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Projecting Electricity-Sector Investments Under the Inflation Reduction Act: New Cost Assumptions and Interactions with EPA's Greenhouse Gas Proposal

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Summary

Decarbonizing the electricity sector will be an essential component of any future climate policy. Two recent developments—the Inflation Reduction Act (IRA) legislation of August 2022 and the US Environmental Protection Agency's (EPA) proposed Greenhouse Gas Standards and Guidelines of May 2023—address the zero-carbon and fossil fuel emission sides of the problem, respectively. This paper revisits the IRA in the context of recent cost increases for financing in general and for construction of renewables in particular to explore how these changes affect fulfillment of the legislation's goals. The analysis also looks at interactions between the IRA and EPA greenhouse gas (GHG) proposals to see how the system may respond and where the two approaches might put the electricity sector on an eventual path to decarbonization.

The IRA took a large step toward decarbonization through its monetary incentives for renewable generation, along with many other features such as support for battery-powered electric vehicles. It also included tax credits to begin the process of establishing fully functioning markets for carbon dioxide capture and storage and the production of clean hydrogen as a low-carbon fuel source. The recent EPA GHG proposal builds on these potential emerging markets and uses them to address fossil fuel emissions. This report first analyzes regional investment decisions for renewables resulting from the IRA under a variety of future conditions, and contrasts outcomes based on current costs to those assumed in past analyses. The modeling then examines how the EPA GHG proposal might interact with a renewables-intensive system arising from IRA. We conclude that both policies will substantially reduce emissions from today's levels, regardless of recent increases in technology costs. However, among other factors, the availability of renewables siting and permitting can have large implications for emissions, as can the relative prices of natural gas and hydrogen.

EXECUTIVE SUMMARY

In April 2021, President Biden announced a new greenhouse gas (GHG) emissions target for the United States. The target aims for a 50% to 52% reduction from 2005 levels by 2030 as a building block on the path to carbon dioxide (CO_2) emissions–free electricity by 2035 and net-zero emissions for the economy as a whole by 2050. The Inflation Reduction Act (IRA) of August 2022 represented a major step along this path through its encouragement of clean energy, support for nascent technologies, and improvements in US manufacturing and supply chains, alongside pursuing public health and environmental justice benefits and directing investments toward underserved communities. So far, the evidence has suggested that the energy tax credits for renewable energy, nuclear power, electric vehicles, and potentially clean hydrogen fuel may be spurring significant investments in clean energy (American Clean Power 2023). However, the costs of building new wind and solar installations have recently increased, along with interest rates and financing costs, which may affect future investment decisions.

Initial analyses of the IRA suggested that economy-wide emissions could reach roughly 32% to 40% below 2005 levels by 2030 as the result of the clean energy incentives.[1] Many of these reductions were expected to occur in electricity generation, which is not surprising given that the sector is generally considered a cost-effective source of reductions. This sector has also already undergone a revolution in the past decade as declines in costs of established renewable technologies have made them competitive with fossil fuel and nuclear generation. Recent economic developments, however, may potentially offset some of the anticipated benefits of the IRA. Interest rates have risen substantially, which can disproportionately disadvantage capital-intensive renewables compared to fossil fuel technologies (IEA et al. 2020), all else being equal. Construction costs have also increased relative to those anticipated a year ago (NREL 2023a). This combination of factors led the investment firm Lazard (2023) to estimate that the levelized cost of electricity (LCOE) from onshore wind and solar photovoltaics (PVs) rose by 39% and 58%, respectively, between 2021 and 2023.[2] Given that the IRA includes—among other provisions—investment tax credits for renewables of around 30% (if certain labor requirements are met), it is an open question how investments in renewables may react to the new economic conditions and thus how the industry may respond to future policies.

Building on the anticipated benefits of IRA, in May 2023 the US EPA proposed—for comment—new GHG emission standards for fossil fuel power plants, along with controls on existing units. These proposed "best system of emissions reduction" (BSER) standards focus on the emerging technologies of carbon capture and storage (CCS) and clean hydrogen—two of the technologies supported by tax credits under the IRA. After an initial phase of the program mandating use of efficient turbines, the next phases of the performance standards for GHG lay out two pathways for existing and new fossil fuel plants, focusing on baseload units that operate for significant fractions of the year and thus contribute the most to sector emissions.

[1] See, for example, Mahajan et al. (2022); Bistline et al. (2023); Larsen et al. (2022); Jenkins et al. (2022); and Roy et al. (2022).

[2] These LCOE costs are, however, still below those of new natural gas plants.

Broadly, the EPA proposal for reduced GHG emissions suggests, first, coal-fired plants that anticipate operating for the foreseeable future would have to install CCS to capture 90% of their CO_2 emissions by 2030. Coal units retiring prior to 2040 could cofire with 40% natural gas in lieu of adding CCS, while plants retiring prior to 2032 would not need to take action. Proposed rules for existing and new stationary combustion turbines are a bit more involved, but can be broadly summarized as baseload combined cycle units either adopting CCS by 2035 or choosing to cofire with 30% clean hydrogen by 2032 and 96% hydrogen by 2038 (both percentages are by volume). Smaller new units, or those new units operating in intermediate load categories (20% to 50% utilization), would meet an emissions limitation that reflects cofiring with clean hydrogen (30% by 2032); peaking units below 20% utilization ("low load") would use lower-emitting fuels (natural gas and distillate oil) – see Figure 14 in this report for details of these criteria. For most gas units, aside from new combined cycle plants, reducing utilization rates to drop out of the "baseload" (50%) category is also a potential compliance strategy (EPA 2023a).

This analysis first revisits the IRA, focusing on electricity generation and using an array of assumptions about future market conditions and policy definitions. The goal for this part of the modeling is to look behind the broad estimates of emissions reductions and see what is driving the findings and what it will take, under projected market conditions, to achieve the anticipated reductions found in other IRA analyses. By looking at the influence of various factors individually, it is possible to evaluate which forecast assumptions have the largest impact on results. As part of this evaluation, renewables cost estimates from both the NREL Annual Technology Baseline (ATB) for 2022 and 2023 are used. In forecasts for the year 2030, capital costs for onshore wind have increased by 14% in the ATB 2023 over the ATB 2022, with potential implications for turbine-manufacturing levels, while solar PV and battery storage costs are up around 30%, potentially offsetting at least some portion of the benefits from the IRA tax credits.[3] Interest rates and the cost of capital have also increased by several percentage points. Following this exploration, an investigation of EPA's GHG proposal is layered on top of the IRA to examine their potential interactions.

The analysis is conducted using the Dynamic Integrated Economy/Energy/Emissions Model (DIEM). While the modeling includes a broad macroeconomic component, this work is done using solely the detailed electricity dispatch component of DIEM to enhance the level of detail possible in the findings, given that most previous analyses of the IRA have suggested many of the emissions reductions will be realized through changes in electricity generation. This also allows the new EPA GHG proposal to be more effectively added to the modeling. The electricity component of the DIEM 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 (Ewing et al. 2022; Konschnik et al. 2021; Ross 2019, 2018; 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 costs for each model scenario, it is important to view the findings more broadly and evaluate overall

[3] There are some differences in the definitions of these technologies that are accounted for in the modeling.

trends and insights that can be gleaned from the results, rather than focus on specific numbers. Findings are given for a range of sensitivities around the central assumptions in the analysis rather than lumped together so that the relative importance of each variable and forecast can be seen. The next subsection summarizes overall highlights of the analysis, followed by a more comprehensive description of the model and assumptions used, and then details regarding the scenario results for both the IRA and EPA GHG proposals.

Highlights of the Analysis

This section provides a brief overview of the types of findings that hold across a wide range of assumptions about future conditions.

Most Important Factors Influencing the Analysis

A number of factors stand out as having the most influence on analysis results, including:

- How many renewables sites will be available to developers?
- How fast can renewables be built and connected to the grid—and does speed affect the cost?
- What are natural gas prices in the future?
- How much new electricity generation is needed for electric vehicles? [4]
- Which units are affected by a GHG proposal (size and utilization rates)?
- How do delivered hydrogen prices in the future under the GHG proposal compare to those of natural gas? How would potential hydrogen demand affect those prices?
- Is clean hydrogen produced through electrolysis (necessitating more electricity generation) available and at what cost?[5]

Questions to Consider

When examining any modeling results, which reflect the most cost-effective method of planning for the future and may not fully capture site-specific or all potential state-specific difficulties, the following considerations are pertinent for the IRA and EPA GHG proposals:

- How can any potential delays in permitting and siting renewables—and the associated transmission interconnections—be avoided so that utilities and renewable-asset developers can take advantage of IRA tax credits? How can any concerns regarding community impacts caused by renewables and transmission development be allayed?
- How might better regional transmission coordination and expansion enable additional renewable generation under both IRA and any future policies that move the economy toward net zero?

[4] Future analyses will also consider additional sources of increased electricity demand such as data centers, industrial electrification, and other sources.

[5] This analysis includes both scenarios where hydrogen is implicitly supplied from outside the electricity industry and where hydrogen is produced using electrolysis (presumably from renewables). .

- How quickly will fully functioning markets develop for CCS and hydrogen? How might near-term technology build-outs in these areas affect future decisions and costs? (The analysis follows other analyses and assumes that generators can be retrofitted with CCS by early 2030 and have available transport and storage options [EPA 2023A]. Hydrogen markets, to at least some degree, are assumed by 2032.)
- Given anticipated declines in overall coal consumption, utility-specific commitments to eliminate coal, and other factors such as uncertain coal supply chains, will utilities be willing to make significant investments in CCS for coal-fired generation? (Coal shipments as a share of total railroad traffic already declined by 40% in the last decade.)
- How will hydrogen reach electricity generators? If mixed into existing gas pipeline deliveries, what concentrations of hydrogen are feasible? If hydrogen-specific pipelines are required, what are the costs and permitting issues? If hydrogen is produced by utilities on-site, how many locations can accommodate it? What are potential cost savings from colocation of renewable generation and hydrogen electrolysis (not included in the current analysis)? How might hydrogen be stored (e.g., to accommodate seasonal variation in renewable availability and electricity demand)?
- How will hydrogen demands for power generation interact with other potential uses for hydrogen (e.g., industrial processes or transportation) as the economy moves toward net-zero?

Impacts of the IRA on Emissions

- In the absence of the IRA, emissions would trend downwards over time, but at a gradual pace, and improvements would have been quite dependent on fossil fuel prices.
- The IRA substantially accelerates the decline in emissions through 2032, even in the face of recent renewables cost increases. After 2032, future reductions would require additional policies.
- The extent of emissions reductions under IRA remains highly dependent on natural gas prices and the ability to site and permit new renewables generation.
- Electrification of transportation can increase emissions from generation, but total generation emissions would remain at levels well below those today (even before considering emissions savings from the vehicles themselves).
- Extending the IRA credits past 2032 would reduce the immediate pressure to build renewables and would lead to lower emissions in the long term (though slightly higher in the near term). Whether or not an extension applies to nuclear power and CCS will determine the viability of those particular types of units. Expansion in renewable generation would continue beyond the end of the current IRA program, avoiding an emissions increase after the current IRA credits expire (where nuclear retirement after 2032 could potentially lead to construction of new fossil units).

Impacts of Inflation and Increasing Technology Costs

- Recent increases in financing and equipment costs, which have disproportionately large effects on renewables, have dampened the speed of the renewables transition but not altered basic trends.

- Installation of onshore wind represents the largest share of early installations in this decade, with solar accelerating toward the 2030–2032 time frame.
- Cost increases, as reflected in NREL's ATB for 2023, result in estimated IRA emissions that are 13% higher than those based on overnight capital costs from NREL's ATB 2022. (An undramatic but significant increase driven by cost inflation).
- Higher estimates of construction costs shift new capacity installations toward wind and away from solar, and especially away from battery storage.
- Regardless of inflation, retail electricity prices and household electricity bills decrease under the IRA.

Impacts of Site Availability and Permitting for Renewables

- Regardless of higher anticipated renewables costs, the availability of both sites and permitting for renewables can have a major effect on emissions trends. Reductions in the scope of renewables sites can lead to emissions that are 50% higher in 2032 than otherwise expected in under the IRA, and emissions remain around 30% higher through 2050.
- Potential limitations on renewables siting, based on larger setbacks and land exclusions, can leave installations around 100 GW below levels seen in the main IRA modeling.
- If the availability of renewables is limited, emissions can stay well above 500 MMTCO$_2$ per year (130–170 MMTCO$_2$ higher than otherwise forecasted). This is true whether the restrictions are on the availability of sites for development or on the ability of the system to quickly expand the construction of renewables.
- If capital costs escalate from rapid installation of wind and solar, it leads to equivalent levels of future emissions as it is difficult to take full advantage of IRA tax credits while they are available.
- Additional reductions in renewable resources can lead to further emissions increases (cutting sites in half from the limited, or reduced, case leads to another 50–65 MMTCO$_2$ per year).

Impacts of Natural Gas Prices

- If natural gas prices remain low, gas generation will largely displace nuclear[6] once the IRA production credits expire.[7] Cheap gas also displaces many potential new renewables.
- If natural gas were to remain around $2/MMBtu on average in the future, there would be near-term declines in emissions. However, emissions trend upward after 2032, heading back toward levels seen without the IRA. This does not imply that renewables are not being used—albeit at substantially reduced levels—but rather reflects future competition between the low-priced gas, and also nuclear generation (much of which retires after IRA credits expire).

[6] By 2032, new nuclear generation and small modular reactors are not found to be economic in spite of IRA tax credits, based on projected construction costs from EIA (2023b).

[7] Additional scenarios are included in the body of the report that examine implications of extending IRA credits beyond 2032, both with and without the credits for nuclear generation.

- This "cheap gas" future (based on delivered gas prices from EPA 2023c) lowers potential emissions reductions from more than 40% cumulatively, based on the standard assumptions in the IRA modeling, to around a 15% reduction through 2050 with the low-priced gas.

Impacts on Regional Capacity Investments

- The IRA can dramatically change the desired investments in renewables in some regions of the country, while other regions might adopt similar strategies irrespective of the IRA.
- Variations in gas prices have large effects in some regions, but limited impacts in other areas.
- Demand for renewable generation increases under the IRA, regardless of any limits on the number of sites available. Regional differences associated with potential restrictions on renewable resources can, however, be significant.
- Limited quantities of existing coal plants are inclined to retrofit with CCS (around 6 GW) under the IRA. Most of the units are built in regions where the captured CO_2 can be used for enhanced oil recovery (even though IRA credits are lower for this type of eventual storage).
- In some regions, a significant number of miles of new spur transmission lines will be needed to connect new renewables to the grid. However, interregional expansion of long-distance transmission may be limited, based on current costs.
- In most policy modeling (including this analysis), nongenerating fossil units tends to remain available in the future to help provide reliability when there are high levels of renewables in the system. On average under the IRA in 2032, more than 70% of the capacity used to meet reserve margins is from fossil units (not including nuclear).

Impacts of the EPA GHG Proposal

- The EPA GHG proposal can potentially cut in half the emissions remaining after the conclusion of the IRA. However, the proposal does not reach net-zero emissions from generation by 2050.
- Changes in US average retail electricity prices average less than 2% in most scenarios.
- Emissions under the EPA GHG proposal still depend on natural gas prices and renewables availability, along with sources of clean hydrogen.
- Coal plants retrofitting with CCS increase to around 30 GW by 2030, compared with 6 GW for the IRA over the same time period (for most cases, no gas with CCS is forecasted).
- Based on the standard assumptions in the DIEM model, the majority of emissions reductions come from coal CCS prior to 2038. After 2038, hydrogen markets contribute most of the additional reductions, but renewable generation does increase in response to the proposal.
- Annual storage needs expand from around 25 $MMTCO_2$ under the IRA to more than 200 $MMTCO_2$ under the EPA GHG proposal (most of which is still used for enhanced oil recovery).

- Overall renewable installations are higher by 2030 as the result of the GHG proposal. Onshore wind installations, in particular, are up to 30 GW higher than with the IRA alone.
- The costs per ton of CO_2 reduced for the proposal range from $7 to $12 based on the standard assumptions in the modeling, where the carbon price within that range depends on the size and utilization rate criteria applied to gas combined-cycle units.
- The availability and cost of renewable generation have larger impacts on emissions and the costs per ton reduced than do the modeled range of criteria for gas turbines.

Impacts of Hydrogen Costs

- The relative prices of natural gas and hydrogen, or any costs associated with retrofitting gas units to cofire with hydrogen, have large effects on both emissions and costs.
- If capital expenditures (equivalent to 20% of the cost of a new gas combined-cycle unit [NREL 2020]) are needed to either build a new gas unit capable of burning hydrogen or retrofit existing combined-cycle units for hydrogen cofiring, very few units are willing to accommodate these expenses in order to burn hydrogen. Most existing gas units instead choose to avoid the hydrogen criteria by remaining below a 50% utilization rate.
- Similarly, if delivered hydrogen costs $1/kg instead of the $0.5/kg assumed in other scenarios (EPA 2023a), units will find it uneconomic to use hydrogen and will meet GHG proposal requirements in other ways that either avoid gas generation from larger units or reduce their utilization rates. All demand for hydrogen can be eliminated in this case.
- If low-priced gas is available (around $2/MMBtu), there is also a significant drop in demand for hydrogen at $0.5/kg ($3.7/MMBtu).
- If the clean hydrogen needed under the EPA GHG proposal is provided by electrolysis, significant amounts of new generation may be required. If the availability of renewables is limited in this scenario, even more gas generation will be required in the system. Solar PVs also expand to meet any electrolysis needs.

[8] The standard assumptions in the DIEM model regarding natural gas prices are based on the Annual Energy Outlook's (EIA 2023a) Henry Hub wholesale gas price, combined with regional transport costs and seasonal price effects. For the main IRA scenarios, this gives an average delivered price of $3-$3.5/MMBtu in most years. The Cheap Gas scenarios instead rely on the EPA IPM (EPA 2023c) delivered retail gas prices, which are closer to $2/MMBtu in the IRA scenarios.

[9] Setting aside minor changes in technologies (which are incorporated in the modeling), solar and battery storage costs in the Standard Assumptions are roughly 30% higher in NREL's ATB 2023, compared with the previous ATB 2022. Onshore wind costs are 14% higher; offshore wind costs are largely unchanged, which may overstate their contributions.

CORE FINDINGS

Summary of IRA Findings on Emissions Trends

Emissions from electricity generation were trending downwards prior to passage of the IRA and were expected to continue along these trends (see the No IRA Baseline forecast in Figure 1), but at a modest rate that depended to a large extent on the price of natural gas (see, for example, the No IRA [Cheap Gas] scenario).[8] With the passage of the IRA, its tax credits accelerate the transition to renewable generation significantly, leading to a sharp decline in emissions through 2032, shown by the IRA (Standard Assumptions) case. Recent increases in financing and equipment costs, which have a disproportionately large effect on renewable installations compared to fossil fuels, have dampened the speed of this transition, but not altered its basic trends—IRA Standard Assumptions (based on NREL's ATB 2023) versus IRA w/ATB 2022 Costs.[9] Although cost increases have had some impact on the economic advantages provided to renewables by the IRA tax credits, emissions based on the current costs are only 13% higher than previously anticipated under the lower ATB 2022 costs, and emissions remain well below the case without the IRA.

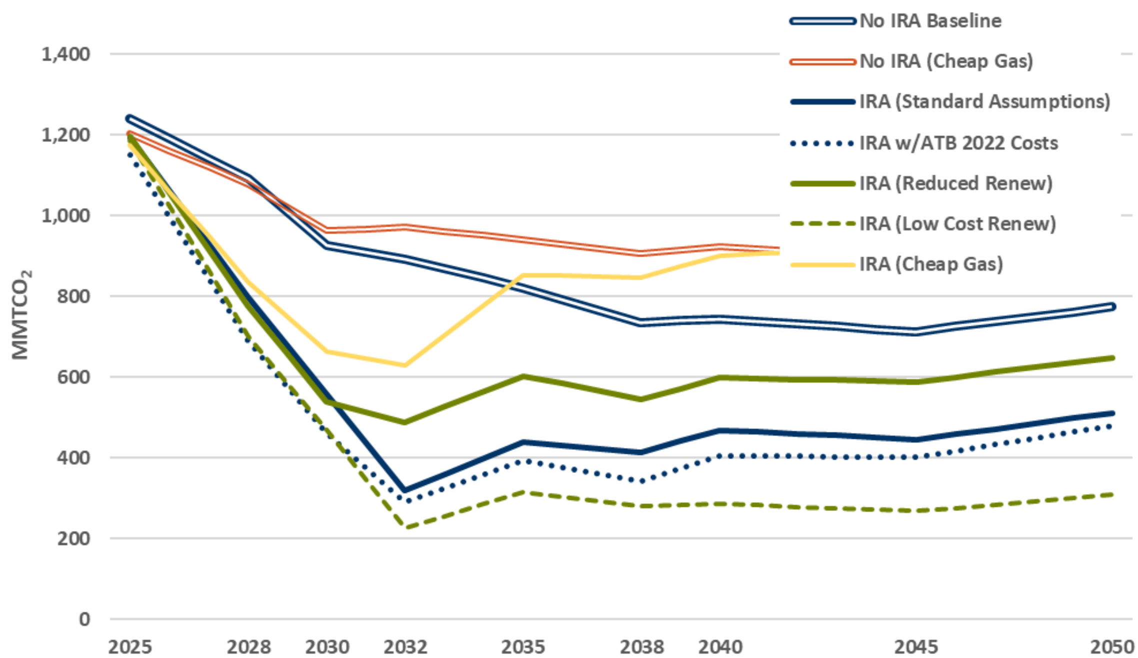
Even with higher anticipated renewables costs, the availability of both sites and permitting for renewables can have a major effect on emissions trends. Reductions in the scope of renewables sites (Reduced Renew) can lead to emissions that are 50% higher in 2032 than expected in the standard IRA scenario, and emissions remain around 30% higher through 2050.[10] Conversely, if renewable technologies advance more rapidly (Low-Cost Renew) and fewer restrictions are in place regarding siting, emissions decline more quickly in the near term and remain at lower levels throughout.[11]

The influence of natural gas prices on emissions and on the ability of renewables to compete on a cost basis has waned somewhat over recent years as equipment costs for renewables have declined significantly. However, competition between gas and renewables can still be seen, particularly on a regional basis, depending on seasonal gas prices and the availability of renewables (and the ability of the transmission system to redistribute renewable generation). If natural gas were to remain around $2/MMBtu on average in the future, there are near-term declines in emissions as shown in the IRA (Cheap Gas) scenario. However, after 2032 (with the expiration of new IRA tax credits) emissions trend upward, heading back toward the No IRA levels. This does not imply that renewables are not being used—albeit at substantially reduced levels—but is more a reflection of future competition between the low-price gas and existing nuclear generation, much of which retires after IRA credits expire, as will be seen in the capacity and generation results in the main body of the report.

