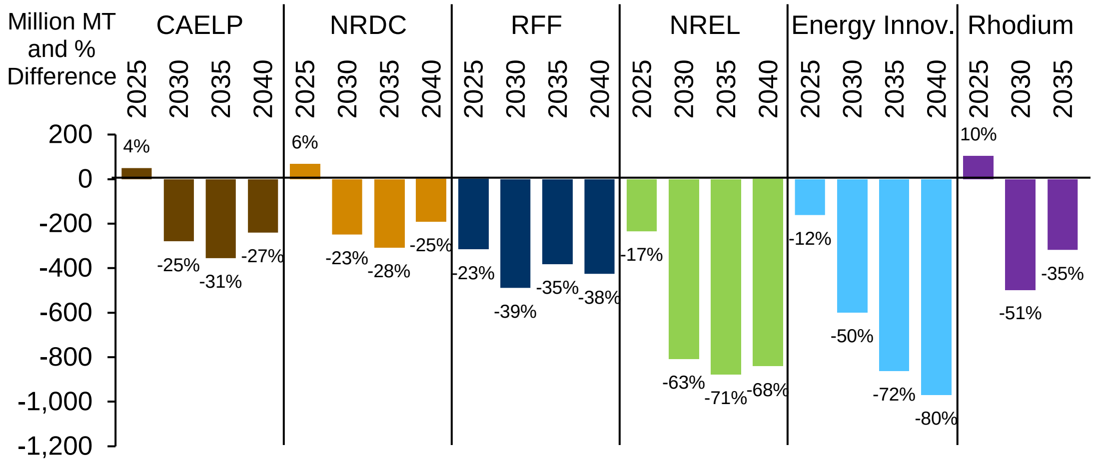

Figure 1: Power Sector CO_2 Emissions in Select Years: Emissions in IRA Scenario minus Emissions in No IRA Scenario

Grid Mix

The directional impact of the IRA was the same in all studies, with clean resources becoming a greater share of the grid mix as fossil-fired resources declined. However, the exact timing and extent of the impacts varied by study.

Renewables and Storage

Wind and Solar. Without the IRA, all studies reviewed still projected generation from renewables (wind and solar) to grow over the next two decades as costs were assumed to decline even without incentives, and state-level policies increasingly drive renewable uptake. Figure 2 shows that in the No IRA Scenario in each of various studies, there were similar levels of wind plus solar through time, with more than double current generation from renewables by 2030, and most showed more than triple by 2035. Once the IRA was modeled, renewable generation varied widely by study. CAELP and NRDC both modeled using the Integrated Planning Model (IPM) and each found renewable generation in the IRA scenario to be more than 30 percent greater than in the No IRA Scenario in 2035; or more than quadruple 2021 levels. Rhodium and RFF projected an increase of 65 percent and 50 percent over each No IRA Scenario in 2035. However, Energy Innovation and NREL modeling of the IRA suggested a more significant increase in generation from renewables. Energy Innovation found more than eight times 2021 levels in 2035, or nearly three times the generation for 2035 compared to the No IRA Scenario. These two studies also projected the highest levels of power generation (i.e., greatest amount of demand growth) compared to the other studies for both scenarios, but especially in the IRA scenario (see Figure 10) due to inclusion of demand-side incentives, which were not captured in most other studies reviewed.

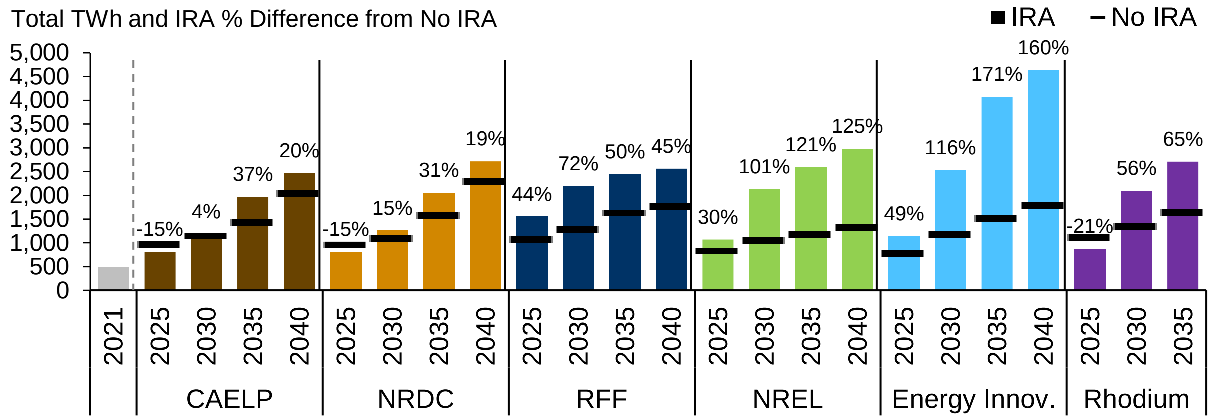

Figure 2: Wind + Solar Generation for IRA and No IRA Scenarios

Many studies assumed largely similar cost inputs for renewables (the NREL Annual Technology Baseline [ATB] mid case) and represented the IRA clean energy incentives in largely similar ways (see Table 1 in Appendix A). CAELP and NRDC results were on the lower end of clean power growth and relied on an older NREL ATB data set with slightly higher capital costs for renewables as compared to many of the other studies' assumptions (see Figure 18). There were other differentiators in these studies' generation results that may also be more a function of the need to meet different assumed levels of demand growth as opposed to purely economic differences across the studies.

Battery Storage. The studies that directly modeled storage and provided data on installed capacity uniformly projected significant growth in the IRA Scenario compared to No IRA. Other studies did not provide sufficient information to derive an intra-model comparison. For those with sufficient data, Figure 3 demonstrates the economic support the IRA may provide to enhance storage deployment. In 2035, an additional 30 to over 120 GW of more battery storage may be available with the IRA, or on average roughly double the total capacity installed in No IRA Scenarios by 2035.

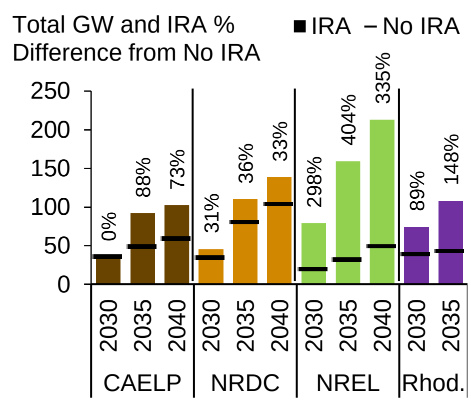

Figure 3: Storage Installed Capacity for IRA and No IRA Scenarios

Nuclear

The IRA includes a PTC for nuclear generation available to facilities in service in 2024 and lasting through 2032. As Figure 4 shows, modeling of the IRA broadly appears to have had no impact on nuclear generation in the near-term, with projected generation to be the same in either BAU scenario, resulting in levels similar to recent history. Then by 2030, most studies found support from the IRA for keeping nuclear online as generation was higher in this model year for most IRA scenarios compared to No IRA. However, as the models reached the timing of the PTC expiration, impacts were mixed. Many of the models' central IRA scenarios showed a significant decrease in nuclear generation by 2035.

Energy Innovation and Rhodium saw dramatic decreases in nuclear generation in 2035 compared to 2030 under the IRA, but each report's No IRA Scenario saw only a modest decrease driven by known announced retirements. The CAELP and NRDC studies both resulted in a substantial fall in nuclear generation in 2035 under both the IRA and No IRA Scenarios, but the No IRA Scenario in the CAELP study projected more generation for the model year. RFF and NREL showed minimal-to-no impact of the IRA on nuclear generation and resulted in only a modest decrease across the study period. RFF noted that the PTC for existing nuclear was not represented directly and that associated government expenditures were also not represented. For the IRA scenario, their Haiku model assumed nuclear generation was fixed to the baseline to represent support for the existing fleet and therefore the fleet saw no change between the two scenarios. RFF's BAU baseline incorporated known announced retirements (not accounting for California's Diablo Canyon life extension), and the Civil Nuclear Credit Program, passed as part of the Infrastructure Investment and Jobs Act (IIJA). Other studies incorporated this IIJA program as well, which may have helped to support nuclear economics post-2030 in No IRA Scenarios.

The costs of different technologies as time goes on may have a meaningful impact on the nuclear fleet in the future. However, some of the significant retirements seen in most studies in the mid-2030s may be driven by the models' reliance purely on economic assumptions to inform grid mix and the results may be unlikely to occur due to a variety of considerations not fully accounted for in these scenarios, such as supply chain constraints, the timeline of permitting procedures for new entrants, transmission needs, and more. See the below discussion section on IRA incentives for more on nuclear retirements.

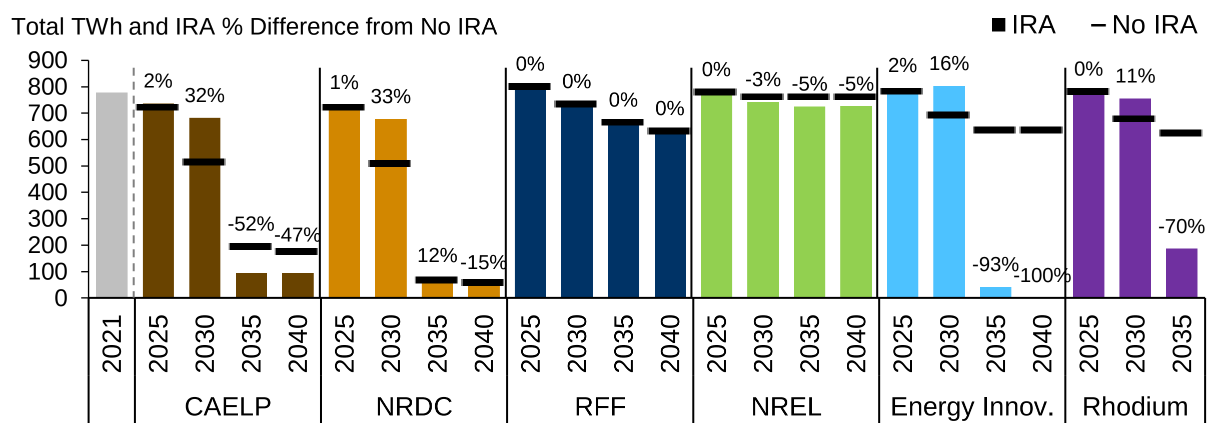

Figure 4: Nuclear Generation for IRA and No IRA Scenarios

Coal

Coal generation generally fell over time in the models regardless of whether they included the IRA, implying announced retirements as well as sector economics are already driving out coal. However, the IRA, as reflected in available modeling, did drive down coal further and faster. Figure 5 shows coal generation by study and scenario, as available. On average, in 2030, coal generation declined from 2021 levels by nearly 40 percent without the IRA, but more than 70 percent with the IRA.

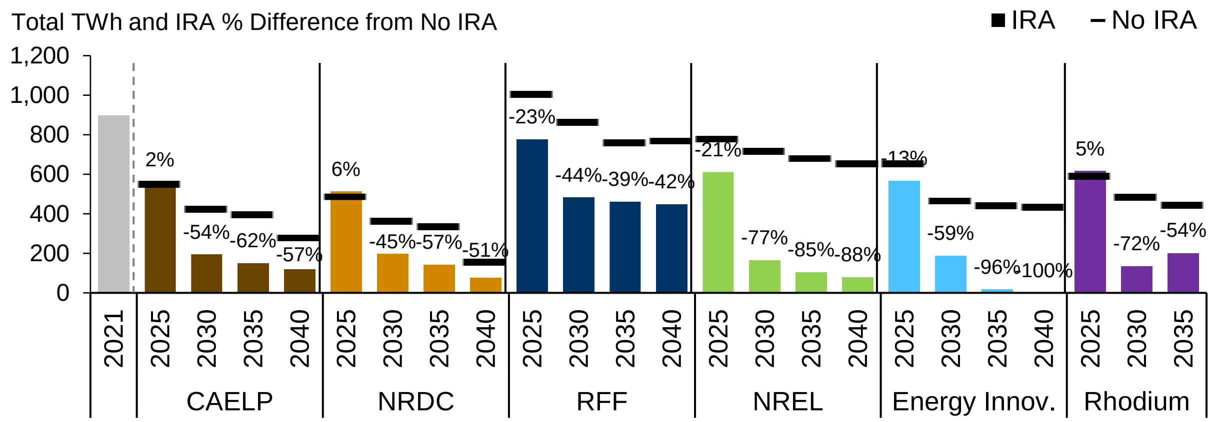

Figure 5: Coal Generation for IRA and No IRA Scenarios

Natural Gas

The impact of the IRA on natural gas varied across the models. The factors driving this are complex and relate to data inputs, how the IRA is modeled, as well as how the models function generally. Some available data for select studies on installed capacity and generation is included in Figure 6 below. Some studies found reduced gas capacity and generation in the IRA scenario compared to the No IRA Scenario, perhaps implying declining costs of other technologies plus incentives from the IRA help other resources to become more economic compared to gas. Uniquely, Rhodium added more gas capacity in its IRA scenario (left chart) and dispatched the units less, resulting in lower generation (right chart). The model might have kept more gas capacity online in the IRA scenario to support variable renewables, though there is not sufficient data detail to know the type of gas capacity to know if it is or is not mostly peaking. The Rhodium and NREL studies also found that generation from gas ramps up into the later 2030s as various clean energy incentives from the IRA phase-out. See inter-model comparison and discussion sections below for more on this.

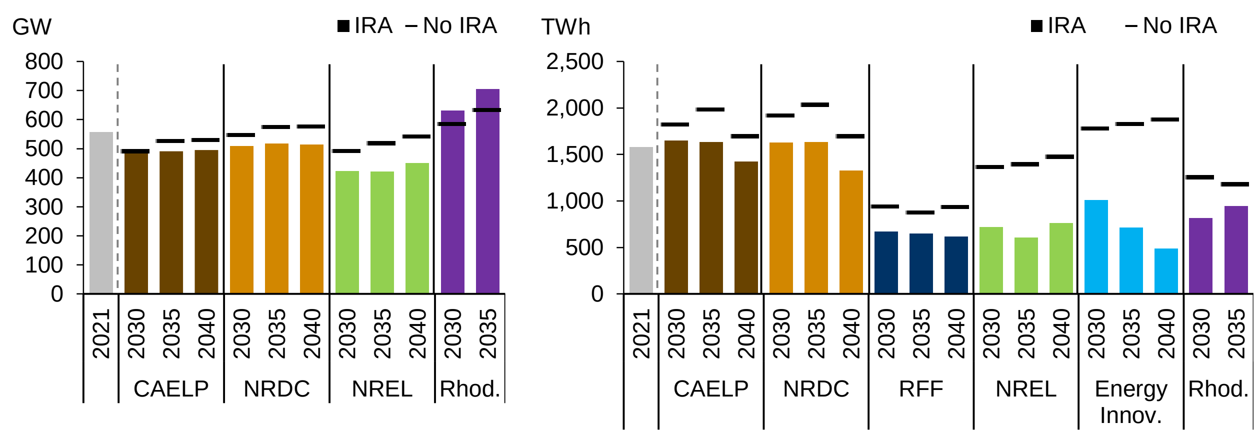

Figure 6: Natural Gas Installed Capacity (left) and Generation (right) for IRA and No IRA Scenarios

Some model results provided more detail than others on the type of gas capacity, distinguishing baseload natural gas combined cycle (NGCC) units from peaker combustion turbines (CT). Figure 7 shows estimated average annual builds for select studies from 2023 through 2030, and separately from 2031 through 2035. CAELP, NRDC, and Energy Innovation all found that more NGCC units were built in the No

IRA Scenario across the selected periods compared to builds in the IRA Scenarios. This implies that gas as a baseload resource becomes less necessary or economic compared to other technologies given incentives from the IRA. On the other hand, the three studies all built more CTs, especially post-2030, in each of their own central IRA Scenario compared to CT builds in the No IRA Scenario. This capacity is relevant in the future to support peaking demand and significantly greater amounts of intermittent renewables incented by the IRA. Energy Innovation's modeling built significantly more peaking capacity compared to other studies, but also had the highest level of demand growth (see Figure 11) due to inclusion of demand-side incentives, which were not captured in most other studies reviewed, and also had more renewables than other studies by 2035. [3] Energy Innovation's Energy Policy Simulator (EPS) model has certain units that it qualifies as peakers (such as gas-fired CTs), and the model chooses what to build as informed by levelized cost of energy of various resource options to first meet total demand then peak demand (including a reserve margin).

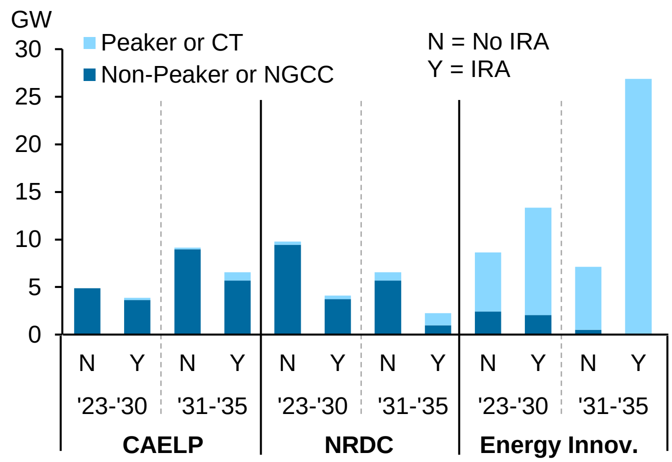

Figure 7: Average Annual Natural Gas Builds for Select Time Periods

No studies deployed gas with CCS in their central No IRA Scenario, though three did in their central IRA Scenario, compared below, including NREL, NRDC, and EPRI. See inter-model comparison and discussion sections below for more.

INTER-MODEL COMPARISON

This section compares the IRA Scenario results across different studies and available data to assess the potential range of impacts on the power sector from the IRA, as seen in different modeling frameworks.

Power Sector Emissions

Power sector CO_2 emissions trends from available studies incorporating the IRA are charted through 2040 in Figure 8 below. As a point of reference, sector emissions totaled 2,401 million MT of CO_2 in 2005.[4] Across the studies compared, projected emissions decline 58 to 81 percent below 2005 levels by 2030 as a result of implementation of the IRA. For comparison, studies' central No IRA Scenario reduced emissions from 2005 levels 47 percent to at most 59 percent (not shown).

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[3] This review of available studies was conducted at the beginning of 2023. Since the publication of this report, Energy Innovation has begun updating power sector representation in its model and may find reduced deployment of CTs in future analyses.

[4] Historical 2005 power sector CO_2 emissions from EIA State profiles and Monthly Energy Review.