[10] The Reduced Renewables case is based on NREL's Reduced case in their Standard Scenarios (2022b) and include additional restrictions on renewables setbacks and land exclusions.

[11] The Low-Cost Renewables case is based on NREL's Advanced scenario, rather than the NREL Moderate assumptions used in all other model runs (NREL 2022b).

Figure 1. Emissions trends: No IRA versus With IRA



Source: DIEM model

Summary of IRA Findings on Renewables Investments

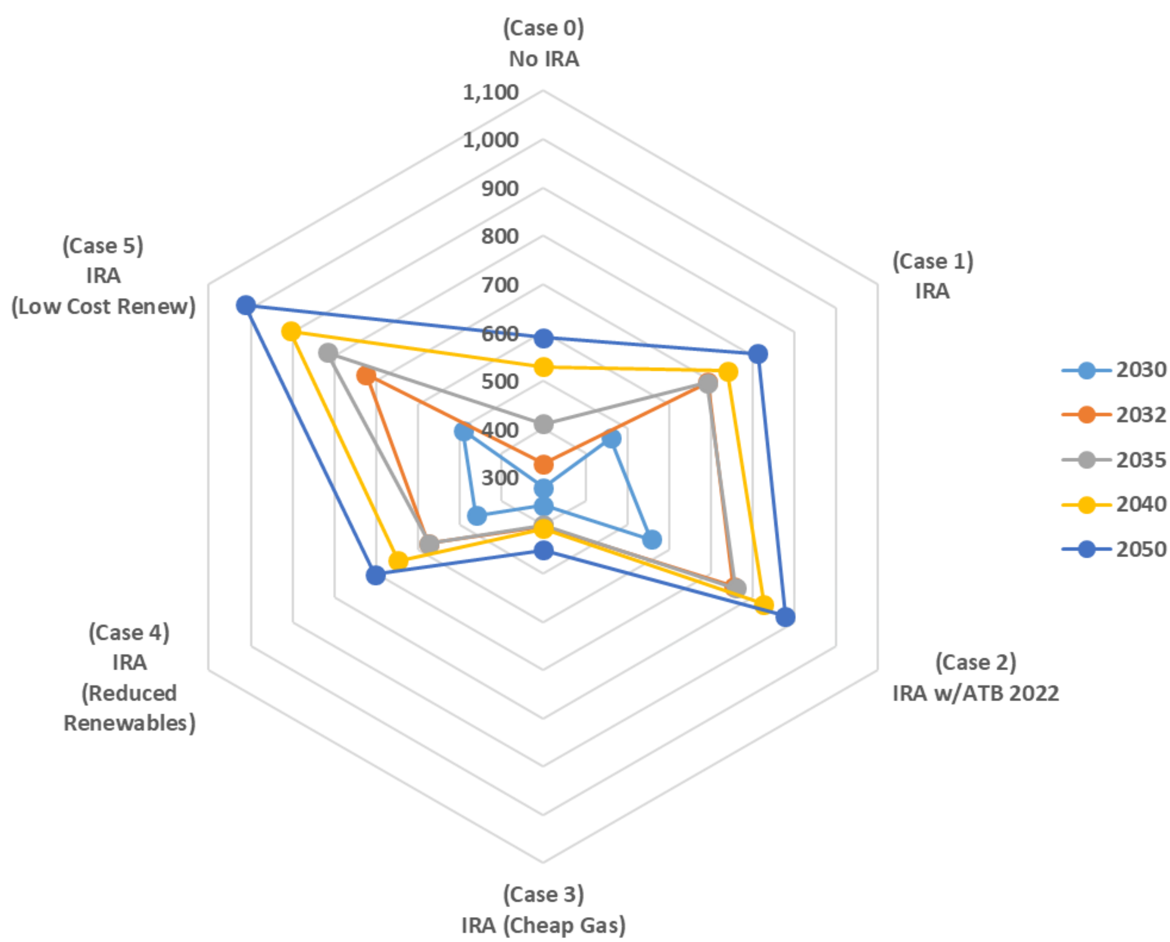
Turning to the renewable capacity additions that underpin these emissions trends, Figure 2 shows cumulative solar plus wind capacity investments between 2020 and the year shown by each line in the graph. Reading out from the center of the graph (scaled to start at 300 GW to highlight the different impacts) shows expansions in cumulative renewable capacity by the different years. This is illustrated for the standard No IRA scenario and compared to the range of IRA scenarios from Figure 1. Moving in a clockwise fashion from the No IRA results at the top of the graph, these sensitivities include: (1) the main IRA scenario that uses the standard assumptions from this analysis, (2) an IRA scenario that uses the lower-cost renewables assumptions from the NREL ATB 2022, (3) a scenario that uses the low-price natural gas discussed previously, (4) a scenario that uses data from the NREL reV (NREL 2023b) and Regional Energy Deployment System (ReEDS) (NREL 2022b) models with more limited access to renewables sites, and (5) a scenario that uses forecasts of lower-cost renewables from NREL's Advanced Technology case instead of NREL's Moderate Technology case (NREL 2023a).

Between 2020 and 2035, for example, around 400 GW of solar plus wind capacity is installed without the IRA. This increases substantially to around 700 GW with implementation of the IRA, even factoring in the recent higher renewables costs. Total new installations would be closer to 800 GW, if costs were to land at the levels anticipated in the ATB 2022 forecast. The combination of low-price gas and current revised higher renewable costs leave cumulative installations by 2035 at around 400 GW under the IRA (Cheap Gas) case. Limitations on renewables siting (Reduced Renewables) leave installations around

100 GW below those seen in the main IRA runs. Conversely, the more rapid improvements in renewable technology reflected in NREL's Advanced Technology Scenario (Low-Cost Renew) leads to an additional 125 GW of solar plus wind by 2035 compared to the main IRA assumptions, rising to around an additional 200 GW by 2050. Additional details on the timing and regional distribution of capacity installations and retirements are presented in the Model Results section of the report.

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. IRA tax credits can potentially accentuate these regional differences. Figure 3 looks at cumulative investments and retirements between 2020 and 2032 and compares No IRA and With IRA forecasts across 15 regions of the country (see Figure 14 for regional definitions). Note that these results for the No IRA and With IRA scenarios use the standard DIEM assumptions

Figure 2. Solar + wind capacity investments – cumulative additions from 2020 (in GW)



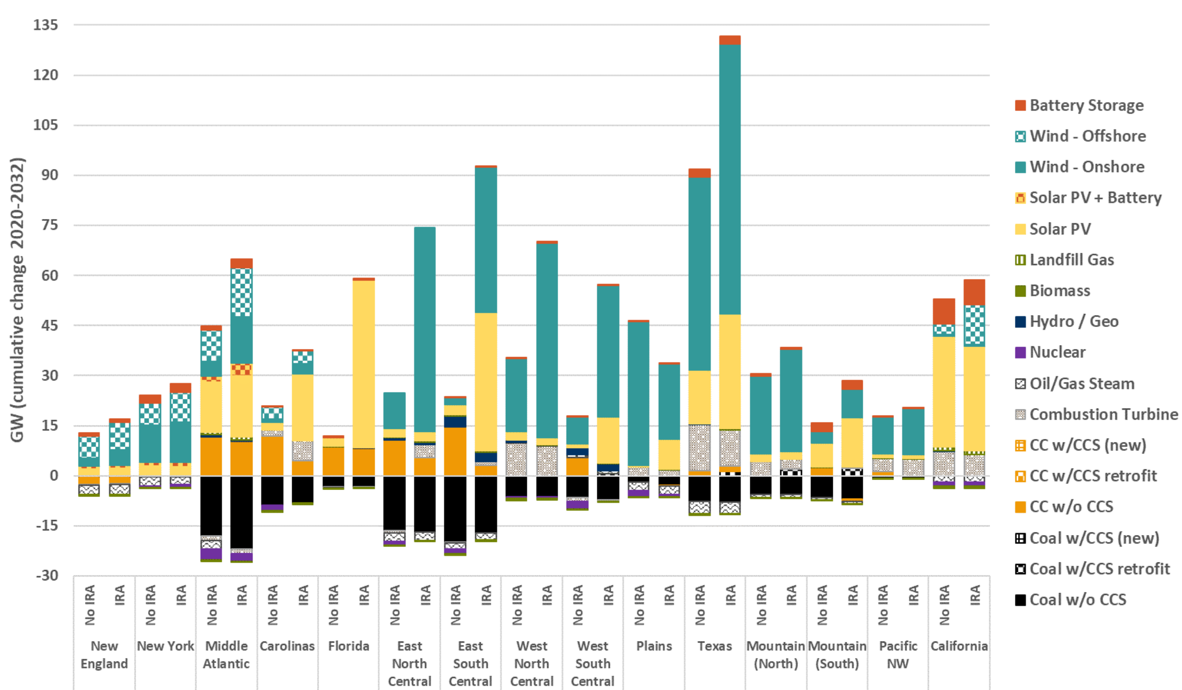
Source: DIEM model

that gave the IRA (Standard Assumptions) emissions trends in Figure 1 (including the higher renewables costs in the ATB 2023). Note also that these regional findings already include preexisting state policies, based on EPA documents (2023c).

As Figure 3 shows, the economics of renewables, and other generation, can change dramatically in some regions as the result of the IRA, while other regions might adopt similar strategies regardless of the IRA. Policy implications on the coasts—New England, Florida and California, and to a lesser extent, New York and the Pacific Northwest—are fairly comparable with and without the IRA. Other regions see a wider range of impacts. States in the Middle Atlantic region add more solar and onshore wind under IRA and fewer combined-cycle units, while the Carolinas shift the forecasted mix somewhat under IRA and also expand their turbine fleet more quickly to enhance future reliability in the system. The four Central regions see some of the largest increases in renewables, especially for wind resources. Texas also expands wind generation, but was already on a path toward increased wind prior to IRA. Texas also sees a larger relative increase in solar. Many of the CCS retrofits on coal plants occur in Texas and some mountain states, along with a few in Louisiana (in the West South Central region), to take advantage of negative cost opportunities for CO_2 storage in enhanced oil recovery (EOR). The Mountain regions see significant changes in investments in relative terms, but smaller absolute changes than other regions.

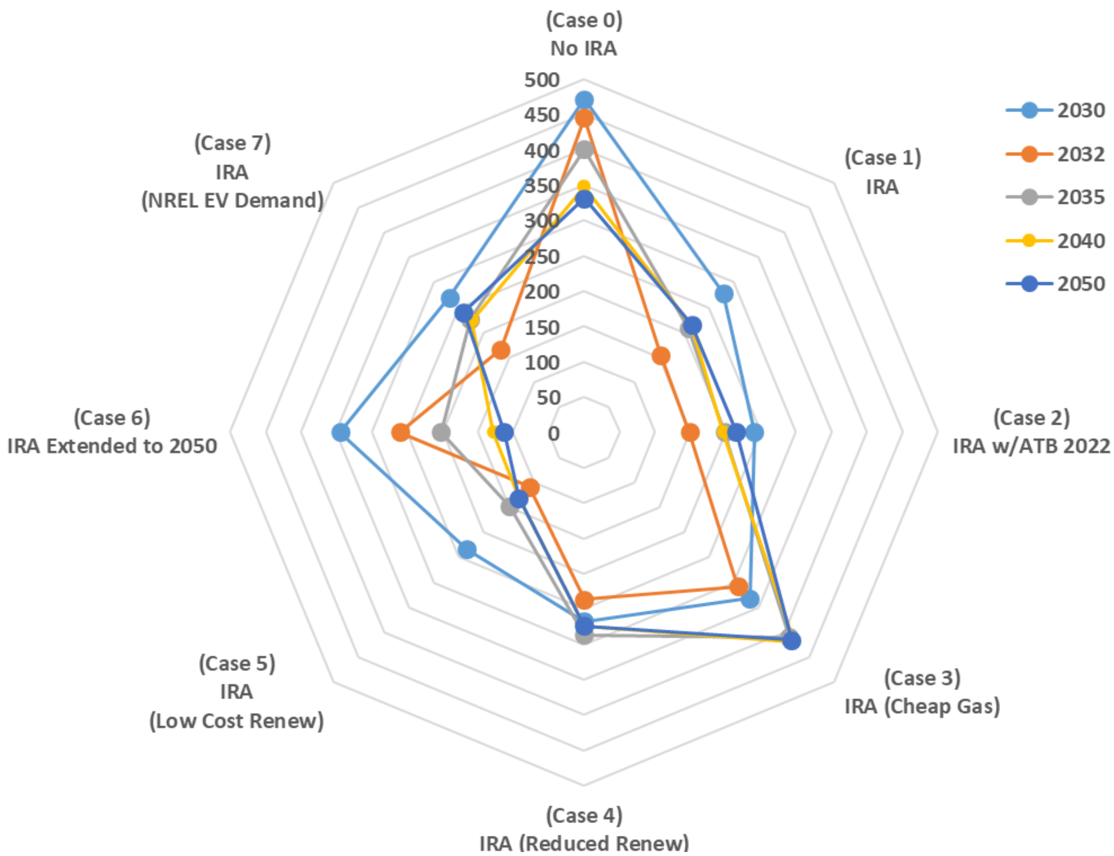
Figure 4 examines the average CO_2 emissions intensity of generation across the years for a variety of scenarios, measured in pounds of emissions per megawatt hour (MWh). This metric provides a convenient summary measure of how the electricity system as a whole is

Figure 3. Cumulative regional capacity changes through 2032: No IRA versus With IRA



Source: DIEM model

Figure 4. Average CO_2 emissions intensity of generation (lb/MWh)



Source: DIEM model

responding to policies and scenario assumptions since it combines the effects of renewable installations with the operation and/or retirement of fossil and nuclear generation. In addition to the sensitivity cases from Figure 2, the graph also includes data for a couple of policy alternatives that are explored in the Model Results section of this report; one case in which the IRA tax credits are extended through 2050 and another in which higher electricity demand from electric vehicles is considered (NREL 2018).[12]

Compared with a nationwide emission intensity of around 800 lb per MWh in 2022 (EIA 2023a), the No IRA scenario shows a continuing improvement without the IRA incentives (approximately 475 lb/MWh in 2030 and 450 lb/MWh by 2032). The IRA provides large improvements in emissions intensity over its horizon. In 2030, rates are around 275 lb/MWh in 2030 and decrease even more to 155 lb/MWh by 2032, before beginning to rise after the end of the IRA incentives. The higher renewables costs in the main IRA scenario lead to larger intensities than would have been seen previously using the ATB 2022 forecasts of costs, but by 2032 the intensities are fairly comparable. The IRA combined with lower-price natural gas shows initial improvements in emissions intensities, but to a lesser extent than

[12] The figure only considers emission from generation and does not factor in reductions achieved by removing fossil-powered vehicles from the roads.

if gas prices are higher, and by 2040 the cheaper gas leads to intensities that have expanded by one-third as renewables growth is constrained and nuclear plants retire. Alterations in the availability or cost of renewables shown in the next two data points around the diagram move in the expected directions, respectively.

The IRA Extended to 2050 scenario (Case 6) looks at how extending the IRA tax credits through 2050 might help alleviate any near-term haste to install renewables before the program expires, perhaps comparable to how renewables incentives have been extended in the past as they approach expiration.[13] The slower pace of renewable construction under the extended policy results in higher emissions intensities through 2032, but eventually leaves emissions lower than the other scenarios (but not at net-zero emissions from generation by 2050). This reflects that there is more of a rush to renewables when the credits are expected to expire sooner and installations that are more spread out over time when there is no pending expiration to consider.

The NREL EV Demand scenario (NREL 2018) incorporates additional potential demand from personal electric vehicles (Case 7), which in this case led to around an additional 10% in electricity demand by 2032 and more than 20% additional demand by 2050. Through the horizon of IRA to 2032, the extra demand has little impact on emissions intensity, although total generation and emissions have increased. This also largely holds true through 2050 in intensity terms, but higher total demand by 2050 leads to additional absolute emissions from generation (before accounting for the declines in emissions from removing gas-powered internal combustion engines from the roadways).

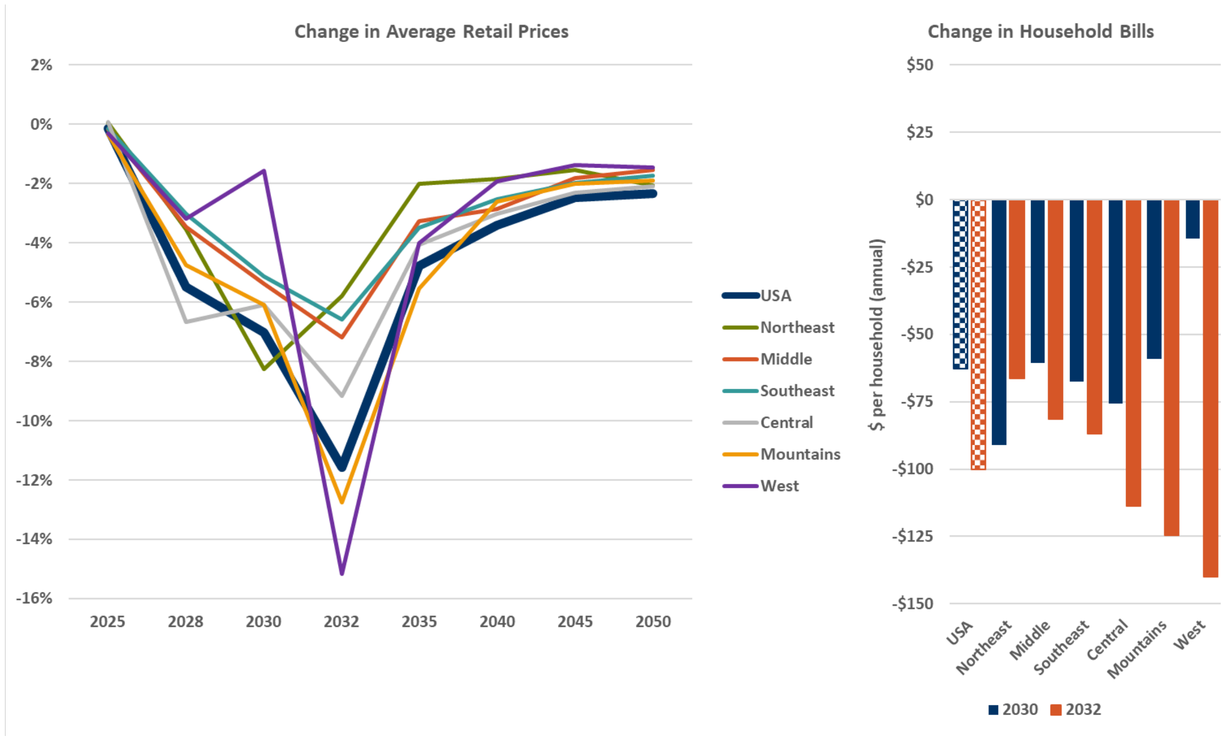
Summary of IRA Findings on Costs

Costs and benefits of the IRA can be more difficult to evaluate than is typical in policy analyses for two reasons: (1) costs of the tax credits are borne outside of the electricity system, and (2) the price of natural gas is significantly lower in the IRA scenarios than in the No IRA scenarios. Thus, any cost results for IRA should be interpreted with caution. With that caveat, Figure 5 shows relative changes in retail electricity prices between the IRA and No IRA cases in DIEM for a five-region aggregation of the state-level results, along with US-average impacts. These changes are also expressed as the corresponding dollar change in average annual residential household electricity bills (all dollar values in this paper are expressed as 2020$). As seen in other analyses, subsidizing specific types of generation such as renewables can lower the marginal costs of generation, to the extent that electricity from new renewables is the price-setter in the markets during at least some seasons of the year and times of day. Lower gas prices in the IRA scenarios also reduce operating costs for the types of gas units that can be market price-setters on the margins.

The declines in estimated prices tend to peak during final year of the IRA implementation as it represents the point with the most new capacity and generation receiving tax-credit subsidies. Impacts can vary by region and year depending on the timing of the new

[13] This version of the IRA extension includes both the production tax credits for nuclear generation and those for CCS; however, an alternative approach in the body of the report drops these credits and focuses on extending the renewables credits. The emissions implications of either extension are similar.

Figure 5. Changes in electricity prices and household bills under the IRA (versus No IRA)



Source: DIEM model

renewables generation, but most follow a similar pattern, with declines in prices ranging from 6% to more than 12% in 2032 (averaging around 11%). Converting these price declines into a measure of household spending gives an average decline of up to $100 per household per year by 2032, the highest-impact year. At a regional level, these declines range from $66 per household in the Northeast to $140 in the West in 2032. However, there is more variation in 2030 prior to the final year of the IRA.

Summary of EPA GHG Proposal Findings on Emissions Trends

The EPA GHG proposal targets emissions from baseload and intermediate-load fossil fuel-fired units that continue operation once the renewables subsidies of the IRA are taken into account (note that all EPA GHG scenarios to be presented will already include the effects of the IRA legislation). The full list of CCS and hydrogen cofiring requirements included in the analysis are illustrated in Figure 14. The EPA Regulatory Impact Analysis (RIA) of the proposed rule (EPA 2023a) plans—among other things—to define the size of affected existing combined-cycle turbines as greater than 300 MW at utilization rate of 50% or higher. Table 1 provides an initial ranking of how variations in these criteria compare with other potential market conditions that may impact how the GHG proposal would affect the industry. While nontrivial, potential variations in the size and utilization rate criteria (e.g., affected gas units greater than 100 MW instead of 300 MW, or running at a 40% utilization rate rather than 50%) have less impact on emissions and policy costs than other considerations such as the availability and cost of renewables.