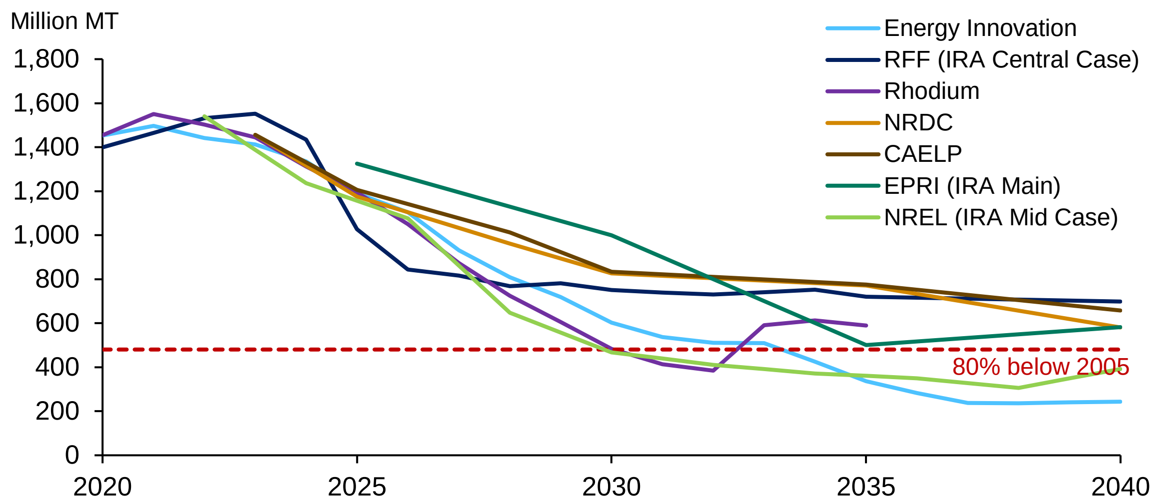

Figure 8: Projected CO_2 Emissions Trends from Available IRA Scenarios

Noteworthy elements of the various results include:

- EPRI's Main IRA scenario (dark green line), resulted in the lowest amount of reductions, or highest emissions levels in 2030 of 1 billion MT of CO_2, or a 58 percent reduction from 2005 levels. Emissions dropped in this study to nearly 80 percent below 2005 levels by 2035, resulting in an emissions trajectory for the later years of roughly the average of all studies reviewed.
- Energy Innovation's IRA scenario (bright blue line) consistently resulted in low emissions over time compared to most other studies with a 75 percent reduction from 2005 levels by 2030, 86 percent reduction by 2035, and 90 percent reduction by 2040.
- CAELP and NRDC (gold lines) projected similar outcomes to each other, both resulting in power sector CO_2 of roughly 66 percent below 2005 levels in 2030, with minimal additional reductions afterward.
- RFF's IRA Central Case (dark blue line) resulted in the most dramatic drop in the early years, removing over 700 million MT of CO_2 from 2023 to 2026, reflecting a significant transition in the energy mix from fossil-fired resources to renewables during this time. In 2026, resulting emissions were 65 percent below 2005 levels, but only minorly continued to decline from here for 71 percent reduction in 2040.
- Rhodium (purple line) and NREL (light green line) achieved the greatest reduction of 80 percent and 81 percent, respectively, below 2005 levels by 2030. Emissions then increased in Rhodium toward 2035 as incentives from the IRA were no longer available. These two studies captured the IRA provision ending clean energy incentives once power sector CO_2 emissions decline 75 percent below 2022 levels. CAELP and NRDC also incorporated this 75 percent provision, and since it was not reached in the time horizon shown, the clean energy incentives remained available. All other studies deployed a simplified assumption of incentive phase-out beginning in 2032. Rhodium's model began to ramp up fossil-fired resources quickly after the clean energy incentives expired a few years before 2035, while NREL's continued mild emissions reductions through much of the 2030s with emissions increasing in the late 2030s into the 2040s. These results illustrate that while the IRA may drive clean energy build out, emissions from the fossil-fired fleet could still increase in the future in the absence of direct regulation.

In addition to CO_2, many of the studies also modeled co-pollutant emissions from power plants, including sulfur dioxide (SO_2) and nitrogen oxides (NOx), as shown in Figure 9.[5]

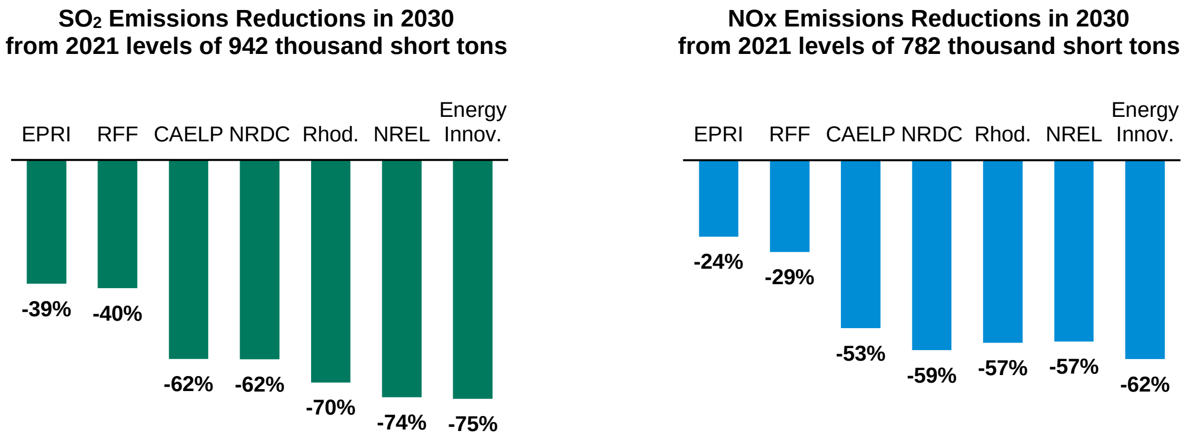

Figure 9: 2030 SO_2 and NOx Emissions Reductions from 2021 Levels Across Available IRA Scenarios

Observations from these co-pollutant results include:

- In 2021, power plant SO_2 emissions totaled 942 thousand short tons. The studies that projected SO_2 resulted in emissions in 2030 ranging from 577 down to 239 thousand short tons, or 39 percent to 75 percent below 2021 levels.
- Notably, when comparing coal generation and co-pollutant emissions across models, the models with the least amount of coal generation (or having greater retirements of existing coal units) resulted in the lowest co-pollutant emissions.
- Similarly, NOx emissions varied across models as well, ranging from 595 down to 296 thousand short tons in 2030, or 24 percent to 62 percent below 2021 emissions of 782 thousand short tons. This decline in emissions also correlated with declining coal generation.

Generation Mix

Across the studies' IRA scenarios, power generation from low- and zero-emitting resources increased rapidly from now into the 2030s and slowed in the longer-term as incentives from the IRA phase-out. Clean resources (including low- and zero-emitting resources of nuclear, hydro, wind, solar, and fossil plus CCS) accounted for 37 percent of power generation in 2021. As shown in Figure 10, modeling incorporating the IRA projects the mix of clean resources as accounting for 57-78 percent of power generation by 2030, and 65-91 percent by 2040.

[5] Historical 2021 power sector SO_2 and NOx emissions from EPA Clean Air Markets Data, https://www.epa.gov/airmarkets/power-plant-emission-trends.

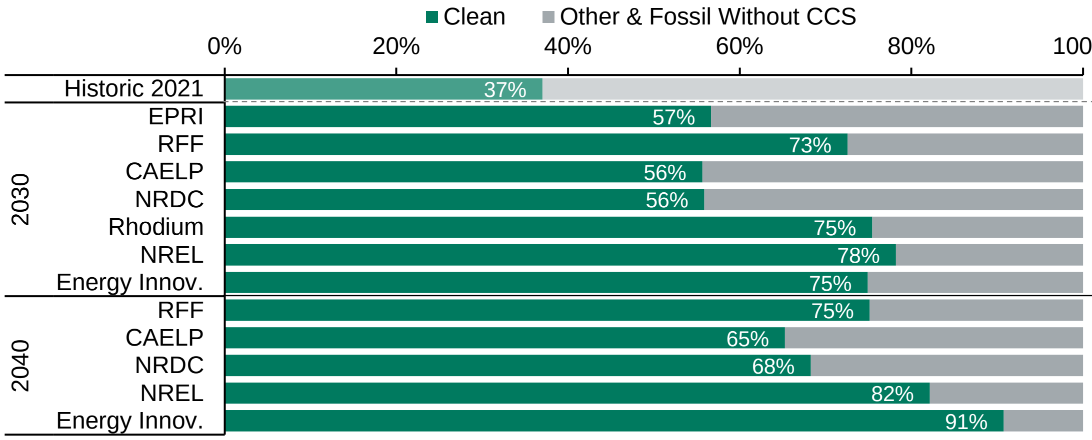

Figure 10: Clean Resources share of Generation

While the overall level of clean generation varied widely, so did the generation mix. See Figure 11 for available generation mix from the seven studies' IRA scenarios reviewed. Summary observations of the range of generation mix results are below.

Wind and Solar. RFF had the greatest expansion of clean resources in the near-term, growing generation from wind two and a half times 2021 historical levels by 2025, with solar increasing five times in the same short period. Renewables continued to grow in the RFF study through 2040, but expansion was significantly slowed after 2032 as clean energy credits from the IRA phase-out. The study with the next most renewable generation in the near-term was Energy Innovation with twice the generation from wind in 2025 compared to 2021 levels, and more than three times the solar. Renewable generation (and demand) grew the most in the Energy Innovation study, with renewables accounting for over 90 percent of total generation in 2040, or more than enough power from clean resources alone to meet demand in any previous year, in any of the studies.

The EPRI study had the most modest wind generation by 2030 with 627 terawatt hours (TWh), and the CAELP and NRDC studies resulted in the next lowest generation by wind for this year of 855 TWh and 890 TWh, respectively. However, these three studies continued to grow wind beyond 2030 as EPRI more than doubled generation from wind over the next five years for 1,368 TWh by 2035, and CAELP and NRDC had similar levels of wind generation this same year. EPRI, CAELP, and NRDC also projected more modest solar generation by 2030, with more significant growth by 2035. Conversely, Rhodium and NREL saw more generation from solar in 2030 at 861 and 902 TWh, respectively, than either CAELP or NRDC had by 2040.

Nuclear. As renewables grow, nuclear generation declined over time in all seven studies compared to historical 2021 levels. Each study retained nuclear generation through 2030 at levels fairly similar to today; however, after this time, the results varied significantly. EPRI, RFF, and NREL still retained most of the nuclear fleet in 2035, while the other studies all had significant retirements during these five years. In 2035, nuclear generation in the Rhodium study was 76 percent below 2021 levels, while it was 95 percent below in the Energy Innovation study for this same year. See the below discussion section on IRA incentives for more on nuclear retirements.

Fossil with CCS. Not all studies saw deployment of fossil-fired resources plus CCS. This was mainly driven by cost assumptions (see the below discussion sections on capital expenditures and CCS for more on this). However, of the five studies that saw coal with CCS come online during the study period, EPRI dispatched 127 TWh as early as 2025, while CAELP and NRDC dispatched greater amounts by 2030 and

2035. RFF and NREL also saw some coal with CCS come online, though much less than the other three studies by dispatching 34 and 87 TWh, respectively, by 2040. EPRI, NRDC, and NREL were the only studies to deploy gas with CCS, with NREL dispatching the most as it assumed retrofits with lower costs rather than more expensive new builds that the other two studies incorporated.