Table 1. Relative impacts of variables in the EPA GHG proposal

Variable	Relative Influence on Emissions: Minimal	Moderate	Significant
Size of combined cycle unit (300 MW or 100 MW)	•	—	—
Utilization rate of combined cycle (50% or 40%)	•	—	—
Costs of renewables	—	•	—
Availability of renewables	—	•	—
Relative price of natural gas versus hydrogen	—	—	•
Potential costs of retrofitting combined cycle for hydrogen cofiring	—	—	•
Clean hydrogen produced through electrolysis	—	—	•

Among the most important assumptions are those regarding hydrogen markets, including: (1) how does the cost of hydrogen compare to natural gas; which will control how much gas units may lean into or attempt to avoid hydrogen cofiring requirements, (2) do existing or new gas units face additional costs associated with being equipped to burn hydrogen (DIEM modeling would normally assume that these additional costs are equivalent to 20% of the cost of a new combined-cycle unit, based on NREL ReEDS model data [NREL 2020]), and (3) how is the hydrogen produced for cofiring in gas units (i.e., through electrolysis that requires additional generation or outside of the electricity system, such as steam reforming of natural gas with CCS)?

Figure 6 contrasts the main IRA emissions trends (based on the standard DIEM modeling assumptions) to a range of possibilities for the EPA GHG proposal.[14] In contrast to what was seen in the EPA modeling for the Regulatory Impact Analysis (RIA) of the GHG proposal (EPA 2023a), there appears to be the potential for significant additional emissions reductions from layering the EPA GHG proposal on top of the IRA trends. When examining the results, note that only the emissions trends for the main EPA GHG case and the case labeled EPA GHG (H_2 Fuel Cost = $1/kg) are directly comparable to the IRA trend shown in Figure 6; the other EPA GHG proposal trend lines would need to be contrasted to the appropriate corresponding emissions trajectories in Figure 1.

Part of the larger emissions impact from the EPA GHG proposal than seen in the EPA modeling (EPA 2023a) may be the result of directly incorporating proposal criteria for actions by existing gas units into the DIEM modeling. Other parts of the differences are related to assumptions—among other factors—about the relative differences between natural-gas and hydrogen prices, as is discussed in more detail in the Model Results section of this report.

In the DIEM model results in Figure 6, there is little variation in emissions across a range of potential size and utilization rate criteria for gas turbine units. These criteria are omitted from the figure as they would not be observably different from the main EPA GHG emissions trend illustrated in Figure 6 (all results in this figure are based on the assumption that impacted existing combined-cycle units are those greater than 300 MW that operate more than 50% of the year).

The emissions reductions seen in the DIEM modeling of the EPA GHG proposal rely on development of both CCS and hydrogen options. Markets and transport systems have to be ready to capture CO_2 at generators, move the CO_2 through pipelines or other means, and then inject it into storage facilities. Unlike findings for the IRA policy that resulted in 6 GW of existing coal plants retrofitting with CCS, modeling for the EPA GHG proposal implies retrofitting of 30–35 GW by 2030. Annual storage needs expand from around 25 $MMTCO_2$ under the IRA to more than 200 $MMTCO_2$ under the GHG proposal (most of which is still used for enhanced oil recovery, which remains the most cost-effective option in spite of its lower IRA tax credits). For the period 2030–2037, expanded CCS contributes the majority of the additional emissions reductions compared to the IRA trends. After 2038, hydrogen markets contribute most of the additional reductions, given that retrofitted CCS units are liable to retire by the time IRA credits for CO2 capture expire, potentially calling into question the practicality of some of these CCS investments.

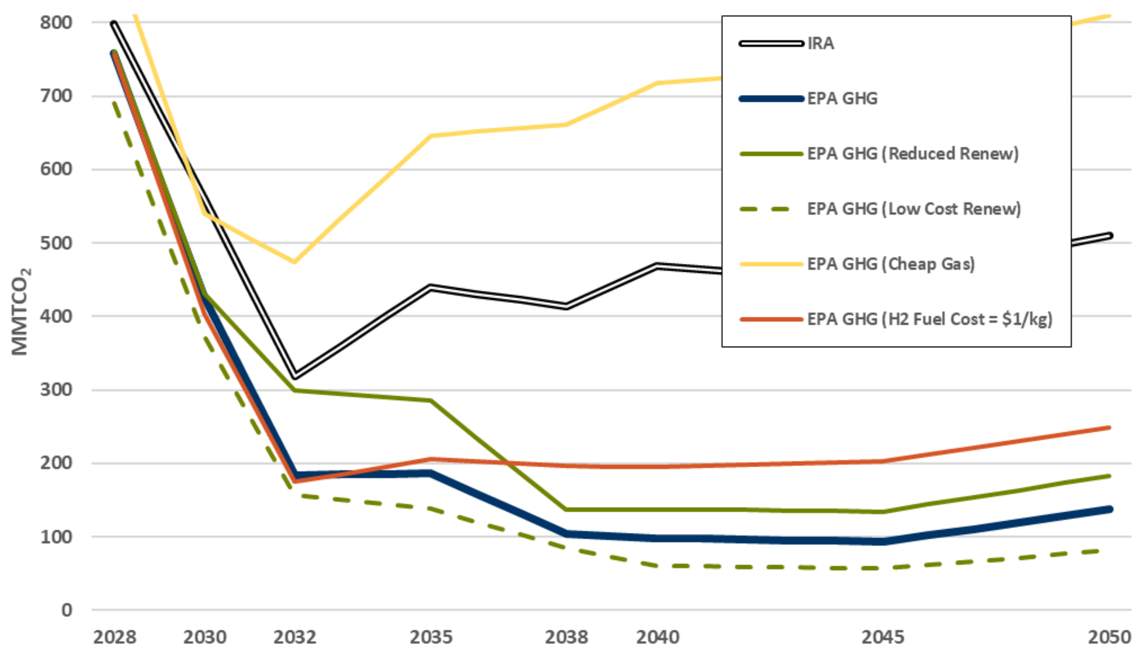
Although the DIEM modeling in this analysis includes relatively detailed estimates from the EPA Integrated Planning Model (IPM) (EPA 2023c) regarding the potential costs of CCS retrofits on coal plants and the costs of transporting and storing the resulting CO_2,[15] future hydrogen markets and the associated costs remain more speculative. The main EPA GHG proposal runs in DIEM adopt EPA's (2023a) assumption that delivered hydrogen prices are $1 per kg ($7.4/MMBtu) until 2032, when they drop to $0.5 per kg ($3.7/MMBtu).[16]

Even before examining the specific fuel choices made by gas-fired units—mainly combined cycle—the importance of the relationship between gas prices and hydrogen prices can be seen by contrasting emissions trends for the main EPA GHG scenario with those from the EPA GHG (Cheap Gas) and EPA GHG (H_2 Fuel Cost = $1/kg) cases in Figure 6, both of which

[14] The main scenarios in DIEM, unless otherwise specified, rely on the assumption in the EPA Regulatory Impact Analysis (EPA 2023a) that delivered hydrogen prices—including transport and storage—are $0.5/kg (equivalent to $3.7/MMBtu) after 2032 (the prices is equal to $1/kg prior to 2032).

[15] DIEM also includes the ability to retrofit gas plants with CCS, or build new coal or gas plants with CCS, but these options are generally not found to be cost-effective.

Figure 6. Emissions trends: Factors influencing EPA GHG proposal results



Source: DIEM model

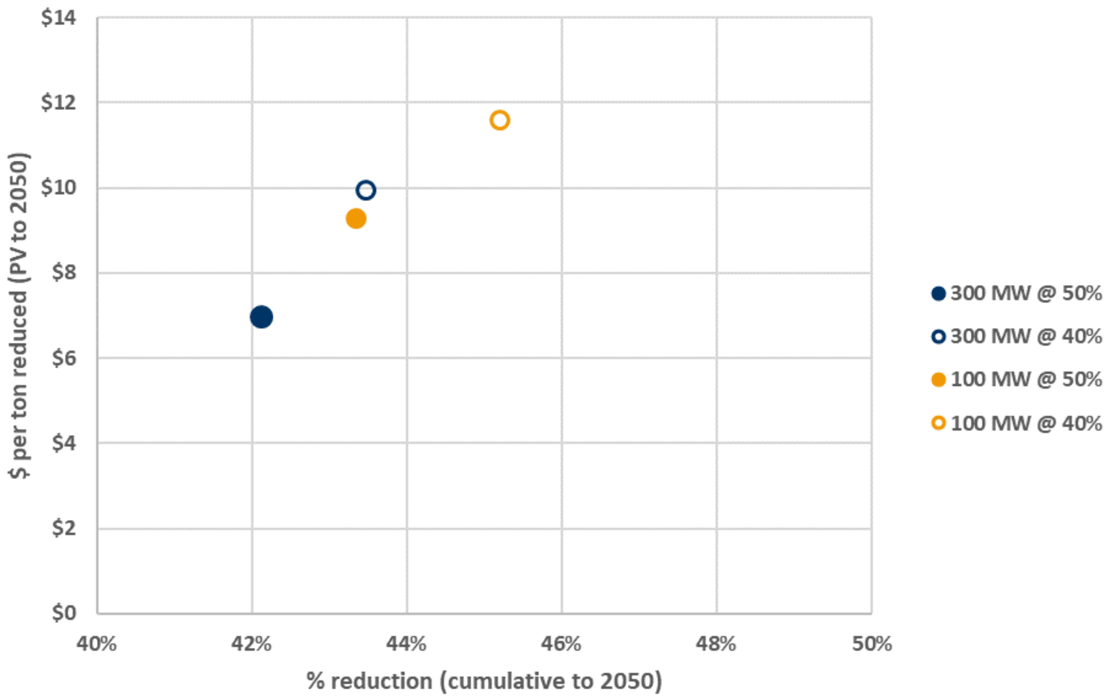
involve natural gas prices below those of the assumed hydrogen price. As was seen in the IRA runs, the Cheap Gas assumption has by far the highest emissions. In contrast, holding the hydrogen price at $1/kg effectively removes most of the motivation to burn hydrogen and instead leads to shifting among the different sizes of combined cycle units in order to avoid the hydrogen requirements (i.e., gas units greater than 300 MW tend to stay below the 50% rate threshold, while smaller units contribute a larger share of overall gas generation). The result of these adjustments is emissions holding steady at the levels achieved in 2032 when the hydrogen criteria begin. However, emissions do not further decrease in response to the higher hydrogen-concentration requirements beginning in 2038. Alternative assumptions for renewables shift emissions in similar ways to those seen in the IRA scenarios.

Summary of EPA GHG Proposal Findings on Costs

Figure 7 summarizes costs and cumulative emissions reductions for several potential variations of the EPA GHG proposal's criteria. The present value of costs per ton of CO_2 reduced are contrasted to the cumulative percentage reduction in emissions from

[16] More typically, the DIEM model would use estimates from NREL's ReEDS model regarding the costs of, and inputs to, hydrogen production technologies. However, as these markets are not currently well-developed at scale, and transport and storage costs and options remain open questions, this analysis used EPA's standardized delivered hydrogen prices for comparison. In DIEM scenarios where the potential amount of electricity needed to produce the hydrogen through electrolysis, rather than other means such as steam methane reforming with CCS, DIEM used NREL ReEDS estimates of electrolysis efficiency.

Figure 7. EPA GHG: Cost of CO_2 reduction ($2020/ton) versus % reduction in CO_2



Source: DIEM model

electricity generation (compared to an IRA scenario with similar assumptions about market conditions)—both variables calculated through 2050 to get a sense of the overall cost effectiveness of each option (and to ensure capturing most of the capital costs associated with each alternative). The main set of assumptions for existing gas combined-cycle units (used in all GHG proposal results in the paper unless otherwise specified) is that affected units include those greater than 300 MW and running more than 50% of the time, and that affected new combined cycle units—assumed to be larger than 300 MW—that are running at more than 50% face additional hydrogen cofiring requirements starting in 2038 (see Figure 14 for a diagram of details about the GHG proposal criteria for all units). The other options shown in Figure 7 look at either reducing the utilization rate requirement to 40% for both existing and new units and/or reducing the size of affected existing units to 100 MW.[17]

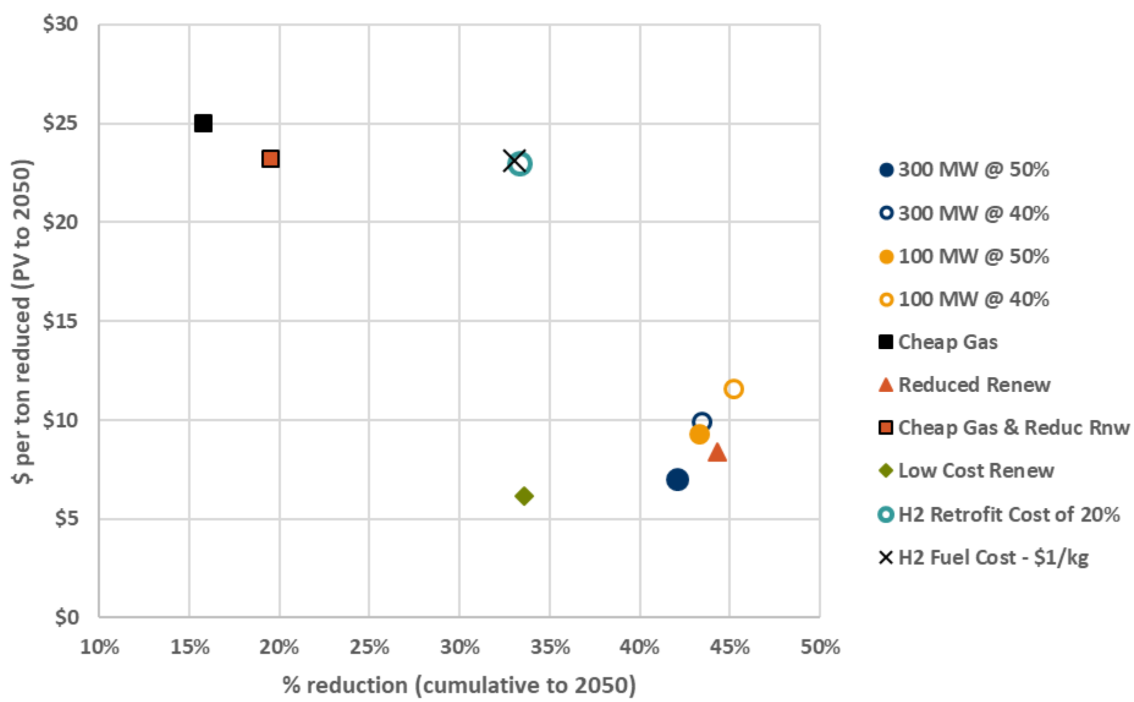
Overall, costs per ton range between $7 and $12 across these options, significantly less than estimates of the social cost of carbon (SCC) that measures potential damages associated with emissions even before any accounting for the other benefits associated with reductions in fossil fuel pollution (the current Biden administration SCC estimate is $51 per ton).[18]

[17] The DIEM modeling suggests that simple-cycle combustion turbines are unlikely to run at more than the 20% utilization rate specified in the EPA RIA (EPA 2023a)—and in fact run very little in their role as peaking units—so variations in criteria for simple-cycle turbines are not considered.

In absolute terms, there is not too much variation across either the costs per ton or the cumulative emissions reductions (which vary between 42% and 45%) but, in relative terms, more restrictive criteria regarding the existing combined-cycle units (meaning lower capacity and utilization rate thresholds) can increase costs per ton by 33% to 66% without much impact on overall emissions. Though, as noted, any of these cost estimates are significantly lower than the SCC.

Although changes in these GHG proposal criteria have comparatively limited effects on emissions reductions (and costs in absolute dollars-per-ton terms), other potential sets of market conditions can alter the results much more dramatically. Figure 8 contrasts the main GHG proposal assumptions (based on affected existing gas units including those larger than 300 MW and running more than 50%) with alternate sets of assumptions about the future (while holding constant the assumptions regarding affected gas units). A Cheap Gas future based on delivered gas prices from EPA (2023c) lowers potential emissions reductions from

Figure 8. EPA GHG sensitivities: Cost of CO_2 reduction vs % reduction in CO_2 emissions



Source: DIEM model

[18] Comparable costs per ton in EPA's RIA (EPA 2023a) appear to be around $27/ton. However, direct comparisons may be inaccurate because existing gas units were handled in the analysis through calculations outside of the electricity modeling.

more than 40% cumulatively to around 15% through 2050. The cost per ton also rises to around $25/ton—roughly equivalent to that implied by the EPA RIA (EPA 2023a).

A future in which renewables are available in more limited quantities has less of an impact in relative terms, with emissions reductions and costs per ton similar to the main GHG scenario, but in absolute terms annual emissions are significantly higher than if more renewables sites are developed (see Figure 6). The availability of lower-cost and more-efficient renewable technologies (the Low Cost Renew based on NREL's Advanced scenario) provides fewer additional emissions reductions from the GHG proposal, but only in relative terms compared to an IRA scenario where the same renewables technologies are available—in absolute terms, the combination of advanced renewables and the GHG proposal has the lowest total emissions across the scenarios illustrated in Figure 6.

Finally, along with natural gas prices, the price and/or cost of using hydrogen can have potentially significant—and roughly comparable—impacts on the costs per ton of CO_2 reduced. If capital expenditures equivalent to 20% of the cost of a new gas combined-cycle unit are needed to either build a new gas unit capable of burning hydrogen or retrofit existing combined-cycle units for hydrogen cofiring (NREL 2020), the costs per ton of the main GHG proposal case rise from around $10/ton to $23/ton—and very few units aside from limited amounts of new construction are willing to accommodate these expenses to burn hydrogen. Most existing gas units instead choose to avoid the hydrogen criteria by remaining below a 50% utilization rate (see Figure 43). Similarly, if delivered hydrogen costs $1/kg instead of $0.5/kg, units will find it uneconomic to use hydrogen and will meet the GHG proposal requirements in other ways that either avoid gas generation from larger units or by reducing utilization rates.[19]

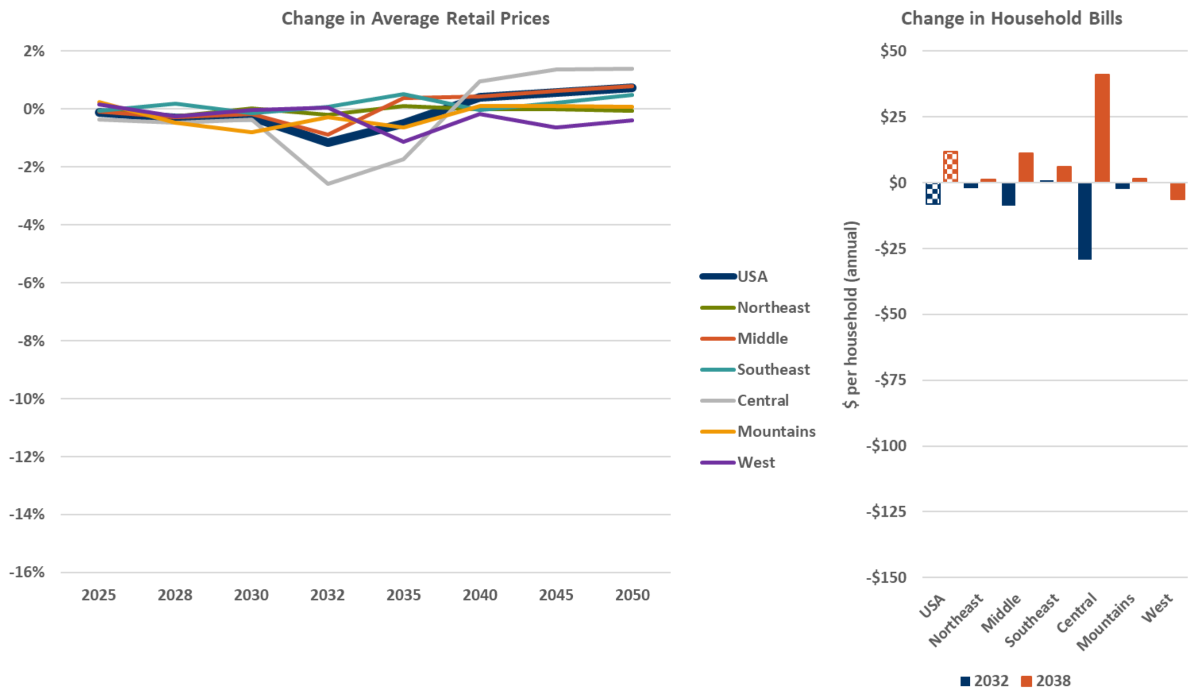
Figure 9 looks at retail electricity price changes (compared to those from the IRA) and changes in the total cost of electricity for households using the same scale as in Figure 5, but focusing on the main years of the EPA GHG proposal, 2032 and 2038. Compared to the larger impacts associated with the IRA tax credits, retail electricity prices are relatively unaffected by the EPA GHG proposal but have a slight upward trend after 2038 when the proposal is in full effect. As with IRA, within these relatively low national impacts, there can be more variation at a regional level. The coasts see little effect, while the central states can potentially experience larger impacts toward 2038.

Summary of EPA GHG Proposal Findings on Hydrogen Demand and Supply

Unlike what was seen in the EPA RIA for the GHG proposal, which had hydrogen consumption of 0.06–0.35 quadrillion Btu (equivalent to 1% to 4% of its natural gas consumption),[20] several of the DIEM scenarios suggest the possibility of using comparatively large quantities of hydrogen in gas units.[21] In the main EPA GHG scenario, which has gas prices in at least some regions and times of the year that are higher than a hydrogen price of $0.5/kg (see Figure 12), modeling in the DIEM scenarios show hydrogen consumption can reach 2.5 quadrillion Btu when the final hydrogen requirements take effect in 2038.

[19] The addition of CCS to gas combined-cycle units also remains an uneconomic alternative.

Figure 9. Changes in electricity prices and household bills from the EPA GHG proposal



Source: DIEM model

Lowering the criteria for either the size of the gas units or their utilization rates leads to small increases in hydrogen demand as more gas units are covered by the GHG proposal.

If capital expenditures equivalent to 20% of a new combined-cycle unit are needed to cofire hydrogen, its use declines to around 0.1 quadrillion Btu. If low-priced gas is available (around $2/MMBtu), there is also a significant drop in demand for hydrogen at $3.7/MMBtu ($0.5/kg). Were hydrogen prices to rise to $1/kg ($7.4/MMBtu), all demand for hydrogen is eliminated. Reducing the availability of renewables through siting restrictions (setbacks, land exclusions, or perhaps local opposition) increases the need for hydrogen as additional gas generation is used to offset lower generation by renewables. Conversely, the availability of lower-cost and more efficient renewables means less gas generation is needed, and therefore less hydrogen.

The final three sets of results involve DIEM scenarios in which the necessary hydrogen is supplied through electrolysis (e.g., GHG + H_2 electrolysis). If the electricity used for this hydrogen production comes from renewables that otherwise would have been available

[20] Note that the data developed in the EPA analysis, however, do not necessarily include hydrogen consumption by existing gas units since they were handled through offline calculations.

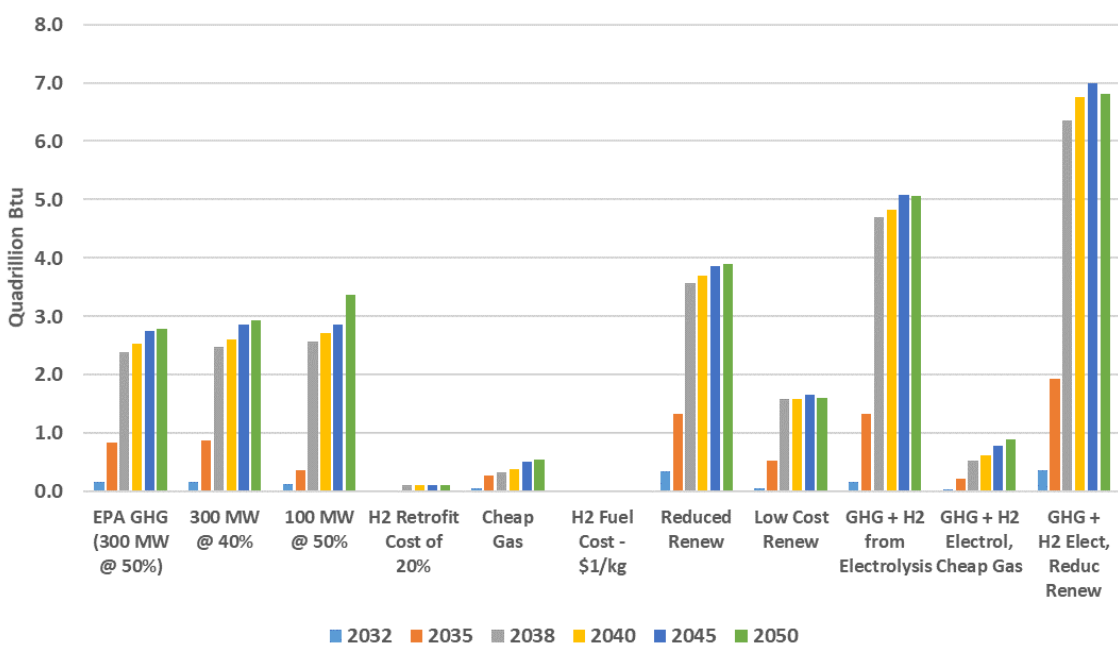
[21] For comparison, natural gas use in electricity generation was around 12 quadrillion Btu in 2022.

to generate for the grid, the system will need to add to add additional resources—whether renewable or fossil—to meet the original demands from customers. If additional gas generation is used to provide for this demand, these gas units will also be subject to GHG proposal requirements for hydrogen cofiring (or CCS), which potentially leads to even more demand for hydrogen. If this new hydrogen is also supplied through electrolysis, additional generation will be needed, and so forth until an equilibrium is established that balances fuel used for grid generation with the electricity needed for hydrogen electrolysis.

First, compare the main EPA GHG results on the left side of Figure 10 (where hydrogen comes from outside the electricity system or perhaps from renewables that would not have been otherwise suitable for generating for the grid) to those in which the necessary hydrogen is produced through electrolysis (GHG + H_2 on the far right) using resources that otherwise could have supplied demands on the grid. The implication of the observed increase in hydrogen demand is that at least some of the additional generation needed to offset the electrolysis requirements comes from gas generation, which eventually leads to a possible doubling in hydrogen demands as all the feed-back loops are accounted for.

In other electrolysis cases, such as the Cheap Gas scenario, where the initial demand for hydrogen is comparatively low, producing hydrogen from electrolysis (GHG + H_2 Electrol, Cheap Gas) does not necessarily lead to feedback requiring large amounts of additional hydrogen. On the other hand, if the availability of renewables is limited in some fashion, producing hydrogen through electrolysis is likely to lead to even more gas generation, which then leads to even more hydrogen demand, which then requires more electrolysis—with this circular flow implying potentially significant increases in the necessary generation and associated hydrogen demands.

Figure 10. Hydrogen demand by gas turbines under the EPA GHG proposal



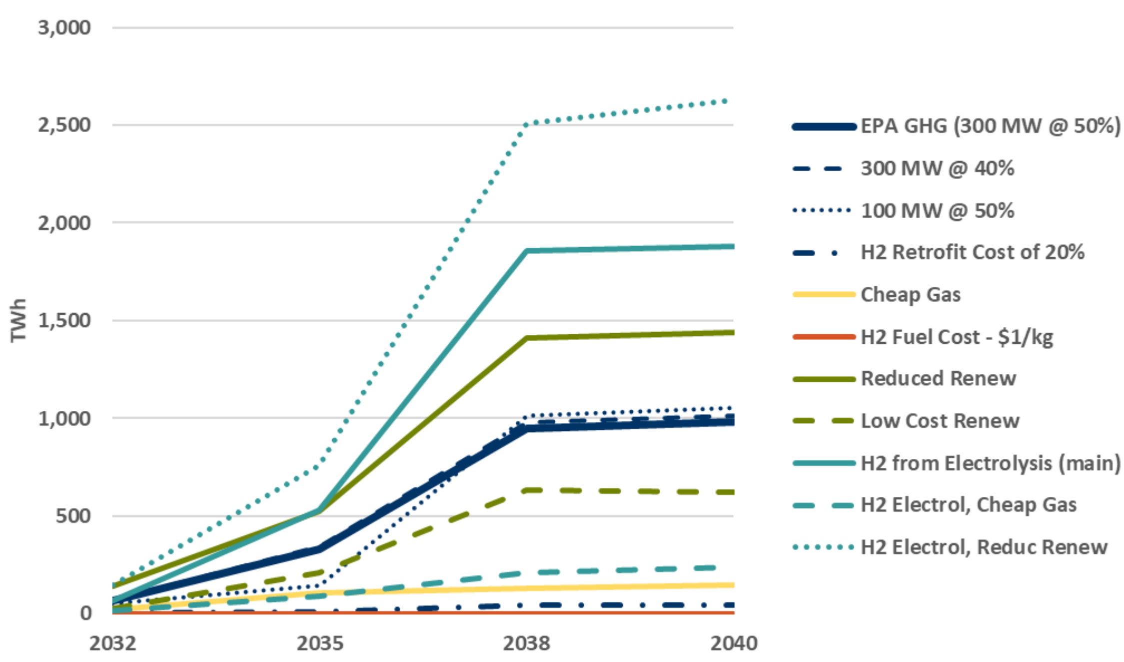
Source: DIEM model

Figure 11 looks at the implied electricity needed for electrolysis in the first eight scenarios from Figure 10 (but without any feedback loops that might lead to additional electricity and thus hydrogen demands, or any price impacts on delivered hydrogen costs). Data from NREL (2022b) assume that the efficiency of hydrogen electrolysis starts at around 73% in 2032 and improves to 77% by 2050.[22] Converting the hydrogen demands from Figure 10 into the implied amount of electricity needed for the main EPA GHG scenario gives slightly less than 1,000 TWh of energy needed to produce that amount of hydrogen through electrolysis. Starting from an initial demand from the grid of around 4,500 TWh in 2038, producing the hydrogen through electrolysis would require an increase in generation of around 20%. Some of the other eight cases with limited hydrogen demands imply significantly less in terms of electricity equivalents.

However, the impact of limiting renewables and the associated feedback implied by the additional gas generation could lead to larger increases in electricity needed for hydrogen electrolysis. Incorporating the electrolysis feed-back within the modeling of the electricity system results in even higher electricity demand—the H_2 from Electrolysis (main) case. Finally, incorporating the feedback with potential restrictions on renewables gives the highest amounts of electricity needed for electrolysis—H_2 Electrol, Reduc Renew.[23]

The following section provides additional details on the DIEM model, assumptions, data, and descriptions of how the IRA and GHG proposal scenarios are modeled. After that, the

Figure 11. Potential electricity generation needed for hydrogen electrolysis



Source: DIEM model

[22] The energy content of hydrogen is 39.4 kWh per kg (in higher heating value).

[23] It is assumed in the modeling that any electrolysis occurs in the same state where the hydrogen is needed.

results section first discusses IRA findings, followed by additional features of the EPA GHG proposal findings.

MODEL STRUCTURE AND DATA

This analysis is conducted with an updated version of the Dynamic Integrated Economy/Energy/Emissions Model (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 IPM (EPA 2023g) and NREL ReEDS (2022), 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, Ross and Murray (2016). DIEM was also used throughout the North Carolina Clean Energy Plan stakeholder process (Konschnik et al. 2021) and 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).

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

- **Annual Energy Outlook (AEO) 2023:** Electricity demands by region, wholesale fuel prices, costs and characteristics of non-renewable generation technologies. Demand and prices are from the No-IRA and the Reference Case (With IRA) forecasts in AEO 2023 (EIA 2023a).
- **National Renewable Energy Laboratory (NREL):** NREL ATB forecasts for renewable and battery storage costs and efficiencies (NREL 2022, 2023b); NREL ReEDS Standard Scenarios (2022) for renewable resource availability by location and costs to connect to the grid, efficiency of hydrogen electrolysis technologies (NREL 2020 and 2022b), along with 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 2023e]); IPM documentation on power sector modeling (operating costs and availability of existing units, hourly electricity demands by region, hourly wind and solar generation, costs of retrofitting existing units with CCS, costs to transport and store carbon dioxide [EPA 2023d, 2023c]).

With regards to the IRA and EPA GHG proposal in this analysis, the most important assumptions and data include the following:

- Natural gas prices from the AEO and EPA IPM models.
- Renewables availability from the NREL Mid case and Reduced Renewables cases, and potential short-term cost adders for quick installation from the EPA IPM model.
- CCS retrofit costs from the EPA IPM model. For coal plants, these have capital costs of $1,900 to $2,600/kW, capacity penalties of 28% to 34%, and heat rate penalties of 38% to 50%. For gas combined-cycle units, the CCS retrofits have capital costs of $1,000 to $1,400/kW, capacity penalties of 15% to 19%, and heat rate penalties of 18% to 24%. Capital costs decline modestly over time through experience gained under the IRA (5% in 2028, 10% by 2035, and 15% by 2040).
- CO_2 transport and storage from the EPA IPM model.
- Costs of long-distance transmission lines from NREL and the EPA IPM models.
- Battery reserve margin bounds and contributions from the EPA IPM model.
- Reliability constraints from NREL.
- Hydrogen production technologies from NREL.

Sensitivities on Assumptions

Several types of assumptions about data and forecasts can have particularly significant influences on estimated policy outcomes. Rather than provide a general range on estimate policy findings, it can be more helpful to examine variables individually in order to evaluate the importance of specific assumptions. This section discusses some of the main sensitivity analyses run on a range of data.

Renewables Costs

As is reflected in recent NREL ATB forecasts (see Table 2), the costs of building have been increasing for a variety of reasons. Given the size of these increases compared to the values of the investment and production tax credits provided in the IRA, two alternative scenarios are examined:

1. **DIEM Standard Assumptions:** The updated assumptions in DIEM use the overnight capital equipment and financing costs from the latest NREL ATB 2023 forecasts—in most instances, costs are from the NREL Moderate technology case that is shown in Table 1. In addition to these capital costs, the modeling also includes other new features in the ATB 2023: improved capacity factors for wind and also solar panels (based on using bifacial PV modules), increased size of batteries associated with the combined solar plus battery technology option, and adjusted O&M costs based on battery lifetimes and other factors.[24]
2. **IRA (ATB 2022):** The ATB 2022 technology forecast of overnight capital costs, which underpins many previous IRA analyses, is modeled as a counterpoint to the new

[24] Offshore wind costs in the ATB 2023 were essentially unchanged from the ATB 2022.

ATB. Forecasts of interest rates and financing costs are still based on the ATB 2023, which has rates that are several percentage points higher than the previous forecast. A Low Renewables Cost scenario was also investigated based on the NREL Advanced technology case, which has significantly lower cost projections for renewable units. These costs are again higher than they were in the ATB 2022 forecasts.

3. A Low Renewables Cost scenario was also investigated based on the NREL Advanced technology case, which has significantly lower cost projections for renewable units. These costs are again higher than they were in the ATB 2022 forecasts.

Fossil Fuel Prices

The standard assumptions in DIEM regarding fossil fuel prices are based on combining wholesale price forecasts from the AEO with transport costs from EPA's IPM model (plus seasonal adders in the case of natural gas). This provides a specific fuel price estimate for each fuel and regional/seasonal combination, regardless of the demand for fossil fuels. Variations in the wholesale price component can be varied using the macroeconomic component of the DIEM model, which covers economy-wide demands for fuel along with estimates of the supply elasticities of fuel supplies. This, however, makes it hard to evaluate the results if fuel prices are changing along with all the other variations being investigated across scenarios. Consequently, most cases rely on point estimates for fuel prices. This assumption has less influence than in the past on results as renewables continue to expand their share of generation with an accompanying decline in fossil generation. However, alternatives to these assumptions are investigated.

The alternative forecasts and methods of representation include (in order of the extent to which they are used in subsequent model results):

1. **DIEM Standard Approach:** In the standards assumptions used in DIEM, wholesale coal and gas prices from the AEO Reference Case (or side cases)[25] combined with EPA IPM data on transport costs and seasonal adders.[26] In Figure 12, the gray shaded area around the DIEM – IRA average trend line shows the annual regional variation in these gas prices (but not any additional seasonal variation that would expand these bands). This area can be examined for potential overlap with the assumed hydrogen price in certain policy scenarios—where the hydrogen price shown comes from the EPA RIA for GHG.
2. **Cheap Gas:** These retail prices are taken from EPA's IPM model results for their Pre-IRA and Post-IRA cases (EPA 2023g and 2023f, respectively). The SSR Excel sheets in EPA's provided zip files have point estimates for average delivered natural gas prices by region and season. These gas prices average around $3/MMBtu for the Pre-IRA

25 The AEO side cases are used less than in some previous DIEM analyses merely because the other alternative price forecasts provide a wider range of outcomes for comparison. However, the AEO High Oil/Gas Resource case is used to provide an AEO Low Gas Price alternative in some model runs.

26 Other alternatives, aside from wholesale prices based on the AEO side cases, include using delivered retail prices from the AEO Reference Case and side cases, at either the census region or National Energy Modeling System (NEMS) electricity market region levels.

Table 2. NREL annual technology baseline: Overnight capital costs (Moderate Case), 2023 versus 2022 (in $2020)

Technology		2023	2030	2032	2040	2050
Onshore wind	ATB 2023	$1,305	$1,037	$1,016	$935	$833
	ATB 2022	$1,258	$913	$895	$822	$730
	% Increase	4%	14%	14%	14%	14%
Solar PV*	ATB 2023	$1,230	$959	$882	$705	$584
	ATB 2022	$1,049	$734	$721	$669	$603
	% Increase	17%	31%	22%	5%	-3%
Solar PV + battery**	ATB 2023	$2,044	$1,523	$1,432	$1,190	$980
	ATB 2022	$1,690	$1,042	$1,021	$939	$836
	% Increase	21%	46%	40%	27%	17%
Battery (4 hour)	ATB 2023	$1,642	$1,152	$1,117	$974	$797
	ATB 2022	$1,256	$895	$873	$783	$671
	% Increase	31%	29%	28%	24%	19%

* The NREL ATB 2023 now assumes the use of bifacial modules, which increases capacity factors.

** The battery component has been upgraded from 50 MW (AC) to 60 MW (AC). Roughly adjusting for battery size gives a percent increase in capital costs of 25% in 2030. O&M costs (not shown) now account for full replacement of the battery component every 15 years.

Notes: Other net capacity factors are also somewhat higher in ATB 2023 than in ATB 2022. Values for ATB 2023 converted to $2020 using BEA GDP deflator. Costs for offshore wind were not updated significantly between 2022 and 2023.

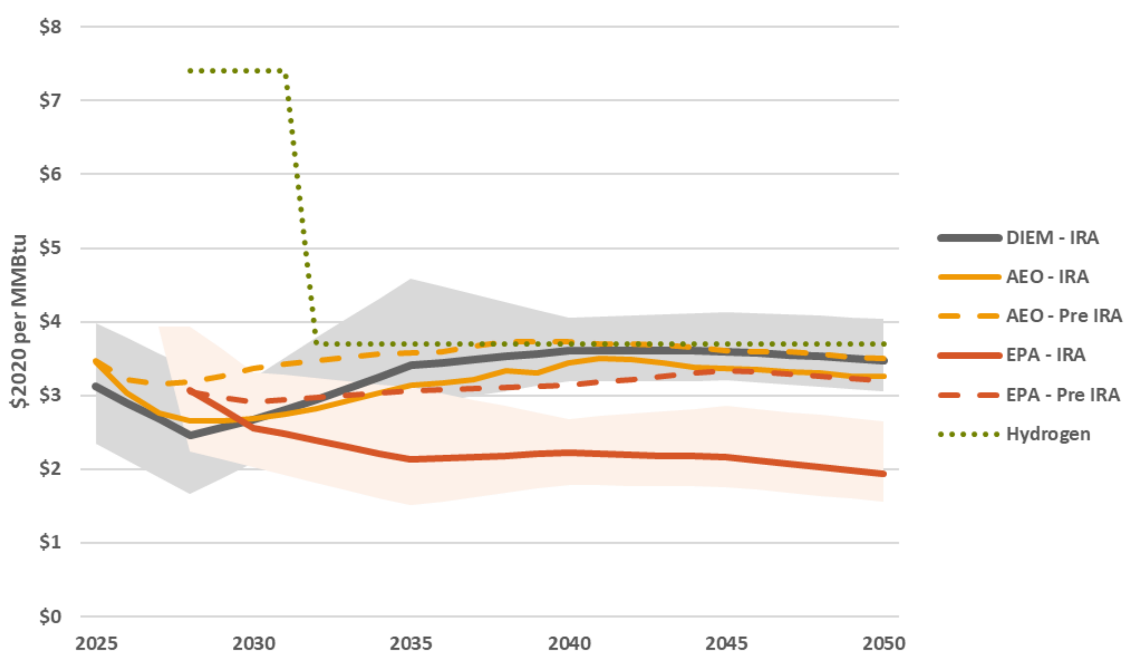
case and $2/MMBtu for the Post-IRA case (see the EPA Pre-IRA and EPA IRA lines in Figure 12), where the orange shaded area shows the regional (but not seasonal) variation in these prices for comparison to the assumed hydrogen prices. In these runs, this approach to natural gas prices is combined with the DIEM standard estimates for coal prices. Because natural gas likely has a larger role than coal in the policies analyzed here, this IPM-related Cheap Gas case is used as the main alternative to the DIEM approach in sensitivity cases.

3. **Cheap Fossil Fuels:** These prices are based on including the complete fuel supply curves for coal and natural gas from the IPM model used in the EPA analyses (EPA 2023d, 2023c). These supply curves, unlike the point estimates in options 1 and 2, have the potential for some coal and gas to be available at very low prices, and the fuel prices increase from there as additional fossil fuels are used for generation (although the final delivered prices can remain quite low, as seen by the $2/MMBtu delivered price for natural gas in the Cheap Gas logic).

In spite of the effects of renewables tax credits under IRA, natural gas generation may remain a cost-competitive alternative; however, this depends even more on expected gas prices than in past analyses. A range of potential gas price forecasts are investigated in this paper as they seem to be a main driving factor in explaining differences in outcomes across models looking at the IRA. This will also be the case for investigations of EPA's GHG Proposal. If delivered hydrogen is more expensive than natural gas (after consideration of IRA credits), turbine units will attempt to avoid the fuel. This will potentially influence which combined-cycle units will operate, given the current size specification of 300 MW for hydrogen cofiring requirements. However, if hydrogen is cheaper than natural gas, affected generators will be more willing to operate, regardless of size or utilization rate requirements. (The analysis assumes that units meet—but do not exceed—the hydrogen percentage requirements for cofiring to allow a more consistent comparison of the findings across scenarios where the hydrogen price is lower or higher than the gas price.)

Figure 12 shows some of the potential alternative forecasts that can be considered with a comparison to the hydrogen prices used in EPA's NSPS. The delivered prices are weighted by consumption of gas by generators across the nation, which obscures regional variation that may place local prices above or below certain levels, such as the hydrogen price. The standard assumption in DIEM is to start with the wholesale Henry Hub gas price from the AEO forecasts and then add regional transport adders and seasonal costs to the wholesale price to get a delivered price (on average, there are only small differences between the Henry Hub and delivered price for generators nationally—this can, however, vary significantly by region and time of year). Combining these prices with the gas generation pattern in the DIEM IRA forecast gives an average price that is higher than the average AEO delivered prices and can, for some regions, place the gas price above the hypothesized hydrogen price. This analysis also considers lower gas-price forecasts as alternatives such as the delivered prices from EPA's IPM analysis of IRA (EPA – IRA). Emissions differences and generation decisions can vary significantly across assumptions.

Figure 12. Delivered natural gas price assumptions



Sources: DIEM model, AEO 2023 Reference Case and No-IRA (EPA 2023g); EPA IPM Pre-IRA and IRA (EPA 2023f)

Renewables Availability

Along with the basic construction costs for renewables from the NREL ATB forecasts, installation of renewables depends on the availability of site-specific renewables resources, the efficiency of renewables at that site, the costs of connecting the site to the grid, and the overall ability of the system to build or otherwise incorporate new renewables. As noted in a recent Lawrence Berkeley National Laboratory study (LBNL 2023), there are more than 2,000 gigawatts (GW) of potential new generation and storage projects in the queue to be approved for interconnection with the grid, including 947 GW of solar, 680 GW of storage, and around 300 GW of wind (onshore and offshore). While many of these projects will not advance beyond the proposal stage, it can take several years for successful projects to navigate this process. Examining a range of options for renewables can provide a sense for how policy results from the model may be influenced by different assumptions.

The alternatives discussed in the subsequent results include:

1. **DIEM Standard Assumptions:** As discussed previously, DIEM uses data from the NREL ReEDS model that generates the NREL Standard Scenarios (Gagnon et al. 2022) for the availability of renewable resources by location and the costs of connecting locations to the grid. These assumptions are based on the NREL Mid case inputs for technology costs.