Fossil without CCS. Generation from fossil-fired resources without CCS also varied across the studies' IRA Scenarios. Most studies showed reduced generation from natural gas by 2025 compared to historical 2021 levels, except for CAELP and NRDC, which both deployed more natural gas through 2035. For example, both studies projected almost double the natural gas generation in 2030 at more than 1,600 TWh compared to Rhodium's 815 TWh from gas for the same year. RFF resulted in the largest drop compared to 2021 levels at a 61 percent reduction in generation from natural gas by 2025 for 613 TWh generated in this year, and then roughly maintained this lower level of gas through the rest of the study period. Again, this study significantly ramped up renewables in the early years and was therefore able to push out more fossil sooner compared to other studies. Rhodium, NREL, and Energy Innovation decreased gas-fired generation significantly in 2030 compared to earlier years. Energy Innovation continued to push out gas and coal from the grid mix over time, while Rhodium ramped up fossil-fired generation toward 2035 as renewables grew and nuclear declined. NREL assumed gas with CCS retrofits during this time and cut remaining generation from coal roughly in half from 166 TWh in 2030 to 79 TWh in 2040, resulting in the mild but continued decline of CO_2 emissions during this decade as seen in Figure 8, with emissions then rising toward 2040 as gas-fired generation ramped up while demand grew more rapidly in the later years of the study period from enhanced electrification.

Few studies provided a level of detail on generation or capacity from natural gas to understand what may have happened for baseload resources specifically, such as natural gas combined cycle facilities, as compared to peaking plants. However, Energy Innovation modeled in sufficient detail to observe that while generation from non-peaking plants generally decreased over time, peaking plants fired on more, likely due to the need to address reliability through variability management given increasingly large amounts of intermittent renewables on the grid in later years. Similar results were seen from NREL, however, as noted above, gas-fired generation from both baseload NGCC and combustion turbines increased after the 2030s to help meet demand growth in the later years of the study period.

Coal generation decreased in all studies over time due to both planned and economically driven retirements. Rhodium projected the least coal-fired generation in 2030 with 136 TWh, whereas RFF projected the most at 482 TWh, pushing out more gas than coal compared to other models for this year, which could be informed by cost assumptions. See the below discussion on cost assumptions for more detail. EPRI, NREL, CAELP, and NRDC reduced coal to around Rhodium's 2030 levels by 2035. In this year, Energy Innovation had almost eliminated coal, while Rhodium increased output to 203 TWh after declining until this year, though RFF was still higher than the rest with more than double Rhodium at 462 TWh.

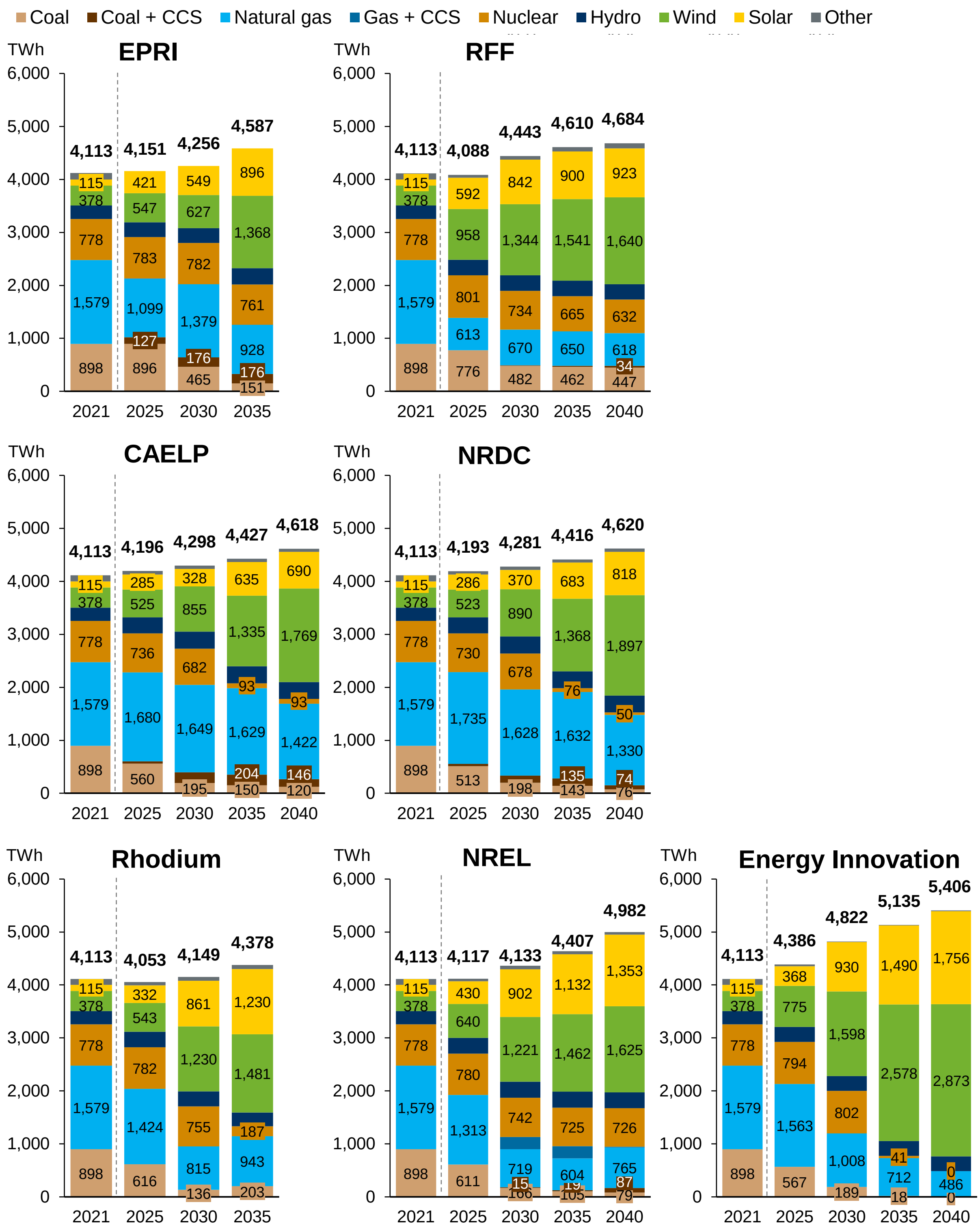

Figure 11: Projected Generation Mix from Available IRA Scenarios[6]

[6] Historical 2021 power sector net generation from EIA Electricity Data Browser. "Other" resource type varied by study and may include renewable and non-RE resources and oil. When reported separately, oil and gas steam was included in "Natural gas."

Capacity Mix

The reviewed studies all indicated that the IRA will transition the U.S. power sector away from fossil-fired generating resources and toward more clean technologies. Total installed capacity data was available from five studies and Figure 12 below shows that clean capacity such as wind and solar generally increased over time. Energy Innovation projected the greatest demand growth and generation from renewables, though there was not sufficient information available to compare installed capacities here, but it is likely that this study would show the highest renewable builds.

Solar and Wind. Of the studies with available installed capacity data, RFF projected the most renewable capacity available at the fastest rate, projecting 489 GW of solar available in 2030, or nearly eight times as much as was available in 2021. Comparatively, Rhodium and NREL each projected more than six times the amount of solar available in 2021, and CAELP and NRDC both projected more than two times. All models continued to build out more solar over time, but Rhodium nearly doubled its 2030 installed solar capacity in just five years for 715 GW installed in 2035. The next greatest installed solar capacity was from NREL with 601 GW installed by 2040. By 2035, Rhodium, NREL, and RFF all had more solar installed than wind while CAELP and NRDC consistently built more wind than solar through time.

Battery Storage. Rhodium and RFF showed the fastest renewable and battery storage capacity ramp up from now until 2030, but all studies continued growth, even after tax credits from the IRA were phased out as costs declined and these technologies become more cost-competitive in the models compared to traditional resources, such as new gas builds.

Nuclear. Reflective of the nuclear generation trends discussed above, capacity declined over time. By 2030, Rhodium and NREL retired the least at about five percent capacity lost compared to 2021 levels of 100 GW, while CAELP and NRDC retired the most by this year, leaving 85 GW on the system, or 15 percent below 2021 capacity. Significant retirements happened in most studies between 2030 and 2035. This drop off in nuclear generation in this short time frame in most studies was likely due to capturing the expiration of the IRA nuclear tax credits. See the below discussion section on IRA incentives for more on nuclear retirements. Of the studies with available installed capacity data, CAELP showed the least remaining on the system by 2035 with 12 GW or 91 percent less than was available in 2021. Conversely, NREL's modeling did not result in nuclear drop off in the 2030s as most other studies did, and still had 94 GW of nuclear on the system in 2040, or only 6 GW of nuclear retired during the whole study period compared to 2021.

Natural Gas. Available natural gas capacity varied. Rhodium, NRDC, and CAELP all saw growth in installed natural gas across the modeled time horizon. Rhodium increased the most starting from the most in 2025 at 539 GW and increasing by 31 percent in ten years to 706 GW in 2035. CAELP and NRDC each slowly grew gas capacity over time, resulting in more than 470 GW installed in 2040. Conversely, RFF maintained roughly the same level of gas capacity throughout the study period at roughly 462 GW, roughly 17 percent less capacity compared to historical 2021 levels. However, as can be seen in Figure 11 above, natural gas and oil/gas steam units (included in 'Other') were dispatched in modeling significantly less compared to 2021 generation levels. With respect to gas with CCS, NREL, EPRI, and NRDC deployed this resource to varying degrees. NREL dispatched the most and assumed retrofits with lower costs compared to more expensive new builds. Generally, the studies provided limited information to describe the dynamics of gas with CCS much further. See the discussion section below for more on CCS cost assumptions and model dynamics.