2. **Reduced:** This is based on NREL's Reduced case supply curves for wind and solar PV, which are more limited in scope as the result of additional setbacks and land exclusions when calculating the availability of renewable resources (NREL 2022). These adjustments reduce the potential technical (rather than economic) supply of wind and solar by 50% to 70%. As will be demonstrated in some of the model results, these land exclusions on renewable resources are not necessarily uniformly distributed around the country.

3. **More Reduced:** The resource availability from the NREL Reduced supply curves for wind and solar PV are reduced by 50% to explore potential implications of more significant limits on renewables, whether from more expansive exclusion zones or local opposition. Costs of connecting the remaining resources are the same as estimated in the NREL Reduced scenario.

4. **Quick Build Costs:** These model runs incorporate EPA IPM data (see Table 4-13 in EPA 2023c) on short-term capital cost adders. These adders, imposed through 2035, increase construction costs through a stepped supply curve to reflect potential short-term competition for building resources if the system attempts to quickly expand new generation. These supply curves are most relevant for wind and solar PV, where the first step allows around 20 GW of solar PV, 25 GW of onshore wind, and 5 GW of offshore wind annually at the base unit price. Depending on the year and location, the second step of the supply curve increases construction costs by 20% to 30%, effectively removing most savings from IRA tax credits.

Electricity Demand Growth

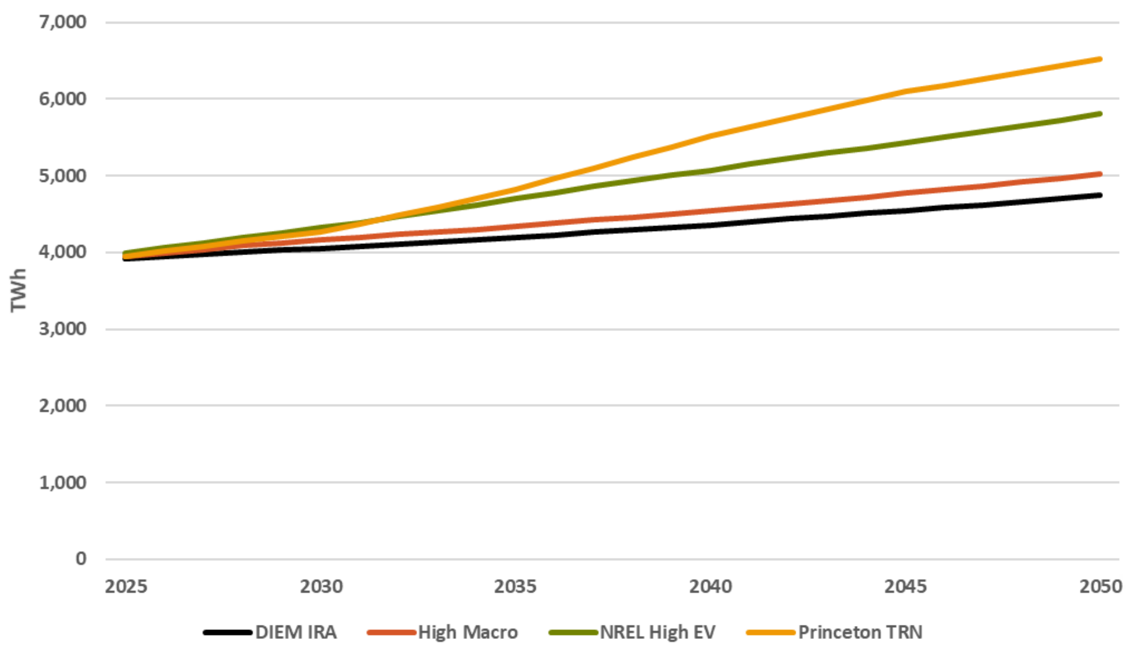
Growth in electricity demand is always a controlling factor in determining how much new capacity will be needed to meet future demands. The IRA contains features that will both increase and decrease demand for electricity over time. Incentives for energy efficiency will lower demand, while others that spur electric vehicles and other types of electrification will raise demand. The AEO forecasts that are typically used in the DIEM model suggest that these countervailing impacts may largely offset each other. To explore alternative outcomes, several cases are examined in this analysis:

1. **DIEM No IRA:** Regional electricity demand growth comes from the AEO No IRA side case.
2. **DIEM IRA:** Regional demand growth comes from the main AEO Reference Case (0.7% average annual growth over 2022-2050). These growth rates are quite similar to the AEO No IRA case (not shown in the figure).
3. **High Macro:** Regional growth comes from the AEO High Economic Growth case (0.9% annual growth over 2022–2050, where overall demand in 2050 is 5.5% higher than in the AEO Reference Case). Given the minor differences from the DIEM IRA case, this alternative is only presented sparingly in the results.
4. **NREL High EV:** This case starts with the AEO Reference Case electricity demand (minus AEO estimates of EV usage) and adds additional demand growth from the NREL Electrification Futures Study (NREL 2018) for their High EV Adoption case. Sales of EVs expand rapidly from today's levels to make up around 60% of all light-duty vehicle (LDV) sales by 2030 and increase linearly from there to represent 95% of LDV sales by 2050. In 2032, EVs use 360 TWh of electricity, which grows to around 1,000 TWh by 2050 (a 9% and 22% increase in total demand, respectively).
5. **Princeton TRN:** This case includes Princeton's total estimated electricity demand by all transportation modes, including categories beyond light-duty electric vehicles, from the Princeton Net-Zero America analysis (Jenkins et al. 2021) as an alternative forecast for electricity demand. In 2032, the transportation sector is forecast to use 380 TWh of electricity, which grows to more than 1,700 TWh by 2050 (a 9% and 37% increase in total demand, respectively).

Additional Sensitivity

An additional sensitivity is also briefly discussed where the results are helpful in illustrating how alternative assumptions may drive model findings. This scenario examines the impacts of transmission costs on the solution, using an investment tax credit as a proxy for potential differences in cost assumptions across models. The standard assumptions in DIEM use NREL transmission data for existing capacity and the costs of new lines. NREL assumes new AC lines cost around $3,300/MW-mile and have losses of 1% per 100 miles. NREL assumes DC lines cost 40% of comparable AC lines and have losses of 0.5% per 100 miles, but require AC/DC converters on each end of the line at $140,000–$180,000/MW. According to the author's calculations, the IPM model appears to have line costs around $1,800/MW-mile (or roughly 55% of the NREL AC lines). To proxy potential variations, the modeling looks at the possibility of extending the IRA investment tax credits of 30% to new transmission lines.

Figure 13. US total electricity demand scenarios, including transport electrification



Source: Author's calculations used in the DIEM model

SCENARIO DESIGN

This section discusses the four alternative policy forecasts considered in modeling the IRA and its potential interactions with EPA's GHG Proposal. In some cases, more than one policy variation are examined, along with the range of sensitivity cases across assumptions.

Policy Scenarios

Analysis of policy scenarios related to the electricity industry begins by establishing a baseline forecast against which changes can be evaluated. Under the current circumstances in which IRA is enacted legislation, a baseline or reference case forecast without the IRA is less relevant than typically the case, however, some insights can still be gained by presenting No IRA forecast estimates. Contrasting these modeling results with model runs of the IRA and also the EPA GHG proposal shows the relative impacts of the two policies. Core components of the four cases include:

1. ***No IRA* Reference Case:** This case includes federal and state policies (including Build Back Better legislation) in place prior to passage of the IRA. This scenario assumes the following:
    a. Electricity demand growth from the AEO 2023 No IRA case.
    b. Wholesale natural gas and coal prices from the AEO 2023 No IRA case.

2. **Inflation Reduction Act (*IRA*):** The model includes the production tax credits (PTCs) and investment tax credits (ITCs) specified in the legislation for various types of electricity generation but does not estimate impacts outside of the electricity sector. Impacts in some areas such as electric vehicles are explored through the sensitivity analyses on demand growth. The main policy assumptions include the following:

    a. AEO 2023 estimates of economy-wide improvements in electricity efficiency, as well as increased demand from EVs and other industrial electrification. However, in the AEO, these two counterbalancing forces largely offset each other, leaving electricity demand similar to the AEO No IRA case.

    b. AEO 2023 estimates of wholesale natural gas and coal prices. Unlike electricity demand, wholesale gas prices are significantly lower in the AEO Reference Case including IRA.

    c. PTCs for onshore wind, geothermal, and landfill gas are assumed to be $25/MWh for the first 10 years of operation. This includes a fivefold bonus for meeting wage and apprenticeship requirements in the IRA. No additional credits are provided for locating in energy communities or using domestic content (potentially adding an additional 10% to the PTC value for each condition).

    d. ITC for solar PVs, new nuclear, and battery storage of 30%, which includes the fivefold bonus for labor conditions.

    e. PTC for existing nuclear of $15/MWh through 2032, which is discounted if wholesale electricity prices rise above $25/MWh.

    f. Carbon capture, use and sequestration credits are available to any retrofitted existing fossil units or new units that capture at least 90% of CO_2 emissions. Including a fivefold bonus for meeting labor requirements, these credits are assumed to be $60/ton for CO_2 used in EOR or $85/ton for sequestered CO_2. Direct air capture units receive $130–$180/ton of CO_2.

    g. Impacts of assumptions regarding clean hydrogen are based on EPA's Regulatory Impact Analysis of the GHG Proposal, discussed below in relation to modeling that policy proposal.

    h. Note: regardless of the final level of emissions, the IRA analysis does not impose the condition that tax credits expire if emissions fall below 25% of 2022 levels. Because this may or may not apply in all cases, it would be hard to compare findings across scenarios if the tax credits applied are not consistent across the range of model runs. Where this could be a factor can be seen in the illustrations of emissions trends that follow.

3. **Potential Extension of IRA:** These cases extend the IRA tax credits through 2050 to evaluate how emissions might continue to evolve and how close to—and when—the electricity sector might approach net zero. As with the IRA runs, the provision that tax credits expire based on the level of national emissions from electricity is dropped. Two alternatives are explored:

a. ***IRA Extended:*** This scenario extends all IRA tax credits listed previously through 2050.

b. ***IRA Extended Without Nuclear or CCS:*** This scenario extends all the IRA credits, except those for generation from existing nuclear plants or the credits for CCS, to better evaluate competition among and any potential tradeoffs between renewable generation and nuclear or CCS generation.

4. **EPA GHG Proposal (*EPA GHG or GHG*):** These cases examine potential interactions between the IRA and EPA's new GHG proposal. All GHG proposal scenarios include the impacts of IRA as a starting point. Basic assumptions and unit criteria are shown in Figure 14:

   a. **Combined-cycle units:** New units (presumably larger than 300 MW, based on the AEO assumptions for new units used in DIEM) are assumed to either adopt CCS or burn a minimum of 30% clean hydrogen by volume in 2032 and 96% in 2038.[27] The main run for existing units uses the 300 MW size and 50% utilization rate criteria. These are compared to 100 MW and 40% utilization assumptions to evaluate sensitivity. Although the DIEM model normally assumes that gas units converting to 100% hydrogen face costs associated with retrofitting their equipment, these costs are not applied during the main runs in this analysis for consistency with the EPA RIA approach. Hydrogen retrofit costs equivalent to 20% of the capital costs for a new combined-cycle unit are adopted in several scenarios for comparison (NREL 2020).

   b. **Combustion turbines:** New combustion turbines for peaking are not currently required to take action, based on realized utilization rates that are typically significantly lower than the 20% threshold in the EPA's RIA. Although units running more than 20% face hydrogen cofiring requirements, even in situations where hydrogen is cheaper than natural gas, this does not tend to be an option selected by the model (building a new combined-cycle is the preferred approach in the absence of any limitations on their construction). There are no requirements for existing simple-cycle turbines, which also run at less than 20% on average, even in the near term when it may be infeasible to install new generation (utilization rates are higher in the near term, compared to future years).

   c. **Coal plants:** Results from the GHG RIA (EPA 2023a) suggest that the two most likely outcomes are retirement or installation of CCS equipment. Accordingly, this preliminary analysis assumes that coal units will either retire prior to 2035 or will retrofit with CCS by 2035 (as opposed to 2030, the implementation year used in the EPA RIA). The modeling does not allow coal plants to avoid the NSPS requirements by doing a 100% conversion to a steam gas unit. It also does not consider the option of allowing plants retiring between 2032 and 2040 to delay other actions by choosing to cofire with 40% natural gas. These assumptions can be revisited in the future, but do not appear likely to alter the economics that suggest coal retirement will be the more cost-effective option for those plants

[27] CCS for gas units—whether new or retrofit—is not the preferred option in the model runs, so hydrogen is a de facto choice.

Figure 14. Criteria in EPA GHG proposal (sizes and timing from the EPA RIA [EPA 2023a])

New Gas Combined Cycle

Utilization Rate	H_2 Cofiring	CCS
<50%	30% in 2032	90% CCS in 2035
>50%	30% in 2032 96% in 2038	90% CCS in 2035

New Simple Cycle Turbines

Utilization Rate	H_2 Cofiring
<20%	Not Required
20% - 50%	30% H_2 in 2032

Existing Gas Combined Cycle

Utilization Rate	Size < 300 MW	Size > 300 MW
<50%	Nothing	Nothing
>50%	Nothing	30% H_2 in 2032 / 96% H_2 in 2038 90% CCS in 2035

Existing Simple Cycle Turbine

Utilization Rate	All Units
<20%	Nothing
20% - 50%	Nothing

Existing Coal

Size Criteria (>25 MW)

Retirement Date	Utilization <20%	Utilization >20%
Before 2032	No Increase in Emissions Rate	No Increase in Emissions Rate
Before 2035	No Increase in Emissions Rate	Not allowed
Before 2040	40% gas cofiring In 2030	40% gas cofiring In 2030
After 2040	90% CCS in 2030	90% CCS in 2030
Coal-to-Gas Conversion	No Additional Action	

Notes

Phase #1 is efficient turbines. The criteria in this figure focus on phases #2 and #3.

Base load are units running greater than 50% utilization rate, intermediate load are 20%-50%, and peaking are below 20%.

New Units – Defined as starting construction after 2023.

Existing NGCC – The RIA assumed 300 MW, but the size criteria may receive comments.

Simple Cycle – The utilization rate criteria of 20% may receive comments.

Existing Coal – Requirements are by retirement date for any coal units above 25 MW. In the IRA, the “Proposal” and “More Stringent” assumed 500 MW. The “Less Stringent” assumed 700 MW and smaller units avoided CCS with 40% H_2 cofiring.

that have chosen not to adopt CCS under either the IRA or this approach to modeling the GHG NSPS. The less-stringent RIA option is not analyzed, but the size requirement of 700 MW might make it somewhat more likely that gas cofiring could be a preferred option.

d. **Clean hydrogen:** Although the DIEM model includes technologies to produce hydrogen as part of its model runs, for this comparison to results from EPA's IRA, the analysis adopts the RIA assumption that hydrogen costs $1/kg before 2032 and $0.5/kg starting in 2032 ($7.4/MMBtu and $3.7/MMBtu, respectively, measured in higher heating values).

e. **Hydrogen Production:** Two alternative assumptions about the sources of clean hydrogen are considered in order to compare how hydrogen from electrolysis (with a resulting increase in electricity demand) may have different implications than hydrogen from other sources:

   i. The main ***EPA GHG*** (*or **GHG***) scenarios assume that hydrogen consumption does not affect total electricity demand. This would be the case for hydrogen produced from, for example, steam methane reforming with CCS. It is also possible, if somewhat less likely, that this clean hydrogen could be produced through electrolysis, but using methods that didn't—in any fashion—affect the renewable resources remaining available to produce electricity for the grid as a whole. While this might hold for small amounts of hydrogen demand, it is less plausible as hydrogen needs increase, either through the GHG Proposal or any potential future economy-wide net-zero policies.

   ii. The ***GHG + H_2*** electrolysis scenarios assume clean hydrogen is produced using generating resources that could otherwise supply electricity to the nation's grid. This can potentially increase the demand for electricity as a whole in the system, in part because electricity models do not typically assign a correspondence between the source of electricity and the use of that electricity. With the IRA in place, there will likely always be enough renewables in the system to assume that they can be directed toward producing clean hydrogen, if desired. However, the important assumption is whether or not these renewables would have been considered an economic choice in the absence of the need for clean hydrogen in the first place, in which case using them to produce hydrogen precludes them from supplying electricity to the grid more broadly.

f. As is discussed in the section on sensitivity analysis, the two policy options, GHG and GHG + H_2, for GHG Proposal are each explored under two particularly important sets of assumptions regarding natural gas prices and the availability of renewable resources:

   i. Natural gas prices – as shown in Figure 12, natural gas prices may be either above or below the assumed price for hydrogen in the EPA RIA, which is set at $3.7/MMBtu (delivered) in the analysis. The standard DIEM assumptions based on AEO wholesale gas prices combined with EPA IPM data on gas transport costs and seasonal adders have gas prices potentially higher than

$3.7/MMBtu for some regions in some parts of the year. In this circumstance, hydrogen will be the preferred fuel, regardless of any requirements imposed by the GHG Proposal. In contrast, the Cheap Gas scenarios (where the delivered seasonal price of natural gas comes from the EPA IPM model) have natural gas prices lower than the cost of hydrogen in many cases, leading to the opposite choice on gas versus hydrogen as the desired fuel. Model runs are also considered in which the delivered price of hydrogen remains at $1.0/kg, which is higher than any natural gas prices anticipated in the AEO forecasts.

ii. Renewables availability – the standard DIEM assumption is based on NREL's Mid-Case scenario for renewable availability. These results are compared with findings based on the assumptions in NREL's Reduced case that has additional limits on the sites available for development. Any limits on renewables can interact with the need for gas generation from hydrogen and, potentially, the ability to supply that hydrogen through electrolysis.

State and Regional Results

The DIEM model solves at the state level; however, in many cases it can be easier to illustrate important trends in the findings at a higher level of resolution. Figure 15 shows two alternative regional aggregation schemes used in this paper for presentation purposes to facilitate interpreting results.

MODEL RESULTS

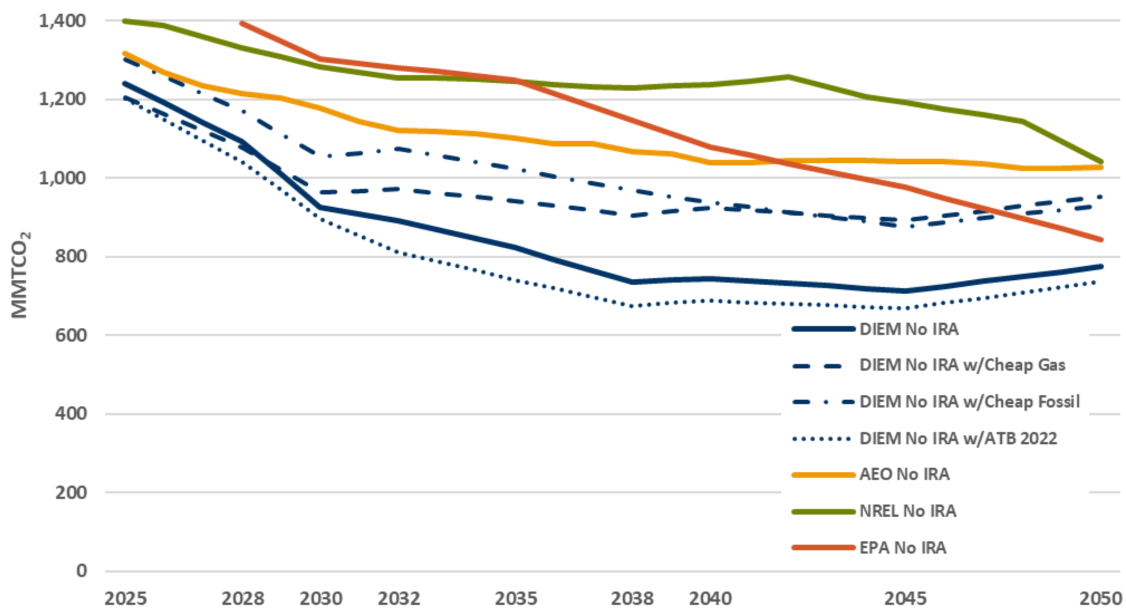
The first part of this section examines the emissions implications of the IRA under a range of alternatives, explores the investment decisions leading to the emissions outcomes, and then examines a number of additional factors of interest. Subsequently, the EPA GHG proposal is scrutinized in more detail.

Emissions

As will be discussed in this section, different models may disagree on emissions trends in the older No IRA scenarios, but tend to be in more agreement on emissions once IRA

Figure 15. Fifteen-region and five-region aggregations of state results for illustrative purposes

Figure 16. No IRA reference case emissions of CO_2 across models



Sources: DIEM model, NREL Standard Scenarios 2022 (Gagnon et al. 2022); AEO 2023 No IRA (EIA 2023a); EPA IPM Pre-IRA (EPA 2022b)

is considered, given the reduced influence of fossil fuel prices after IRA's incentives for renewables are included.

No IRA Emissions

Figure 16 contrasts emissions in the DIEM model in the No IRA case—using either DIEM's standard assumption of NREL's ATB 2023 or an alternative case with the ATB 2022—with similar results from several other previous analyses.[28] Highlights of the comparisons include:

- In the absence of the IRA policy, other models show only modest declines in emissions, in spite of expected declines in the costs of renewable generation, even though these analyses were conducted prior to the recent price increased estimated in NREL ATB 2023.

[28] The four models have different dynamic structures and therefore different solution years. EIA's NEMS model that generates the AEO forecasts is a recursive-dynamic model that solves a single year without foresight regarding future policy and market changes. The main version of NREL's ReEDS model is also recursive-dynamic but solves for even-numbered years. EPA IPM is a perfect-foresight model that anticipates future conditions and solves all years simultaneously, necessitating a more limited number of solution years (in this case, 2028 and then every five years starting in 2030). DIEM is also a foresight model and solves—in this case—for similar years, but adds in 2025, 2032, and 2038 for the investigations of EPA's GHG policy. The labels shown in Figure 16 are those for the DIEM solution years.

- Even without IRA, DIEM has more aggressive adoption of renewables, leading to lower emissions projections. This finding, however, depends on fuel-price forecasts and how the prices are represented in a model.
- Recent increases in renewables costs lead to 7% higher emissions on average in DIEM.

The standard assumptions in DIEM regarding fossil fuel prices—even though based on other forecasts—can vary significantly from other modeling, depending on how prices are incorporated into a model. This can potentially lead to substantially lower emissions forecasts in some DIEM runs. For example, coal mine-mouth prices in the slightly older AEO 2022 forecast, which underlies the NREL Standard Scenarios 2022 (Gagnon et al. 2022), are around 30% lower than those from Energy Information Administration (EIA)'s updated AEO 2023 forecast in its No IRA case. Similarly, the higher emissions in EPA's No IRA case are influenced by its comparatively low prices for natural gas, illustrated above in Figure 12 (even before accounting for the roughly 35% reduction in gas prices caused by IRA in the EPA analysis).

The potential range of emissions responses to such fuel-price forecasts is shown by running two alternative sets of assumptions in DIEM—Cheap Gas and Cheap Fossil (based on EPA IPM data, instead of DIEM's standard data from the AEO 2023 forecast). As discussed, the Cheap Gas case uses IPM's delivered retail prices and the Cheap Fossil case incorporates the full coal and gas supply curves that have initial supplies of fuel available at very low prices. Either of these options for representing fuel prices move emissions in DIEM much closer to those seen in other No IRA studies.

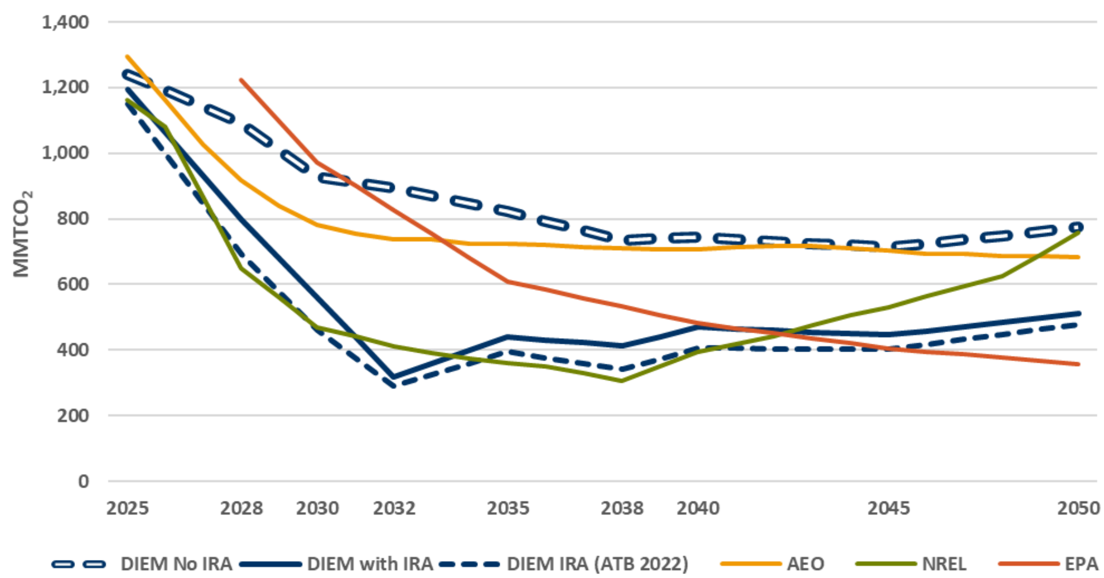
IRA Emissions

Figure 17 shows emissions across IRA analyses from the same modeling groups. Highlights include:

- IRA tax credits for renewables bring some model estimates of emissions closer together as the influence of fuel price assumptions is lessened.
- DIEM uses information on renewables costs and availability from the most recent NREL Standard Scenarios 2022 (Gagnon et al. 2022), and emissions forecasts between the two models are quite similar (note that the NREL estimate of emissions uses renewables costs from the ATB 2022).
- DIEM's estimated emissions are 13% higher on average, once recent increases in renewables and financing costs are included in the analysis—DIEM with IRA versus DIEM IRA (ATB 2022).
- The AEO and EPA analyses have comparatively more conservative estimates of emissions reductions both before and after IRA implementation, with the AEO suggesting very little decline in emissions over time once the IRA has been fully implemented regardless of continuing decline in renewables costs (AEO forecasts show solar PV costs declining by around 23% from 2032 to 2050, while onshore wind declines by 13% and offshore wind drops by 26%).

Inclusion of the IRA tax credits in the analyses reduces the impact of alternative fuel price forecasts and brings emissions somewhat closer together across models, compared to

Figure 17. IRA emissions of CO_2 across models



Source: Author's calculations used in the DIEM model

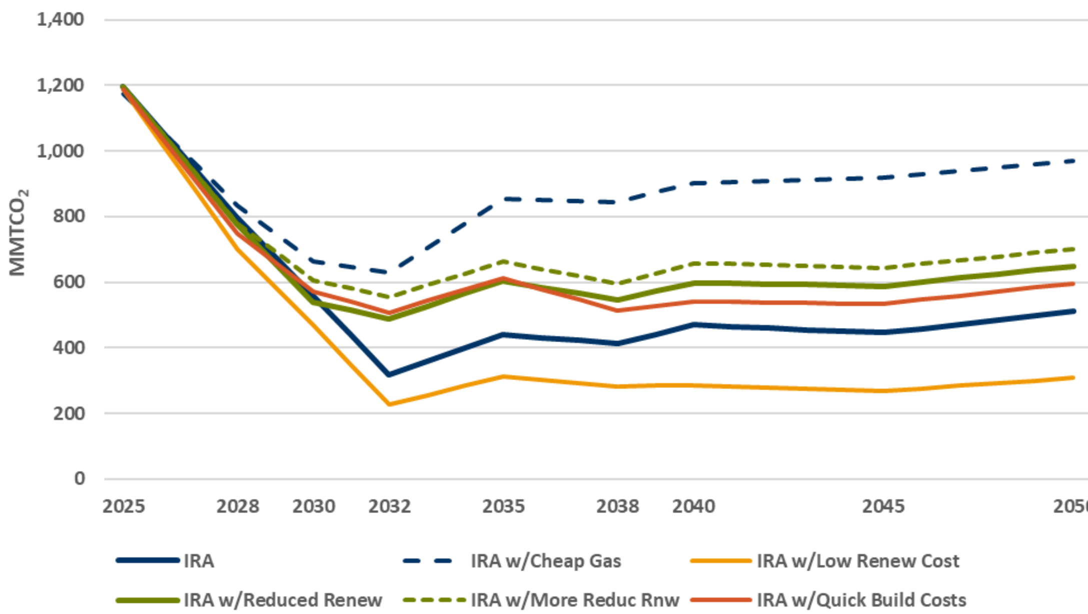
the No IRA cases (even in the absence of additional coordination on how fuel prices are represented). Given that the standard assumptions in DIEM use data on renewables from the NREL ReEDS model, it is not surprising that these two results are quite similar, particularly if both models are using the ATB 2022 cost forecasts. The AEO and EPA forecasts show more limited impacts on emissions from the IRA even though EPA's IPM model uses NREL renewables data (these data are, however, from older NREL forecasts than those in NREL's 2022 estimates).

Both the DIEM and NREL results suggest that emissions could potentially fall to a level that would trigger suspension of IRA credits, although this depends in DIEM on the specific assumptions used, where the trend shown in Figure 17 is lower than in the sensitivity analyses illustrated in the subsequent graph. Timing of emissions reductions can also change from year to year, depending on factors such as retirements of nuclear plants when IRA credits expire after 2032 or the pattern of retirements in coal plants, including those that might initially retrofit with CCS as the result of IRA. Both DIEM and NREL suggest that these factors can potentially lead to an increase in emissions after 2032. In the NREL results in particular, the influence of cheap fossil fuels re-exerts itself more strongly after the end of IRA and emissions begin to rise again.

Results from this point forward in the paper focus solely on findings from the DIEM model. Figure 18 looks at the sensitivity of emissions projections in DIEM to alternative assumptions regarding fuel prices and renewables availability. Highlights of the sensitivities include:

- If the availability of renewables is limited, emissions can stay well above 500 $MMTCO_2$.

Figure 18. Sensitivity of IRA emissions to modeling assumptions (DIEM model)



Source: DIEM model

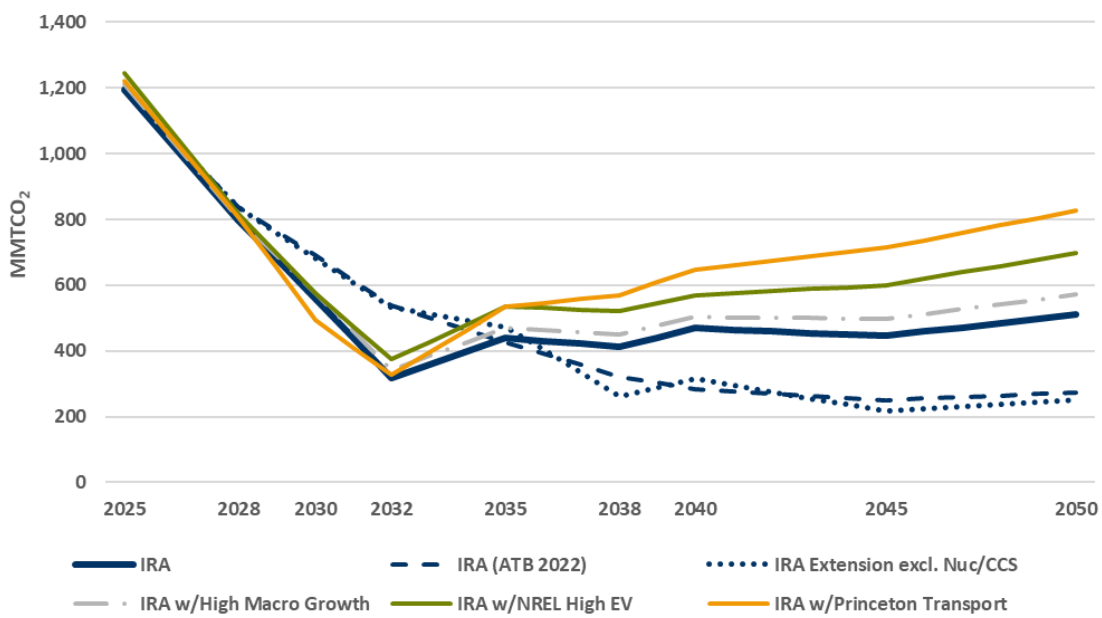
This is true whether the restrictions are on the availability of sites for development (Reduced Renew and More Reduced) or on the ability of the system to quickly expand the construction of renewables (Quick Build Costs).

- Low-priced natural gas can result in future emissions that are substantially higher after 2032. Lower prices for coal, as in the Cheap Fossil case (not illustrated), do not have much additional influence since coal is a small part of the generation fleet.

Unlike the main IRA case where emissions can potentially fall below 25% of 2022 levels, possibly leading to an end of IRA credits even if emissions rebound later, more limited opportunities for renewables keeps emissions above 500 $MMTCO_2$ (well over the cutoff trigger of roughly 375 $MMTCO_2$ level, based on AEO data for 2022 that shows 1,507 $MMTCO_2$ from the electric power sector). Limits on renewables availability imposed in the Reduced case raise emissions by around 130–170 $MMTCO_2$ per year, compared to the standard IRA scenario where higher levels of potential resources are made available. An additional 50% reduction in these resources in the More Reduced case leads to a further 50–65 $MMTCO_2$ of emissions per year. Similarly, the assumption that capital costs escalate with rapid installation of wind and solar (Quick Build Costs) leads to a similar level of emissions in the future as it is difficult to take full advantage of the IRA tax credits while they are still available. These cost escalations have a particularly significant limiting effect on renewables construction between 2030 and 2032, just as installations are attempting to quickly ramp up.

The figure also looks at emissions for an alternative fossil fuel price forecast, which may be more representative of the assumptions used in other analyses. The Cheap Gas scenario,

Figure 19. Sensitivity of IRA emissions to policy options and demand growth (DIEM model)



Source: DIEM model

which relies on delivered gas prices from the EPA IRA analysis, has the highest emissions of any of the model runs in the graph. Once the initial decline from IRA is past, future emissions rise as new capacity focuses on fossil units and there is an expansion in fossil generation from both existing and new units.

Figure 19 contrasts DIEM's main IRA emissions forecast to several alternatives. Highlights from these options include the following:

- Significant increases in electricity demand from electrification of transportation can lead to more emissions from generation, but they remain at levels well below today's emissions (even before accounting for emissions savings from removing conventional vehicles from the roads).
- Modestly higher demand from higher economic growth has fairly limited influence on emissions.
- Extending the IRA tax credits (if anticipated today) leads to less pressure in the near-term to install renewables quickly before the credits expire in 2032 and lowers emissions overall.

Extending the IRA tax credits, with or without the credits for nuclear and CCS, leads to lower emissions through 2050 as the expansion in renewable generation continues beyond the end of the current IRA program. This avoids the increase in emissions seen after the main IRA credits expire, where nuclear retirement after 2032 could potentially lead to construction of new fossil generation. The emissions trends also show an inclination for an IRA extension to reduce pressure to take advantage of renewables credits by 2032, which can result in slightly higher emissions in the near term as the time period over which renewables are installed is extended.

Emissions trends suggest that expanded electricity demand from the transportation sector may increase emissions over time as additional generation is required. The extent of these increases—in the absence of additional policies to reduce the carbon intensity of generation—will depend on the mix of new renewable and fossil generation that is built to supply electrification needs, discussed below.

Capacity Changes Under the IRA

Figure 20 contrasts No IRA and With IRA annual capacity changes for the time periods in the DIEM model.[29] Results for the With IRA cases are given for two alternative sets of renewables costs—DIEM's standard set based on the current ATB 2023 (IRA) and a set based on the previous year's lower costs from the ATB 2022. Highlights in the findings include:

- IRA accelerates renewables significantly through 2032, regardless of assumed costs.
- Installation of onshore wind represents the largest share of early installations, with solar accelerating toward the 2030-2032 time frame.
- Higher estimates of construction and financing costs—represented by the ATB 2023—shift the mix toward wind and away from solar and especially away from battery storage, whether as stand-alone batteries or combined jointly with solar PV installations.
- Only one-third as many (or fewer) new combined cycle units are needed because of IRA, and around one-half of the anticipated nuclear retirements are delayed until after IRA expires.
- Higher battery costs in the ATB 2023 lead to installation of additional combustion turbines for reliability, compared to the ATB 2022 data that had lower cost estimates.
- Once the IRA ends, some new renewables continue to appear as future construction costs decline, but most renewables build during 2030–2040 are timed to take advantage of the IRA credits. Eventually, continuing cost declines over the decade lead to more solar installations. The mix of new units is likely to emphasize turbines as a source of reliability rather than batteries.

The first time period shown (2020–2025) 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 2025, but most actions is already predetermined during past years or through ongoing construction or currently anticipated units, implying

[29] The No IRA case uses the higher renewables cost estimates from the ATB 2023. In none of these scenarios is the rate of capacity additions limited by constraints in the model, whether exogenously imposed or implied through the use of a capital cost sup-ply curve for rapid construction of new units.

few differences without and with IRA. If renewables costs are lower than currently expected, as was previously suggested by the ATB 2022, there is additional expansion in solar capacity.

The next few years (2026–2028) are where the IRA tax credits have some of the largest impacts as investors and utilities ramp up construction. If older legislation regarding tax credits had expired without the IRA (or because of any repeal of IRA), construction of renewables—particularly onshore wind—would have been delayed for several years as developers waited for expected future capital costs to decline toward 2030. In the No IRA case, combined-cycle units increase at a rate of more than 12 GW per year. With the IRA, onshore wind sees large advances over these early years. Nuclear retirements through 2028 are lower—but not zero—as the result of the IRA's $15/MWh production credits. Some new combined-cycle units are still added (around 4.8 GW per year in the IRA case) in anticipation of future growth, but fewer than without IRA. Lower renewables costs from the ATB 2022 would have led to only 1.5 GW per year of combined cycle as solar encompassed a much larger share of the new construction.

During the 2029–2030 time frame, onshore wind installations without and with the IRA credits are more comparable, but solar sees a significant expansion from the IRA. Total coal capacity is somewhat higher under IRA because 6 GW of coal have been retrofitted with CCS by 2030 (the first year it is assumed there are widely available options for the CCS retrofit along with CO_2 transport and storage).[30]

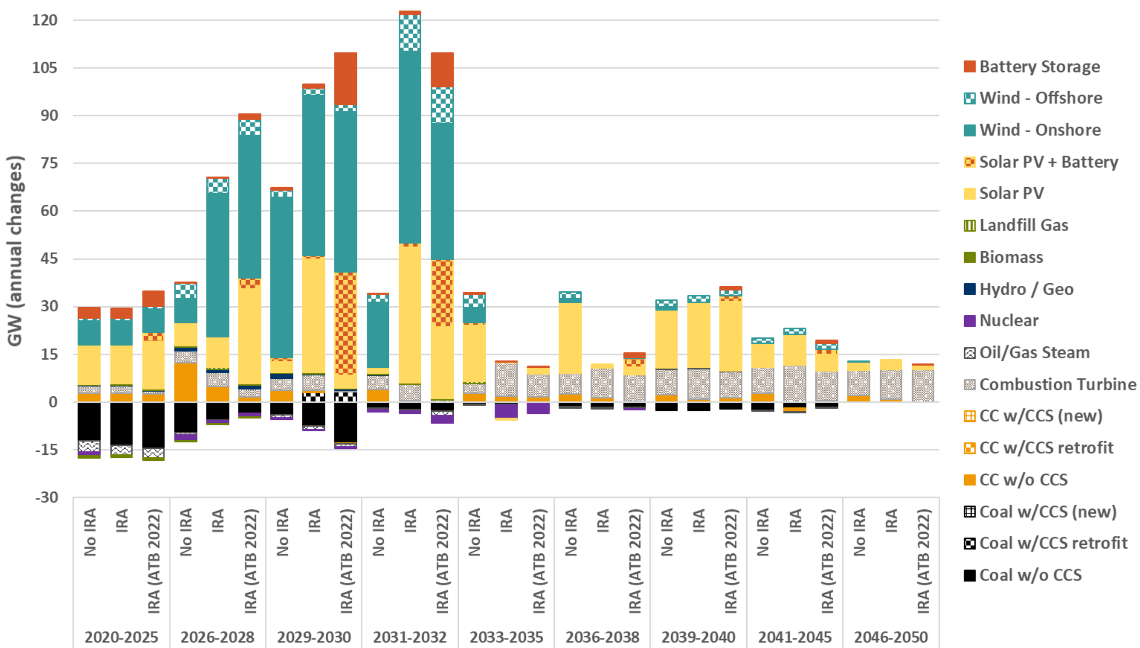
In the years after 2030, installation of renewables decline without the IRA credits as the best and cheapest sites have been used up. With the IRA, renewables installations continue through 2032 at a higher pace, particularly for onshore and offshore wind. If battery costs are higher, turbines tend to be installed for reliability, but if storage costs were lower (as was the case in the ATB 2022) battery adoption would remain high while the subsidies are available. After 2032, the most significant difference between the without and with IRA runs is the need for additional combustion turbines for reliability with the IRA-facilitated renewables. In the ATB 2022 scenario, which saw high levels of battery adoption, additional storage is potentially limited in the model by the use of EPA's modeling assumption that—beyond certain levels of battery storage in each region—additional battery installations are no longer as useful for meeting peak electricity needs (see Figure 31).

DIEM estimates there will be 81 GW of coal remaining in 2032 without IRA and 84 GW with IRA, compared to 200 GW in 2022 (of the 84 GW, 6 GW are retrofitted with CCS under IRA). Coal consumption at these units declines from 8.8 quadrillion Btu in 2020 to 2–3 quadrillion Btu in 2032 and beyond.[31] Given the estimated declines in coal capacity for conventional units and only modest conversion rates to coal with CCS, it may be appropriate to consider the future of coal markets more broadly and whether utilities will feel confident investing in coal-plant retrofits or whether concerns might arise that coal markets could decline to a point of limited viability in the future.

30 Based on the standard set of fuel price assumptions, DIEM does not forecast the retrofitting of gas combined-cycle units with CCS, which was seen in some other analyses.

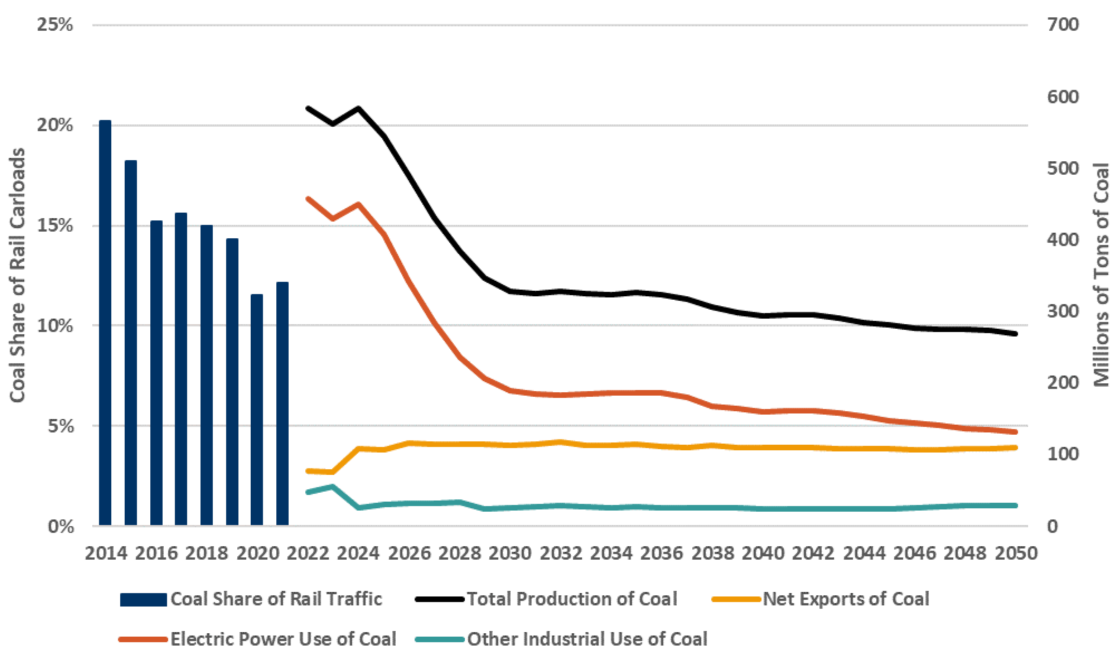
31 EIA's AEO 2023 has coal consumption of 2.5–3.5 quadrillion Btu in the years after 2032.

Figure 20. US annual capacity change: No IRA versus With IRA



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 2030 are shown as installations occurring in the 2029–2030 time period in the model.