Coal. Coal capacity declined in all studies due to both announced and economic retirements. Similar to the nuclear results, NREL also retained the most coal capacity on the system in the later years of the study period, with 144 GW of coal still on the system in 2035. However, compared to the other studies, NREL appeared to dispatch the remaining coal fleet less, as can be seen in Figure 11 as lower levels of generation from coal in later years compared to the other four studies also included in Figure 12.

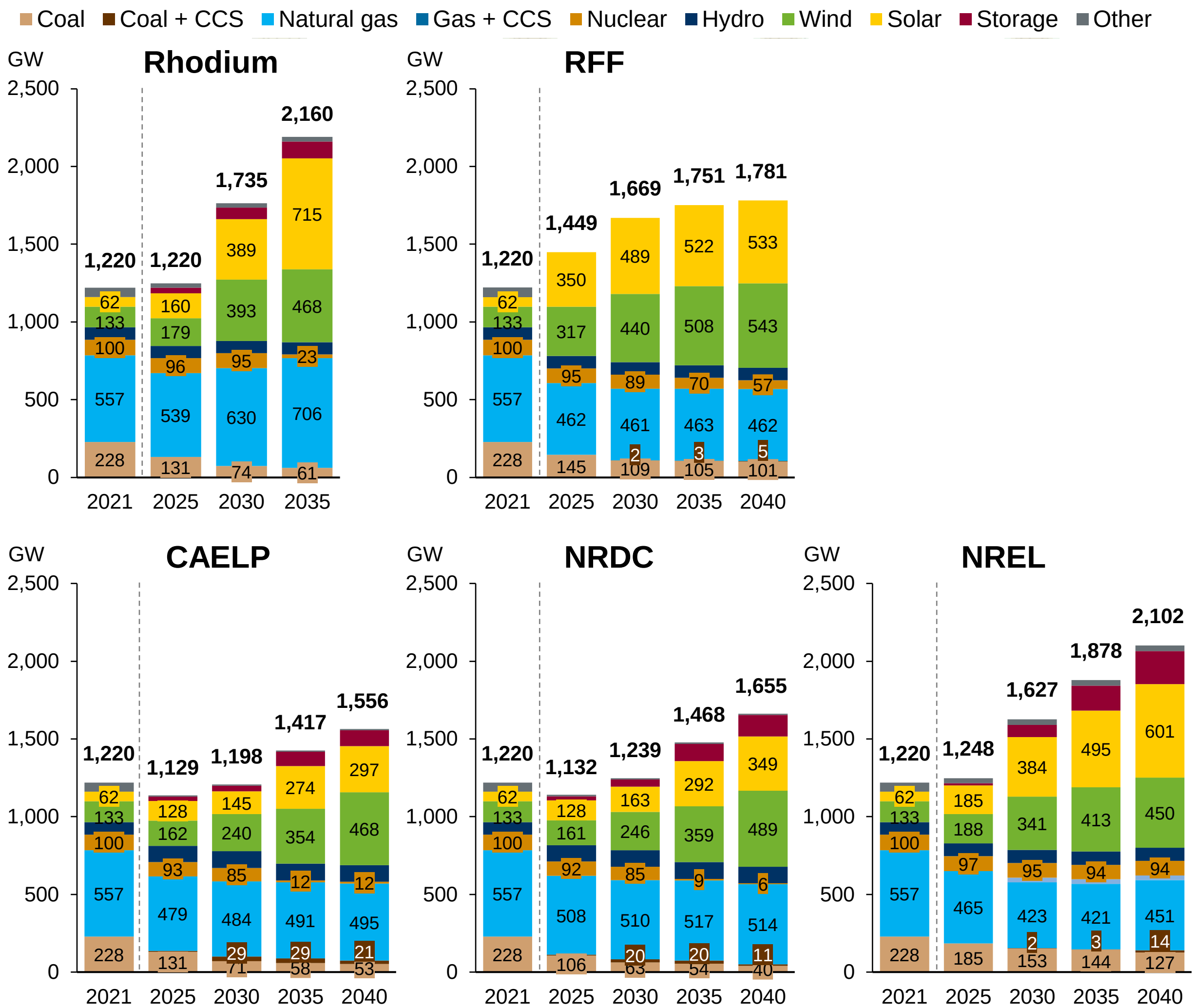

Figure 12: Projected Installed Capacity from Available IRA Scenarios[7]

Capacity Builds

Some studies provided data on capacity builds, which is different than total installed capacity discussed above. Figure 13 below compares capacity builds for different technology types in the near-term for studies with available comparable data. Capacity builds during model years that may best capture the IRA clean energy incentives (i.e., model years 2023 through 2030) varied widely across studies with available data on builds. This depended heavily on the economics of the energy options and the model's functionality. As previously described, RFF built significant clean capacity in the early years of the study compared to most others. Energy Innovation built more capacity compared to the other studies as it also assumed the greatest demand growth. Conversely, CAELP and NRDC consistently built more modest amounts of capacity of any technology compared to the other studies. Broadly, studies with greater renewable capacity builds also showed greater emissions reductions (See Figure 8). For studies with

[7] Historical 2021 nameplate capacity from EIA Table 4.3; RFF also reports in nameplate capacity; though CAELP, NRDC, and Rhodium report summer capacity. "Other" resource type varies by study and may include renewable and non-RE resources and oil. When reported separately, oil and gas steam is included in "Natural gas".

available data on capacity builds and that modeled coal with CCS, most saw this new or retrofitted capacity coming online before and into 2030, though ramp-up generally continued through 2035 (not shown in Figure 13). Figure 13 shows new coal with CCS capacity built in the RFF study through 2030, while CAELP and NRDC retrofitted some existing capacity with CCS during this same time. Of these early analyses that captured incentives from the IRA, only NREL retrofitted notable amounts of gas-fired capacity with CCS at 30 GW by 2030 (not show in Figure 13).

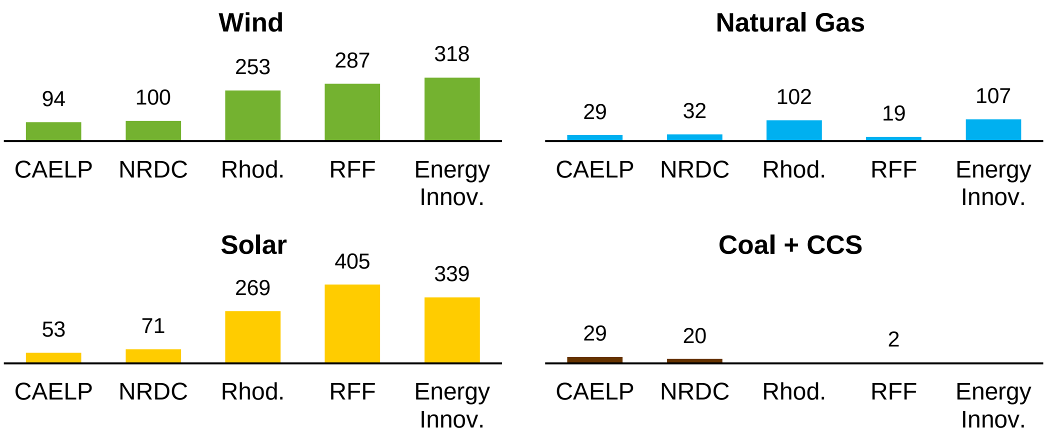

Figure 13: Estimated Capacity Builds (GW) for Select Resources During 2023 through 2030

Capacity Retirements

Some studies provided data on capacity builds, which is different than total installed capacity discussed above.

Coal

Across the available data, most studies retired significant amounts of coal capacity before 2030 as already announced retirements were implemented and credits from the IRA for clean resources as well as projected gas prices made other technologies more economically attractive compared to maintaining the existing coal fleet. Figure 14 shows that CAELP, NRDC, and Rhodium retired similar amounts of coal capacity: around 110 GW or so cumulatively from 2023 to 2030, and less than 15 GW each from 2031 to 2035. Energy Innovation retired the most coal in the early years with 145 GW retired from 2023 to 2030, and another 52 GW retired across the following five years. In most other studies, retirements slowed post-2030 to 2035 and beyond. This did not account for coal with CCS retrofits, which in some studies such as CAELP and NRDC, helped to keep additional existing coal capacity online longer.

The Energy Innovation report described the difference in its enhanced coal capacity retirements compared to other studies as primarily due to differences in how it incorporated federal financial assistance programs that can help replace fossil-fired resources with new clean energy. Additionally, as is shown in Figure 5 of the intra-model comparison above, this study's No IRA Scenario already found coal to be less economic with less generation and more retirements compared to other studies' No IRA baselines.[8]

[8] This review of available studies was conducted at the beginning of 2023. The Energy Innovation numbers reported here are its Moderate IRA Implementation scenario, but the range of coal capacity retirements across its Low, Moderate, and High scenarios is significant. Since the publication of this report, Energy Innovation has begun updating power sector representation in its model and may find reduced coal retirements in future analyses.

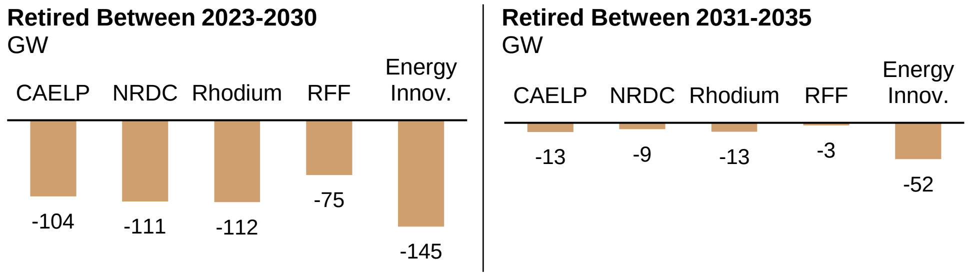

Figure 14: Estimated Coal Capacity Retirements During Select Time Periods

Nuclear

Figures 4, 12, and 15 show that most studies maintained much of the existing nuclear fleet through 2030. However, especially after 2032, nuclear capacity dropped drastically in a short time. This is likely an artifact in the models of how the IRA incentives were functioning, and assumptions on the phase-out of the nuclear tax credit in 2032 were likely tied to the significant capacity decreased between 2031 and 2035 in almost all the studies reviewed. It is unlikely that the 73 to 94 GW of nuclear generation retired in these five years shown in four studies in Figure 15 would occur at this pace in reality. See the below discussion section on IRA incentives for more on nuclear retirements.