Figure 21. Historical trends in coal shipments and AEO forecasts for future demands



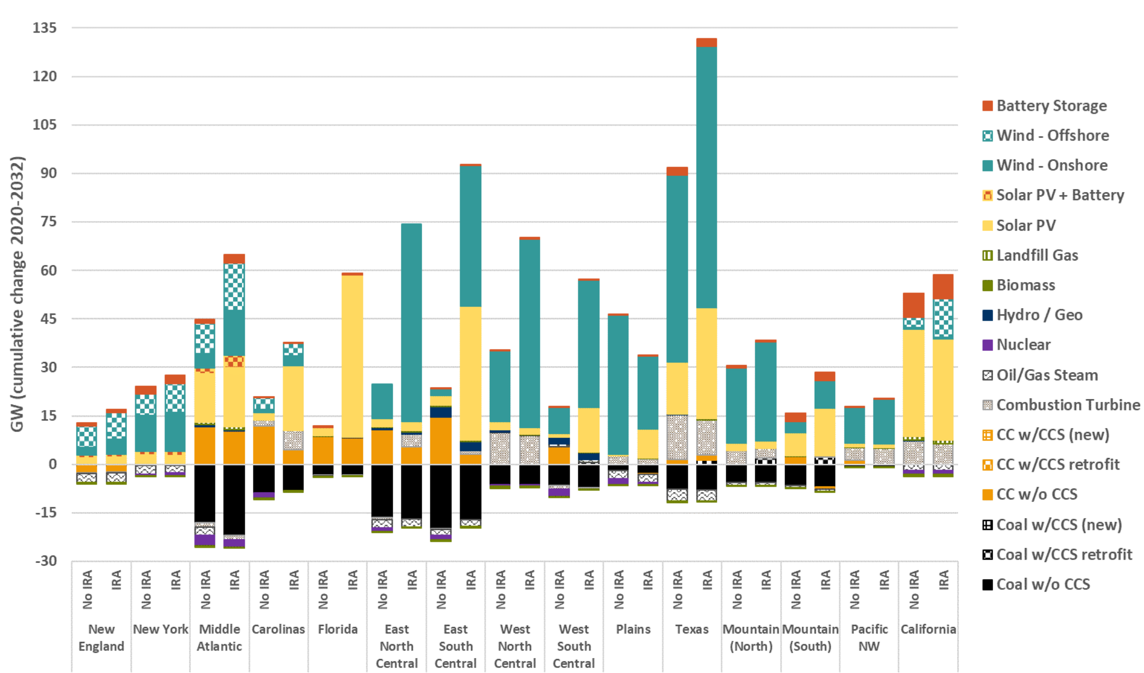
Sources: Association of American Railroads (AAR 2023), AEO 2023 Reference Case forecast (EIA 2023a)

As shown in Figure 21, coal shipments as a share of total rail carloads (on the left-hand side of the graph) have already declined by around 40% over the last decade. And, according to the AEO 2023 Reference Case economy-wide forecasts for the next several decades, outside of electric power, the largest source of demand for US coal is expected to be in export markets. If these foreign markets do not materialize because of factors such as climate policies outside of the United States, and if the AEO forecast of continued demand for coal in generation does not occur (as is the case in the DIEM policy results in Figure 27), the remaining sources of coal demand—which represent a small fraction of today's markets—may have difficulty supporting a viable long-term coal-mining industry. This could make it potentially risky to invest in coal CCS retrofits (although other industries such as cement or iron and steel may have fewer alternatives beyond CCS than exist in electricity generation.

How the 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. Tax credits in IRA can potentially either alter or accentuate these regional differences. Figure 22 compares No IRA and IRA forecasts over the next decade across 15 regions of the country (see Figure 15 for regional definitions). These results for the IRA scenario, and in most subsequent forecasts, use the standard assumptions based on costs from the current ATB 2023, unless otherwise noted. Highlights of regional implications include the following:

- The economics of renewables and other generation can change dramatically in some regions as the result of the IRA, while other regions might adopt similar strategies

Figure 22. Cumulative regional capacity changes through 2032: No IRA versus IRA demands



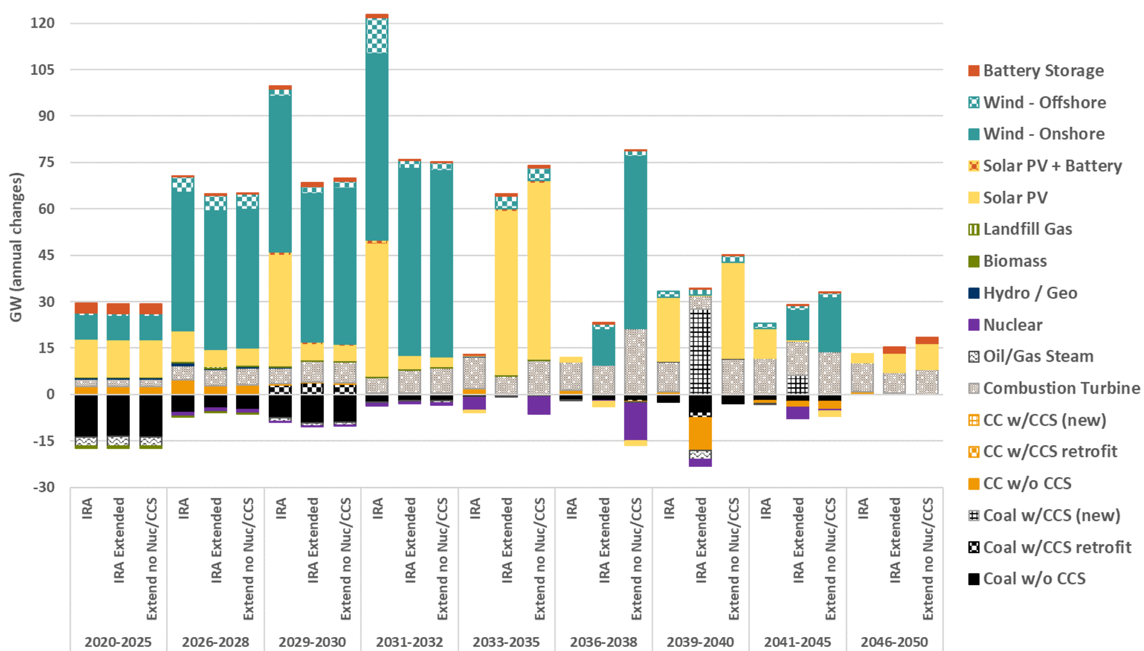
Source: DIEM model

regardless of IRA.

- Areas with preexisting climate regulations, such as the Northeast and California, pursue similar strategies with or without the IRA. Other areas—for example, states in the center of the country with available wind and solar resources—are able to more effectively expand their renewable generation as the result of the IRA tax credits.

Policy implications on the coasts—New England, Florida and California, and to a lesser extent, New York and the Pacific Northwest—are fairly comparable across the two policy alternatives. Other regions see a wider range of impacts. There are fewer nuclear retirements across the board for IRA, but capacity is more likely to remain in operation in the Carolinas and Central regions. The Middle Atlantic states add more solar and onshore wind under IRA and few combined-cycle units, while the Carolinas shift the expected mix somewhat under IRA and also expand their turbine fleet more quickly to enhance future reliability in the system. The four Central regions see some of the largest increases in renewables, especially for wind resources. Texas also expands wind generation, but was already on a path toward increased wind and sees a larger relative increase in solar from IRA. Many of the CCS retrofits on coal plants occur in Texas and several mountain states, with some in Louisiana (in the West South Central region), to take advantage of negative cost opportunities for CO_2 storage in EOR.[32] The Mountain regions see significant changes under IRA in relative terms but are a smaller part of the absolute changes across the nation.

Figure 23. US annual capacity change: Alternative IRA implementations



Source: DIEM model

[32] EOR storage receives $60/ton credit, rather than $85/ton, but is still the most cost-effective option available in the data.

In the past, tax credits for renewable generation have often been extended as they approach their expiration date. If the prevailing assumption among investors and utilities is that this could happen again with the IRA credits, it could reduce the pressure to quickly install renewables, potentially alleviating supply chain concerns and easing the grid's transition to low-carbon generation (though resulting in additional emissions in the near-term). In Figure 23, the three bars for each time period compare the original IRA results for the legislation as currently written (Figure 19) with two alternative extensions: in the IRA Extended case, all generation-related credits are extended through an installation year of 2050, including those for nuclear generation and carbon capture; in the Extend no Nuc/CCS case, the renewables credits are extended, but the $15/MWh production tax credit for nuclear and the CCS credits are not.

Highlights from this comparison include the following:

- Onshore wind capacity is relatively unaffected through 2032. Solar PV installations are shifted toward 2035.
- After 2032, the types of new units preferred depends on how the extension is formulated. Including nuclear and CCS in the extension leads to fewer nuclear retirements and eventually construction of new coal plants with CCS (in addition to retrofitting existing units in the early years) as anticipated construction costs decline toward 2040.
- Extending only the renewables portion of IRA causes a significant shift out of nuclear generation and into renewables in the 2033–2038 time frame.

In the early years through 2028, an extension of the IRA program (assumed to be announced by 2025 for the model's planning purposes) forestalls some of the rush to install renewables immediately, especially for solar PV—wind still is added quickly. After 2032, the evolution of the industry would depend more on which types of credits are extended, though solar construction is high under either option. Extending the nuclear production credits after 2032 prevents the retirements of nuclear seen in 2032 under the current IRA approach. This extension also reduces the need to expand new gas turbines as much as if the nuclear credits end in 2032. After 2035, the biggest differences are in the construction of new coal plants with CCS in 2040, if they receive credits under the extended IRA (shown as 2036–2040 here). By 2040, the cost of new coal with CCS in the AEO 2023 forecasts used in DIEM has declined from around $6,500/kW in the near term to $4,700/kW, making new CCS installations more economic. These new units take the place of some renewables and gas turbines in the longer term.

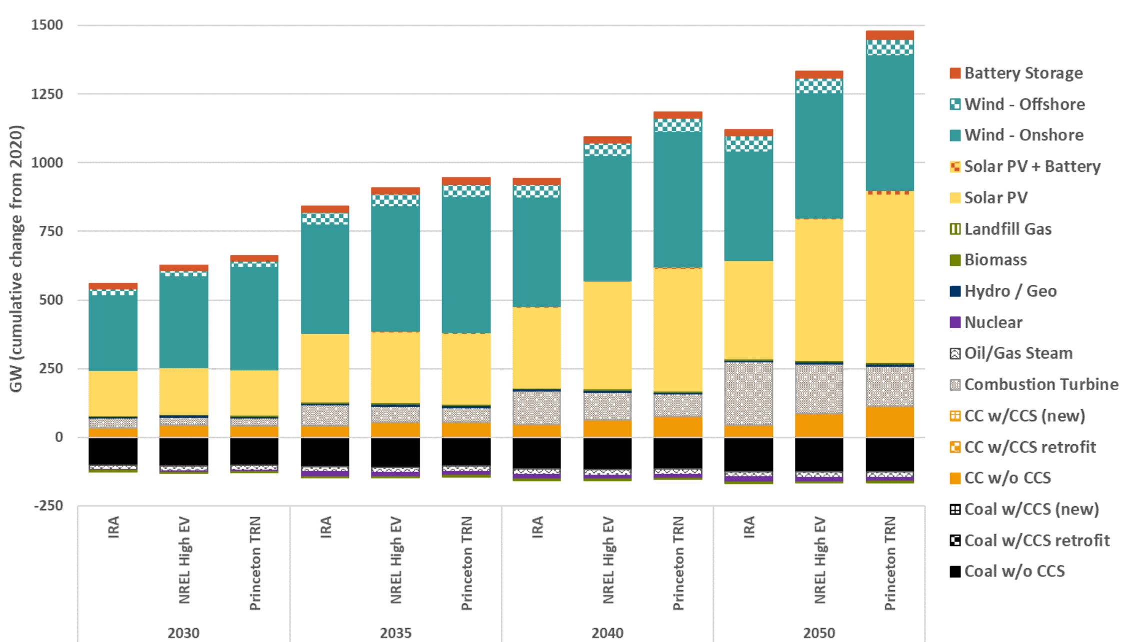
Although the AEO forecasts don't suggest major changes in electricity demand as the result of IRA, other forecasts focusing on overall electrification have projected potentially significant increases in electricity demand—particularly when compared to the AEO where demand typically grows at less than 1% per year (see Figure 13 above). How this electricity is generated will be a factor in determining the net emissions benefits of electrification. The focus here is on the sources of generation for the transportation sector using two alternative forecasts: NREL High EV is the personal electric-vehicle component of high-adoption forecasts from the Electrification Futures Study (NREL 2018), and Princeton TRN includes all transportation-sector electricity demand from their Net-Zero report (Jenkins et al.

2021)—but not demands from other sectors of the economy so that it can be compared more readily to the NREL case. Highlights of the findings (shown as cumulative additions through future decades) include:

- An expansion of solar generation helps provide much of the additional electricity needed by electric vehicles. Wind expands, but the most cost-effective locations are already being utilized under IRA without an extra demand from EVs.
- Expansion of natural-gas capacity shifts from combustion turbines (for reliability purposes) into combined-cycle units that can also provide baseload generation as demand increases.

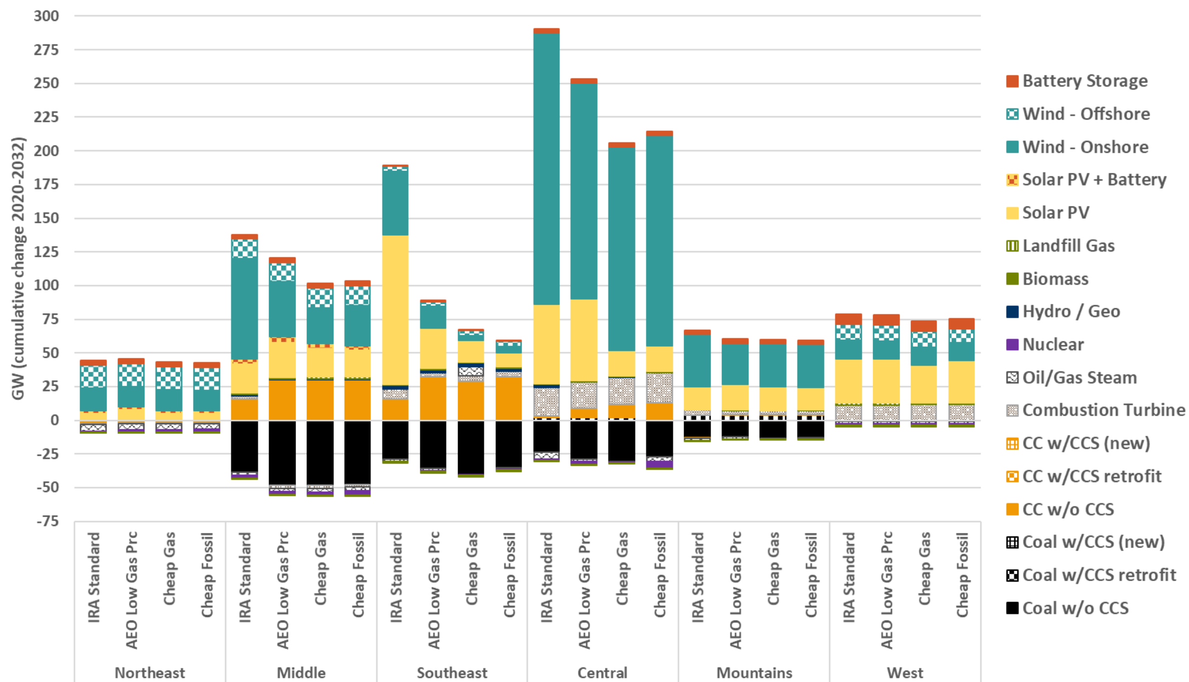
Starting from the main IRA scenario, demands from vehicle electrification take hold slowly in the near term, as shown by the extra cumulative new capacity represented the heights of the columns in Figure 24. Approaching 2040 and on through 2050, there are more substantial requirements of additional capacity to supply vehicles. Somewhat fewer nuclear retirements are seen—declining from 18 GW of retirements to potentially 13 GW—along with minor changes in the coal fleet. Wind generation adds an extra 50–100 GW of capacity depending on electrification needs, but the more significant action is in solar and gas combined-

Figure 24. US cumulative capacity change from 2020: Varying transportation demands



Source: DIEM model

Figure 25. Cumulative regional capacity changes through 2032: Alternative fuel prices



Source: DIEM model

cycle capacity. Combined cycle adds up to 70 GW and solar PV capacity is up to 250 GW higher than the main IRA scenario with electricity demand growth of only 0.7% per year.

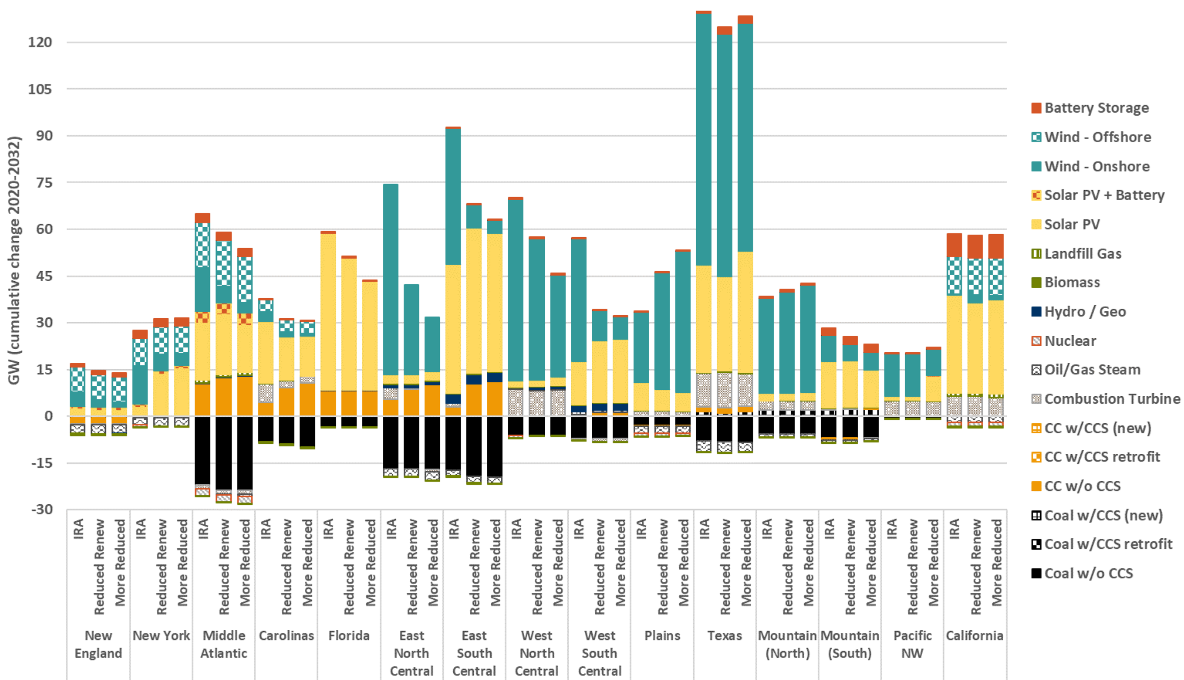
Sensitivity of IRA Capacity to Assumptions

Figure 25 examines how broad regional capacity additions may respond to alternative natural-gas price trends. Highlights of these cumulative trends between 2020 and 2032 include the following:

- Gas prices have large impacts in some parts of the country and limited impacts in others.
- Capacity on the coasts is relatively insensitive to gas and coal prices.
- Much of the wind in the center of the nation remains economically viable, regardless of prices.
- The Middle Atlantic, eastern Midwest, and Southeast are much more likely to shift out of renewables and into gas generation if fuel prices are lower.

Overall, cheap gas will tend to crowd out renewables (and some nuclear). However, these effects are not evenly distributed around the country, nor are the types of renewables affected. In the Middle region, wind faces the most direct competition with gas while solar is relatively unaffected. In the Southeast, solar declines substantially in the face of cheap gas, but wind is also impacted. The center of the country, which includes the low-cost wind

Figure 26. Cumulative regional capacity changes through 2032: Renewable resources



Source: DIEM model

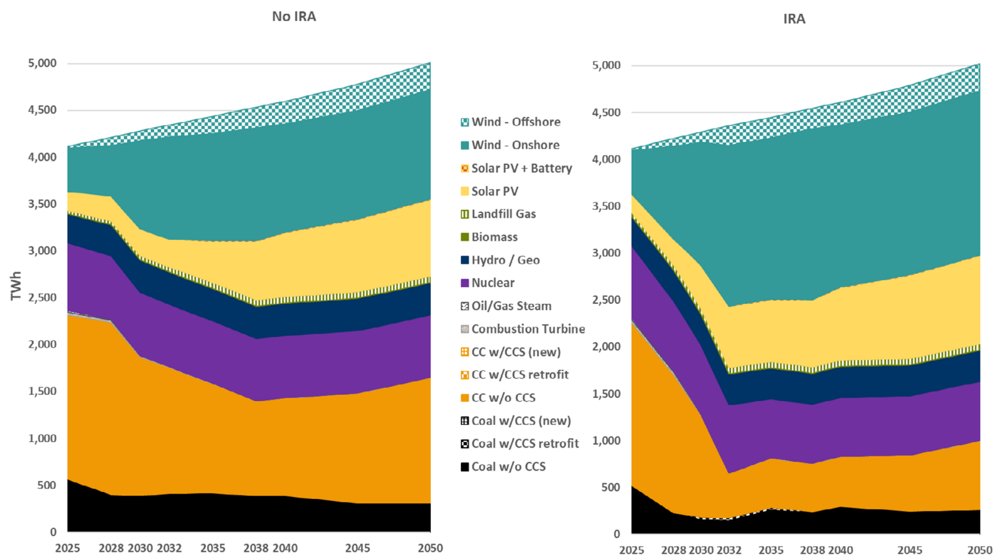
resources across the Plains states and Texas, reduces solar capacity in response to low-priced gas, but the wind resources in these states remain fairly cost-competitive. In other regions of the nation, capacity changes as the result of cheap gas are limited—though electricity prices and generation from existing gas units may be affected to a larger degree.