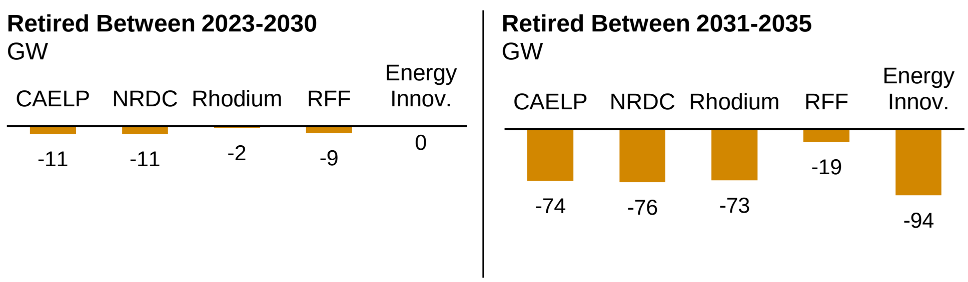

Figure 15: Estimated Nuclear Capacity Retirements During Select Time Periods

Financial Impacts

The selected studies did not report nor necessarily model comparable cost information as a result of the IRA. In some cases, data points such as system costs or capital expenditures were not modeled. In most cases, a levelized cost of energy output was unavailable or would require post-processing to analyze. Additionally, any available resulting values would need to be caveated and would not be directly comparable across studies. Tax dollar expenditures from analyzing the IRA were also not detailed in most modeling nor discussed as part of written results reports.

Some studies provided some level of retail power price impacts (i.e., CAELP, NRDC, RFF, and Energy Innovation). These prices were calculated in different ways, incorporating different data, and reported for different geographies such that the results were not directly comparable across studies. RFF found that by 2032, national average power prices for the central IRA Scenario could be about five percent lower than today. CAELP and NRDC modeled state-level retail rates and found prices to remain relatively flat across the modeled time horizon. However, some states, such as those in the Northeast and with clean energy targets already on the books, saw declining rates over time compared to the 2023 model year.

DISCUSSION

Cost Assumptions

Fuel prices and costs for different technologies were mostly input assumptions to these models. Most of the studies reviewed used differing assumptions as well as incorporated different costs for different areas of the country. The following discussion was based on best-available comparable information and includes representative data for the national level. Broadly, the models made decisions based on input cost assumptions and the combination of key variables such as natural gas prices (Figure 17) and the costs to build different technology types (Figure 18), which drove much of the resulting grid mix and emissions discussed above. Variations on these assumptions (e.g., higher gas prices, lower costs for renewables, or vice versa) would give different results, which highlights the importance of scenario analysis, but also the uncertainty of it.

At a high level, Figures 8 and 16 indicate that studies that assumed higher natural gas prices coupled with lower renewable technology costs (e.g., NREL and Energy Innovation) resulted in a grid mix that produced lower levels of emissions across the modeled time horizon, compared to studies that assumed lower gas prices and slightly higher new technology costs (e.g., CAELP and NRDC). However, this is a simplification of trends over time, and was not true of all studies; for example, see more on EPRI assumptions and results discussed further below, which did not follow this correlation.

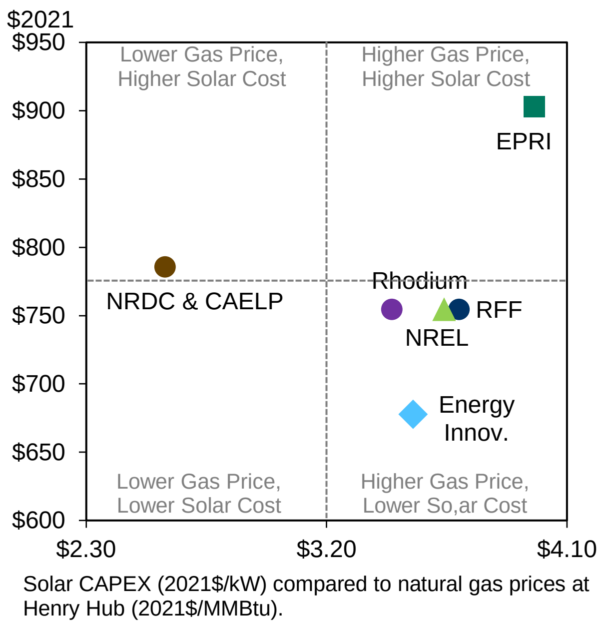

Figure 16: Illustrative Matrix of Cost Assumptions in 2035

Natural gas price projections at Henry Hub are shown in Figure 17. CAELP and NRDC assumed some of the lowest gas prices across the time horizon shown, using assumptions for IPM from the Gas Markets Module. Energy Innovation, Rhodium, and NREL each based natural gas price projections to some degree on the U.S. Energy Information Administration's Annual Energy Outlook (AEO) 2022. Energy Innovation relied on AEO's Low Economic Growth case while the others used the 2022 reference case to inform gas prices.[9] RFF modeled gas prices from the AEO 2021 reference case, reflecting lower prices

[9] Most organizations conducted these modeling studies in 2022 and used available EIA AEO data as of that time, which did not include analysis of the IRA. Since then, EIA AEO 2023 has been published and did include analysis of some IRA provisions but was not available in time to include as part of this review.

compared to other studies through 2025, then increased through the 2030s to be slightly higher compared to most other studies.

As previously discussed, RFF rapidly deployed renewables in the near-term compared to other studies and saw a steep drop in CO_2 emissions in the later 2020s in response. However, before 2025, RFF resulted in some of the highest CO_2 emissions for the power sector (see Figure 8), which may be reflective of low gas prices shown in Figure 17 leading to greater dispatch of the gas-fired fleet during a time when costs for clean technologies may need to decline further before being deployed in greater amounts. By 2030, RFF's assumed gas prices increased and power sector emissions leveled off toward 2040. This result, combined with the generation seen in Figure 11 (showing RFF had more coal generation after 2030 than others), indicated continued coal dispatch may be contributing to sustained emissions levels. Rhodium may be a fair comparator as both studies assumed the same clean energy costs (Figure 18), but Rhodium assumed lower gas prices than RFF in the 2030s (Figure 17) and had lower emissions during this time (Figure 8). This could indicate that RFF's higher gas prices could correlate with continued coal dispatch and therefore minimal emissions reductions post-2030.

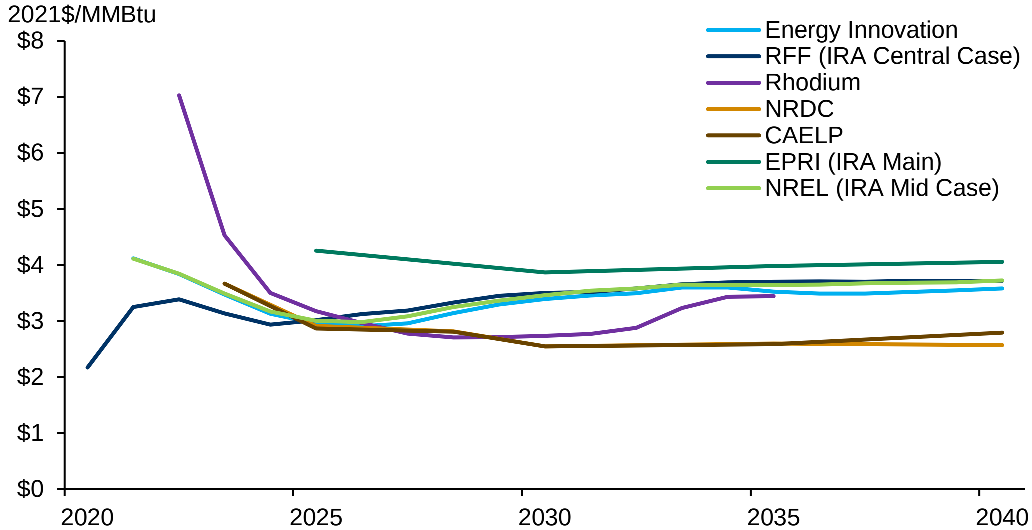

Figure 17: Henry Hub Natural Gas Price Inputs

Figure 18 below includes available information on capital expenditure assumptions for select technologies across different studies for the 2030 model year. RFF, Rhodium, and NREL all leveraged available cost projections for utility-scale solar PV, onshore wind, offshore wind, and battery storage from the NREL ATB 2022 mid case. CAELP and NRDC applied costs for renewables and battery storage from the NREL ATB 2021 mid case, therefore assuming slightly higher costs for renewables and slightly lower costs for battery storage compared to the studies that used the 2022 dataset. EPRI and Energy Innovation developed their own cost projections for all technologies, though renewables and battery storage costs were generally comparable across all studies. However, Energy Innovation assumed lower costs for renewables, helping to support the significant wind and solar build out seen in this study compared to the others. For example, they assumed the lowest cost for offshore wind at $1,882 per kilowatt (kW).

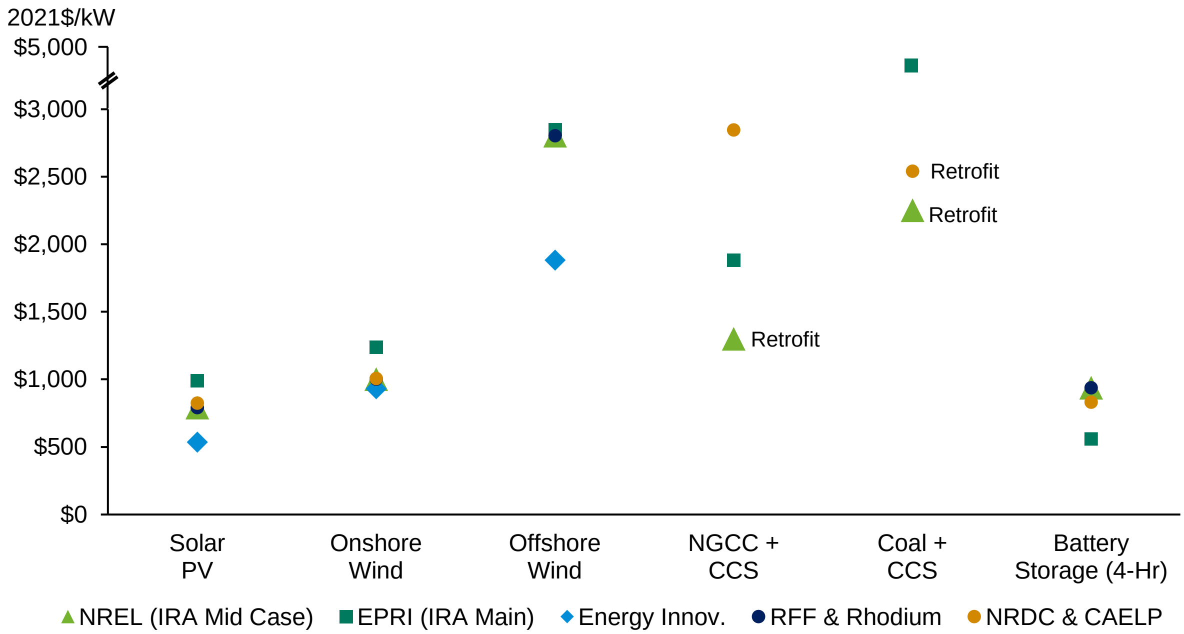

Figure 18: Assumed Capital Expenditure in 2030 for Select Technologies

Where sufficient information was available to compare, assumed capital expenditures for fossil plus CCS varied across the studies. NRDC assumed the highest cost for new NGCC facilities with CCS at $2,845/kW, where EPRI assumed $1,880/kW. NREL assumed retrofits for an existing facility would cost $1,300/kW in 2030 and deployed significantly more CCS at NGCC facilities compared to NRDC and EPRI. Conversely, EPRI assumed the highest costs for new coal with CCS at $4,770/kW in 2030 and deployed more of this technology than most other studies. RFF also likely assumed a similar cost for new coal with CCS (not enough information to include in Figure 18) but did not deploy much until later in the study period after costs declined further. CAELP, NRDC, and NREL each assumed CCS as retrofits for existing coal facilities, with costs roughly half EPRI's assumption for coal with CCS new builds.

EPRI developed its cost assumptions in-house and assumed higher natural gas prices in most years through 2040 compared to the other studies. This study also showed higher CO_2 emissions compared to the other studies through 2035 (see Figure 8). This may indicate a coal-versus-gas tradeoff, as higher gas prices may have enabled existing coal facilities to seem more economic in comparison, resulting in higher CO_2 emissions (Figure 8) and more coal generation throughout the time period compared to other studies (Figure 11). As can be seen in Figure 18, EPRI also assumed slightly higher costs for renewables and battery storage compared to other studies, which could have further supported greater dispatch of fossil resources, especially through 2030, and could help explain EPRI's higher coal with CCS builds and lower clean energy builds in the 2030s compared to some of the other studies.

Operational Assumptions and Capacity Factors

Differences in operational assumptions also drove some of the results across studies. For example, while dispatch is largely a function of a model selecting the most economic resources, there are also bounds around this. Most studies assumed slightly lower costs for solar compared to onshore wind (see Figure 18). However, CAELP and NRDC had more wind capacity than solar throughout time, which was not true for all studies. Calculated capacity factors for the 2035 model year are shown for select resource types and studies in Figure 19. IPM was used by both CAELP and NRDC and may have assumed bounds with higher allowable maximum capacity factors for wind compared to some other studies, which may have helped wind become more economic in this model compared to its economics and ultimate builds and dispatch in other models. This could imply that all-in, there may be marginal differences between wind and solar and drivers; for what gets built may depend on capital costs, as well as anticipated operations, which are extremely location-dependent.

Relatedly, Figure 19 shows high-capacity factors for studies that deployed fossil with CCS, which not all did. This may imply that if the economics work for CCS retrofits or new builds at all, the facilities may then operate roughly double the time compared to their conventional counterparts despite higher capital costs. This is because the operational economics would be favorable, or the facilities may run more to recuperate the installation costs. See below section for more on CCS results.

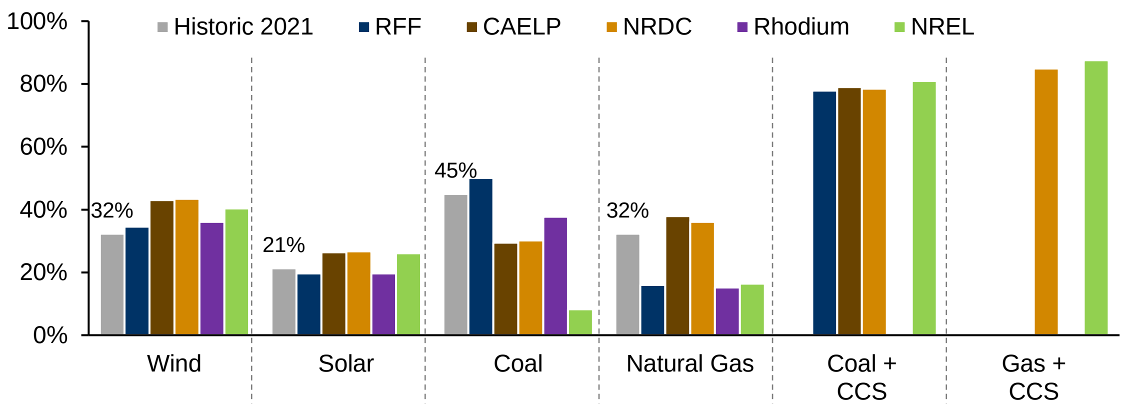

Figure 19: Calculated Capacity Factors for Select Resources in 2035

IRA Incentives

This section discusses how the IRA incentives impacted study results. See Appendix A for additional information on how select provisions from the IRA were incorporated in the models for some studies where information was available.

Carbon Capture and Storage (CCS)

The modeling approaches and available cost information made it difficult to compare the studies' deployment of CCS directly, but in general, credits from the IRA could result in CCS being a technology that could support emissions reductions in the near future.

The IRA incentives for CCS are large, especially for the studies that assumed lower costs for CCS retrofits as compared to more expensive new builds, resulting in incentives covering much of the costs for CCS. NREL, CAELP, and NRDC assumed any deployment of coal with CCS would be as retrofits. Two studies, RFF and EPRI, assumed any coal with CCS deployment would be new builds. Only NREL assumed gas (NGCC) with CCS as retrofits, while five (RFF, Rhodium, CAELP, NRDC, and EPRI) assumed any gas with CCS uptake would be new builds.

NREL dispatched far and away the most NGCC with CCS in the 2030s (see Figure 11) and also assumed the lowest cost for its retrofits (see Figure 18). The three studies that assumed coal with CCS as retrofits (NREL, CAELP, and NRDC) also saw greater deployment compared to studies that assumed new builds at higher costs (RFF and EPRI). Energy Innovation relied on exogenous modeling from ReEDS to inform some of their analysis of the IRA, and those results did not show any coal or gas with CCS, which is why none was deployed in their study, implying the analysis did not find resources with CCS to be economic compared to other options.

Some studies, such as NREL and EPRI, began deployment of fossil plus CCS as early as 2025. Ultimately, deployment and utilization of CCS will depend on actual technology costs and other policies or regulations at the state and federal level. These uncertainties could change the competitive landscape of different technologies in the future, resulting in a reality that could look quite different than model results. Various modelers have indicated the intention to conduct additional analyses with more information on expected costs and performance of CCS, which may lead to refinements of the technology's representation in models as well as results in studies published after the time of this review.

Nuclear

An IRA provision that significantly impacted model results is the nuclear PTC, which phases out in 2032. Most models found this policy to help keep nuclear online until this time, at which point significant amounts of capacity retire when nuclear was no longer supported by as favorable economics. In many studies, the span of a few model years in the 2030s reflected the loss of more than 70 GW of nuclear capacity (see Figure 15 above). What filled in to meet demand depended on the study and assumptions. For example, CAELP and NRDC saw increasing wind and solar capacity built in a short time, as well as a jump in battery storage and coal with CCS retrofits in the 2035 model year. These technologies are all supported by other clean energy incentives from the IRA that are still available into the late 2030s.

Clean Energy

Some incentives from the IRA are structured to pay higher amounts based on project-specific factors such as location in an 'energy community,' payment of prevailing wages, and inclusion of domestic content. Generally, the studies applied the maximum available credit for clean energy resources from the IRA as a simplifying assumption. However, RFF performed additional in-house analyses to try to estimate the true credit value, such as only applying additional value in areas of a state identified as potentially meeting the definition of energy communities. This moderated assumption compared to the other studies still provided meaningful incentive for clean resources in the Haiku model, as RFF saw some of the quickest and most robust deployment of wind and solar across the rest of the 2020s, while other studies took more time to ramp up renewables.

Rhodium, NREL, CAELP, and NRDC captured the IRA provision ending clean energy incentives once power sector CO_2 emissions declined 75 percent below 2022 levels, which was achieved in the first two studies in the early 2030s, but was not achieved in the latter two studies. This was a result of CAELP and NRDC not phasing out the clean energy incentives from the IRA during the modeled time horizon shown. All other studies took a simplifying assumption of phasing out these incentives beginning in 2032 per the secondary IRA provision, rather than based on timing of achieved emissions reductions. After the early 2030s in the Rhodium study, the pace of renewables build-out slowed, nuclear credits also expired, and significant nuclear capacity retired.

Relatedly, grid operators, such as PJM, are currently considering process refinements to address the pace of new entries as there are increasing reliability concerns, especially in the face of outages due to severe weather as well as shrinking reserve margins due to demand growth. The IRA will almost certainly increase the share of clean resources and likely reduce emissions compared to today's levels; but transformational change to the power sector, especially in the long-term, is likely to only occur with continued technology and resource cost changes and other policy and process refinements.

Feasibility of Results

Various feasibility constraints might impact the speed and scale of clean energy deployment, especially the labor and supply chain constraints in constructing new plants and siting and permitting delays for building new transmission.

Annual Builds and Retirements

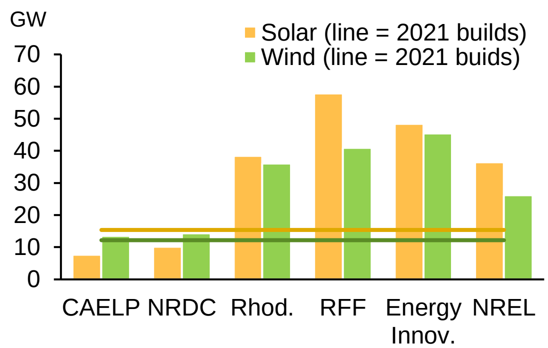

Figure 20: Estimated Average Annual Renewable Builds, 2023-2030

It was consistently found across the studies that the IRA clean energy incentives such as the ITC and PTC may result in an increase in year over year renewables deployment compared to historical capacity expansion (see Figure 20). Some studies, such as CAELP and NRDC, suggested more modest average annual builds from 2023 to 2030 compared to the results of other studies across the same time frame, and even compared to recent builds seen during 2021, which saw over 15 GW of solar and 12 GW of wind added.[10] Alternatively, Rhodium, Energy Innovation, and RFF all had much larger average annual builds projected into the next decade compared to what has been achieved historically. Particularly, RFF's average annual solar builds and Energy Innovation's annual wind builds projected for this time frame were almost four times what was deployed in 2021, which poses the question as to whether deploying that much clean energy each year or through the end of the decade is feasible. The IRA may drive greater year over year deployment of renewables compared to historical builds, but this could also be constrained by real-world challenges such as slow-moving permitting queues; increasing costs due to potential supply chain constraints; and related transmission availability, needs, and costs.

Some studies attempted to reflect grid mix transformation constraints through a cost-adder built into the model. For example, CAELP and NRDC modeling with IPM included this parameter to limit builds informed by maximum historical deployment of various energy sources by imposing incremental cost additions for new builds above and beyond that historical limit. This parameter may be included to reflect labor and supply constraints that may come with the increase in deployment compared to what has been achieved historically. This cost addition mechanism not only increases capital expense costs for each technology, especially at higher build levels, but may also impact the model's choices for capacity mix into the future if clean energy becomes less economic to deploy compared to fossil-fired resources, such as new natural gas or gas and coal plus CCS retrofits. Compared to the other models, the notably less solar and wind deployed in the CAELP and NRDC studies between 2023 and 2030 was likely a result of this cost-adder mechanism, making these resources less economic.

Related to the feasibility of new builds is the level of retirements, particularly the drop off of nuclear capacity seen across all studies after the IRA nuclear credit expires in 2032. Nuclear phase-out may occur differently a decade from now than as reflected in these cost-optimized models. Economics and technological developments will have to be assessed at the time, and some nuclear facilities may seek license extensions. Additionally, grid reliability will be a key consideration in various states to determine if and how nuclear capacity is retired Therefore, the retirements seen across the studies within a short time frame post-2030 may be unlikely to occur outside the models.

[10] EIA, "Renewables account for most new U.S. electricity generating capacity in 2021", January 11, 2021, https://www.eia.gov/todayinenergy/detail.php?id=46416#.

Transmission Builds

The current and planned transmission system is another key consideration as it relates to the shift in technology types and energy deployment. Each of the models considered, or did not consider, transmission restraints or expansion in a unique way. For example, Energy Innovation's model incorporated anticipated transmission build out from the IRA and rolled the associated costs into the delivered power prices; however, this was not directly linked to the accelerated build out of renewable energies. Similarly, RFF's modeling did not capture transmission builds that would be necessary to support the significant renewable builds seen, nor were costs for building this new transmission included. The Haiku model instead imposed a fixed maximum transmission value between contiguous states, based on existing and planned transmission lines. CAELP and NRDC incorporated known plans for transmission builds through 2050, as did other studies, but these two also included endogenous interregional transmission builds subject to cost and locational limitations. These studies did not attempt to robustly account for increased electrification that may be brought on by incentives from the IRA that may impact demand.

Although each model incorporated transmission expansion and restraints differently, it is important to note that transmission expansion, or lack thereof, has significant real-life impacts that should be considered on the path to electrification and decarbonization.

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APPENDIX A IRA ASSUMPTIONS FOR SELECT STUDIES

The following tables summarize key assumptions regarding implementation of the IRA, as captured in the models, for select studies where sufficient information was available to describe.

Table 1: Supply-Side IRA Assumptions

IRA Section	Description	Rhodium Group	Energy Innovation	NREL	Resources for the Future	NRDC	CAELP
13101 & 13701	Credit for Electricity Produced from Certain Renewable Resources (PTC)	Extension and modification of existing PTC and ITC, plus new clean electricity production and investment credits	Credits start 2023 and available at full through 2032.	$26/megawatt hours (MWh) for 10 years (2022 dollars) plus a bonus credit that starts at $1.3/MWh and increases to $2.6/MWh by 2028	Model did not reach emissions reduction level so IRA was never phased out. $25/MWh (in 2020$) for Wind, Solar, with domestic bonus (+$2.50/MWh) phase in @$0.50/yr 2026 to 2030 and energy community bonus (+$2.50/MWh) in each state proportional to share of counties that would qualify; i.e., not applying max credit value. All credits received 3% cut (to tax equity investors and not to subsidize the clean resource).	PTC for wind at 1.5¢/kilowatt hour (kWh) (2002$) through 2024; extension for clean resources at 1.5¢/kWh (1992$) from 2025 until the later of: 2032 or power sector emissions 75% below 2022 levels; then phase down over 3 years (100%, 75%, 50%)	
13102 & 13702	Energy Credit (ITC)			30%, plus a bonus credit that starts at an additional 5% and increases to 10% by 2028 (for totals of 35% and 40% respectively)	30% with 10% domestic bonus phase in @2%/year 2025 to 2030 and 10% energy community bonus in each state per above method. 3% of total ITC went to tax equity investors rather than to subsidize clean resources	ITC of 30% for solar through 2024; 30% for storage with same phase down as above for new	
13103	Increase in Energy Credit for Solar and Wind Facilities Placed in Service in Connection with Low-Income Communities	Unclear from available info	Added 1.8 gigawatts (GW) distributed solar per year (which is cap in the bill)	Assumed projects will, on average, capture one of the bonus credits (ITC at 20% for up to 1.8 GW/yr. for solar or PTC at $5.2/MWh) by 2028.	Limited public information available	Not Modeled	

IRA Section	Description	Rhodium Group	Energy Innovation	NREL	Resources for the Future	NRDC	CAELP
13104	Credit for Carbon Oxide Sequestration	Extension and modification of carbon capture tax credits included	Informed by Rhodium's analysis; credits got full value through 2032; did not assume any carbon capture and storage (CCS) in power sector	$85 per metric ton of CO_2 for 12 years for fossil-CCS and bioenergy-CCS, and $180 per metric ton of CO_2 for 12 years for direct air capture; nominal through 2026 and inflation adjusted after that. No dynamic phaseout, scheduled to end at the end of 2032.	$65/ton for enhanced oil recovery and $85/ton for saline storage (in 2025$)	45Q at $85/metric ton (MT) for geologic storage and $60/MT for enhanced oil recovery (EOR) through 2032; available for coal and gas. Did not include % capture requirement.	
13105	Nuclear Power Production Credit	New credit included	PTC and no economic retirements allowed through 2032; for weighted average credit determined between $5.10 to $9.50 per MWh needed between 2024 and 2032	$15/MWh (2022$), reduced if the market value of the electricity produced by the generator exceeds $25/MWh. Existing nuclear generators are not subject to economic retirement through 2032. No dynamic credit phaseout, scheduled to end at the end of 2032.	Not modeled directly; fleet assumed to maintain business-as-usual/baseline levels to capture potential effect of incentive	45U for merchant nuclear at 1.5 ¢/KWh (2022$) through 2032, unless wholesale revenue is >2.5 ¢/KWh, then the credit is reduced by 80%	
13204	Clean Hydrogen	New production tax credit captured for industry and transportation	Different scenarios assume different levels of displacement of gray hydrogen with electrolytic	Not explicitly represented	Limited public information available	Not Modeled	

Table 2: Demand-Side IRA Assumptions

IRA Section	Description	Rhodium Group	Energy Innovation	NREL	Resources for the Future	NRDC	CAELP
13301	Buildings: Nonbusiness Energy Property credit	Extension and modification included	ACEEE research on Heat Pumps deployed, rebates adjusted for IRA credit; then adjusted demand in model based on EIA AEO 2022 gas consumption per unit and average efficiency for electricity demand	Modified version of a demand trajectory from NREL's Electrification Futures study was used to represent slightly greater electrification due to the IRA, with more modeling on this intended to be conducted in the future	Not Modeled	Not Modeled	
13302	Buildings: Residential clean energy credit	Extension and modification included	ACEEE research on gas & electricity savings; per RFF research, added 1 GW distrib. solar per year				
13303	Buildings: Energy efficient commercial building deduction	Extension and modification included	ACEEE research on gas & electricity savings				
13401	Transport: Clean vehicle credit	New credit included	Calculated weighted average credit available each year				
13403	Transport: Commercial clean vehicle credit	Unclear from available info	Credit for new truck sales using weighted average; credit also applied to buses, excluding government purchases				
13404	Transport: Alternative refueling property credit	Unclear from available info	Calculated chargers deployed; 80% of funding for public chargers				
50121	Buildings: Home energy efficiency credit	Extension and modification included	ACEEE research on gas & electricity savings, adjusted so spending occurs 2023-2031				
50122	Buildings: High efficiency home rebate program	New rebate included	ACEEE research on gas & electricity savings, adjusted so spending occurs 2023-2031				

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