Figure 26 illustrates potential changes in capacity between 2020 and 2032 under the IRA, depending on the availability of renewable resources at a more detailed 15-region level (many of the largest differences are seen in specific states where limitations on the siting of renewables have the biggest impacts). Highlights of the sensitivities include the following:

- Demand for renewable generation remains under the IRA, regardless of potential limits on its development.
- Regional differences can be significant, but some of the variation is the result of shifting renewables from one area (e.g., the North Central states) to another (e.g., the Plains states).
- Given the abundance of solar resources and potential sites around the country, the biggest differences are seen in onshore wind capacity.

Restrictions on the use of renewable resources such as limits on siting options lead to higher national emissions, as shown in Figure 18. The most important driver in these differences comes from shifting from renewable to gas generation. Although Figure 26 obscures more dramatic differences across the renewable sensitivities that can be seen at the state level,

Figure 27. US generation: No IRA versus With IRA



Source: DIEM model

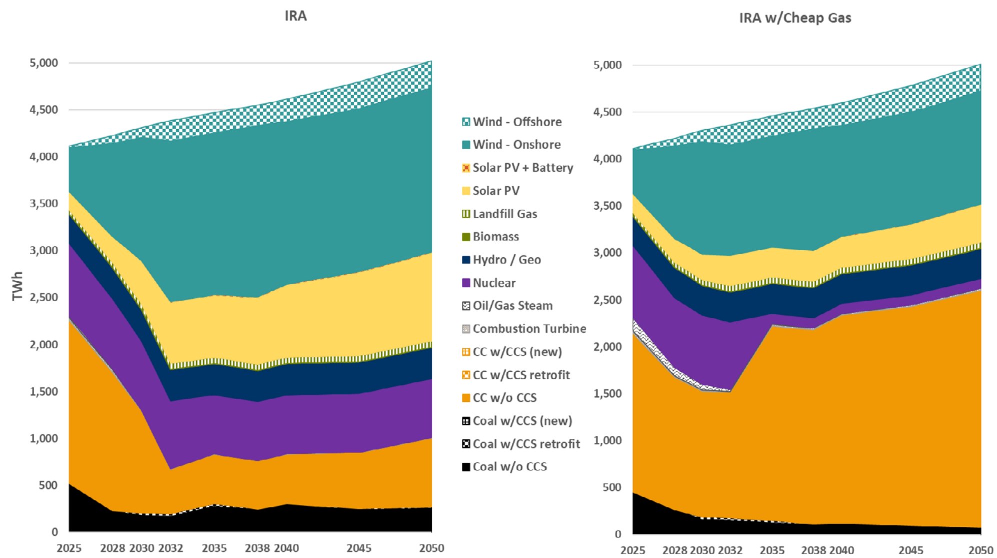
the findings show how limitations on adoption of renewables—broadly applied—may have different effects across states and regions. Some states may even be positioned to expand their renewable generation because of their availability of cost-effective options, if other states are limiting adoption.

Generation Patterns Under IRA

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 27 contrasts trends without and with the IRA at a national level through 2050. Highlights of the findings include the following:

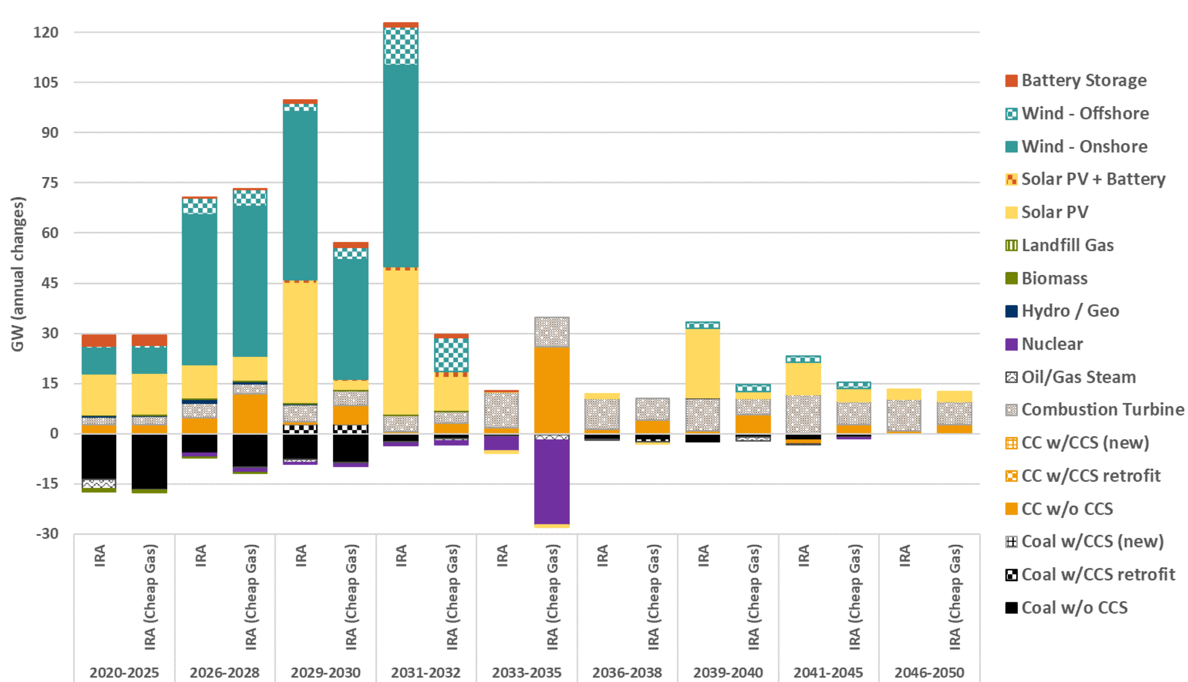
- Without the IRA, coal generation remains fairly constant, although at lower levels than today. With the IRA, coal generation dips through 2032 but remains an important contributor through 2050 (coal capacity is around 56 GW in 2050 without the IRA, compared with 62 GW with the IRA, of which 5 GW remain from those initially retrofitted with CCS. However, the CCS component of these units is unlikely to be active without continuing subsidies provided for capture and storage).
- Gas generation is displaced by renewables both with and without the IRA credits, based on the standard DIEM assumptions about gas prices.
- Renewables expand significantly over the next decade, with onshore wind seeing the largest increase as the result of IRA.
- Nuclear generation continues even after the IRA expires, assuming that gas prices remain around $3.5/MMBtu as in the set of standard DIEM assumptions.

Figure 28. US generation: IRA with Standard Assumptions versus IRA with Cheap Gas



Source: DIEM model

Figure 29. US annual capacity change: IRA with Standard Assumptions versus Cheap Gas



Source: DIEM model

Figure 28 compares the IRA findings under the standard assumptions regarding gas prices based on AEO trends to an IRA scenario that uses delivered gas prices from the EPA IPM model (which are around $2/MMBtu). Highlights of these alternatives include the following:

- Cheap gas can displace a large share of potential renewable generation, even with IRA credits, leaving renewables similar to—or lower than—what was seen without the IRA (assuming more expensive gas).
- Cheap gas can also displace most nuclear generation once IRA production credits for nuclear are phased out.

Figure 29 presents the capacity changes that underlie findings in the graph of generation without versus with the assumption of cheap gas supplies. Through 2028, cheap gas has limited effects on renewable installations, but results in a rapid expansion of gas combined-cycle units. After 2028, low-price gas first crowds out solar that would have appeared by 2030 and then onshore wind that would have appeared by 2032. Once the IRA credits for nuclear generation expire, the economic incentives associated with cheap gas lead to significant retirements of nuclear units, which are replaced by new combined-cycle units (assuming that utilities have planned ahead of time for this transition).

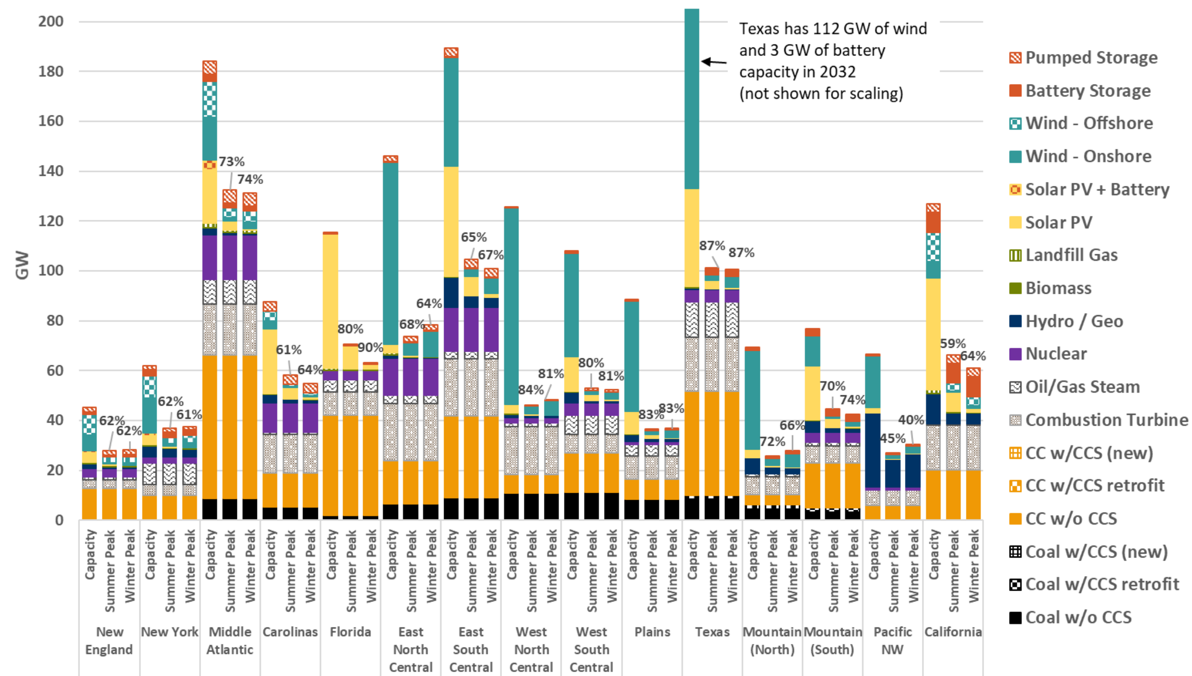
Provision of Reliability Services Under the IRA

How reliability services are provided becomes increasingly important as renewables form a larger share of total generation. Historically, these services have been provided by fossil generators across the spectrum of baseload, intermediate, and quick-start units. As the grid transitions, more types of reliability services will need to be provided through other means such as storage. The basic ability of the system to meet peak or unanticipated demands depends on having dispatchable generation and/or storage available for sudden needs. These needs, and the ability of renewables to contribute depends on—among other things—the season of the year and the time of day during which any peaks occur. Along with its more detailed representation of operating reserves and incorporation of hourly considerations, the DIEM model distinguishes between reserve margins for the summer and winter peaks as they tend to occur in different hours, during which wind and solar resources may have dissimilar generation profiles.

Figure 30 shows total capacity by region in 2032 for the main IRA scenario, along with how that capacity is credited toward meeting summer and winter reserve margin requirements related to peak demands. The difference between the total capacity shown and how that capacity is credited toward meeting peaks illustrate the relative value of different types of generation for overall system reliability. In the figure, the numbers shown on top of the seasonal peaks indicate how much of the peak is being met by fossil generation. Highlights of these findings include the following:

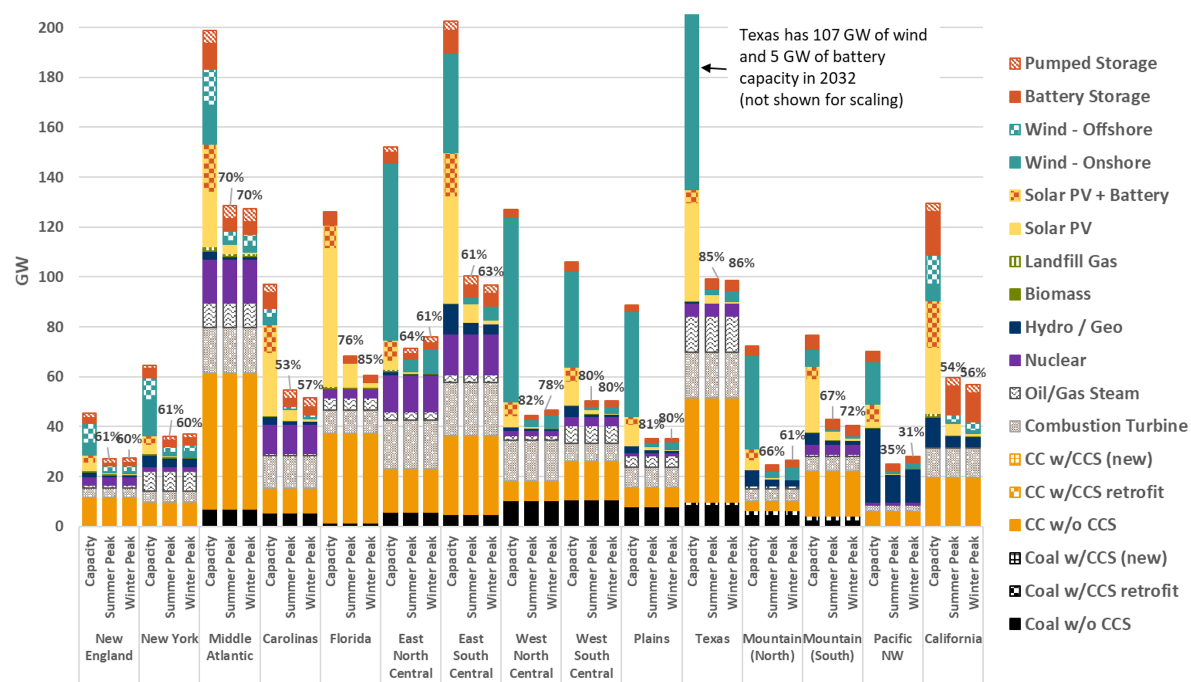
- DIEM (and other models) tend to keep nongenerating fossil units in the system for significant periods of time to meet reserve margins. On average in 2032, more than 71% of the capacity used to meet reserve margins is from fossil units (not including nuclear).
    - How realistic is this approach to operations and how may such choices be influenced by uncertainty over any future climate policies?

Figure 30. IRA capacity contributions to meeting peak reserves in 2032



Source: DIEM model

Figure 31. IRA (ATB 2022) capacity contributions to meeting peak reserves in 2032



Source: DIEM model

- Given the higher battery costs estimates in the ATB 2023 forecasts, only 2.3% of peaks are met through battery storage, on average.
- Regions with the highest levels of wind and solar such as the Plains states and Texas tend to maintain the highest shares of fossil units for reliability.

Figure 31 provides similar information for the IRA scenario based on the lower estimates of renewables and storage costs in the previous ATB 2022. The biggest difference in meeting peak demands in this system configuration, aside from higher overall wind and solar capacity, is the greater share of battery storage. With less expensive batteries, storage capacity increases from around 22 GW in 2032 (Figure 30) to 84 GW in this scenario, which contributes more than 5.5% of the needs for meeting reserves. However, as more batteries are added to a system, they can become less effective at contributing to peak needs. Based on the EPA IPM data used in DIEM, only 58% of the availability battery capacity of 84 GW is contributing to peak reserves, reducing the value of these batteries aside from their ability to spread out generation from renewables (which is unaffected by these reserve margin assumptions). In contrast, with only 22 GW of batteries in the main IRA scenario, 93% of the batteries are credited toward meeting reserves.

Transmission Under the IRA

Transmission is one of the areas with the largest divergence across modeling systems and analyses, both in the costs for new lines and in the overall representation of the system. Unlike possible modeling techniques for representing additional levels of detail for existing capacity or for the sites and supply curves for new renewables, there are no potential mechanisms to alter how the size and regional representation in an electricity model determines how the transmission system is defined. Typically, within an individual region in a model, it is assumed that electricity flows freely (i.e., no new lines are needed for intraregional transmission). Across regions, models choose a node for each region—whether a geographic or demand-related center—and build new lines between nodes.[33]

Thus, the size of regions directly controls the areas of freely flowing electricity and the distances (and costs) of new lines between regions. Models with aggregated regional representations have more free flows of electricity and presumably higher costs of adding new lines, if average distances between the aggregated regions are longer. Conversely, the tradeoff for models with more regional detail is that they are much slower to solve. The DIEM model attempts to balance these factors and has more detail than many models (e.g., Princeton REPEAT, Resources for the Future [RFF] Haiku, EIA NEMS, or Electric Power Research Institute [EPRI] US-REGEN), but somewhat less than others such as the EPA IPM or NREL ReEDS models (the ReEDS system has the most detail with 134 regions within the continental United States).

Aside from differences in regional structures, assumed costs of new transmission lines appear to vary significantly across modeling systems. The DIEM model uses data from the NREL ReEDS system, which distinguishes between AC and DC lines. AC lines cost around $3,300/MW-mile and DC lines are 40% of the AC cost, although they also require AC/DC

[33] Alternatively, a model could choose a line length between regions that only represented a short distance across the border between two regions, but would still have free flows of electricity within the region.

converters at $140,000 to $180,000/kW at each end of a DC line. AC line losses are 1% per 100 miles and DC lines are 0.5% per 100 miles (with these costs, all—or most all—of the new lines installed in DIEM are DC lines). DIEM also uses NREL data on fixed O&M costs related to maintenance of the grip, equivalent to 1.5% of grid capital expenditures value per year. Other models appear to have substantially different assumptions about line costs. For example, the EPA IPM model appears to use line costs—irrespective of AC or DC—of around

Table 3. Interstate transmission capacity (GW)

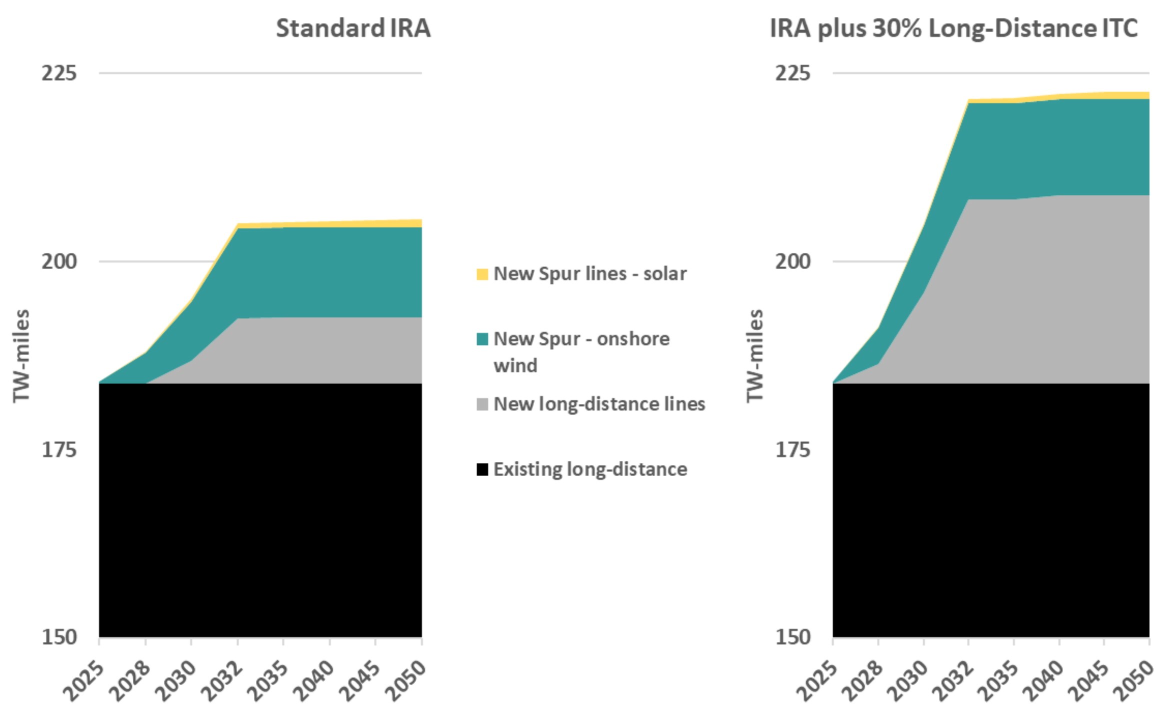
Origin Region	Destination Region	Standard IRA			IRA plus 30% Transmission ITC		
		2028	2030	2032	2028	2030	2032
Middle Atlantic	East South Central	—	—	—	—	—	10.1
	West North Central	—	—	—	—	—	0.9
East North Central	East North Central	—	—	10.0	—	—	—
	West North Central	—	5.4	0.3	1.5	16.0	0.8
East South Central	West South Central	—	—	0.9	0.1	3.6	3.1
West South Central	East South Central	—	—	—	—	—	0.1
Plains	Mountain (South)	—	—	2.2	—	—	3.1
	Mountain (North)	—	—	—	—	—	0.7
Mountain (North)	Mountain (South)	0.1	0.8	0.4	1.4	0.3	0.1
	Mountain (North)	—	—	—	—	0.3	—
Mountain (South)	Texas	—	—	—	—	—	—
	Mountain (North)	—	0.1	0.2	0.6	0.3	1.1
Texas	Mountain (South)	—	—	0.3	0.5	—	1.2
	West South Central	—	—	—	0.9	—	—
USA	**USA**	**0.1**	**6.3**	**14.3**	**5.1**	**20.5**	**21.2**

$1,800/MW-mile (based on this author's calculations). The model also defines line losses as a fixed percentage between regions (equal to 2.4% to 2.8%). The Princeton REPEAT model uses long-distance line costs that average around $1,300/MW-mile (2013$) in most regions of the country, and up to around $3,000 to $3,500/MW-mile in more congested areas such as California or the Northeast.

In the IRA scenario, the DIEM model shows investments in new long-distance transmission capacity in gigawatts, aggregated from the state-level data in the model to the 15-region summary metric used in other figures (Table 3). In addition to the results from the main IRA scenario, the findings also show how much additional capacity might have been installed if a 30% investment tax credit for new transmission lines had remained in the legislation. Highlights of the findings include the following:

- Long-distance transmission is expensive and potentially hard to permit and site (although this factor is not considered in the model, aside from associated costs). Some new capacity is expected between states and regions of the country, but relatively limited amounts.
- An investment tax credit for transmission would likely have provided a significant incentive for additional new capacity.
- Areas most likely to install new capacity are those in the central part of the nation that experience the largest expansion in renewables, and the mountain regions—both

Figure 32. Transmission line length (TW-miles)



Source: DIEM model

among the mountain states and across the Eastern-Western Interconnection interface.

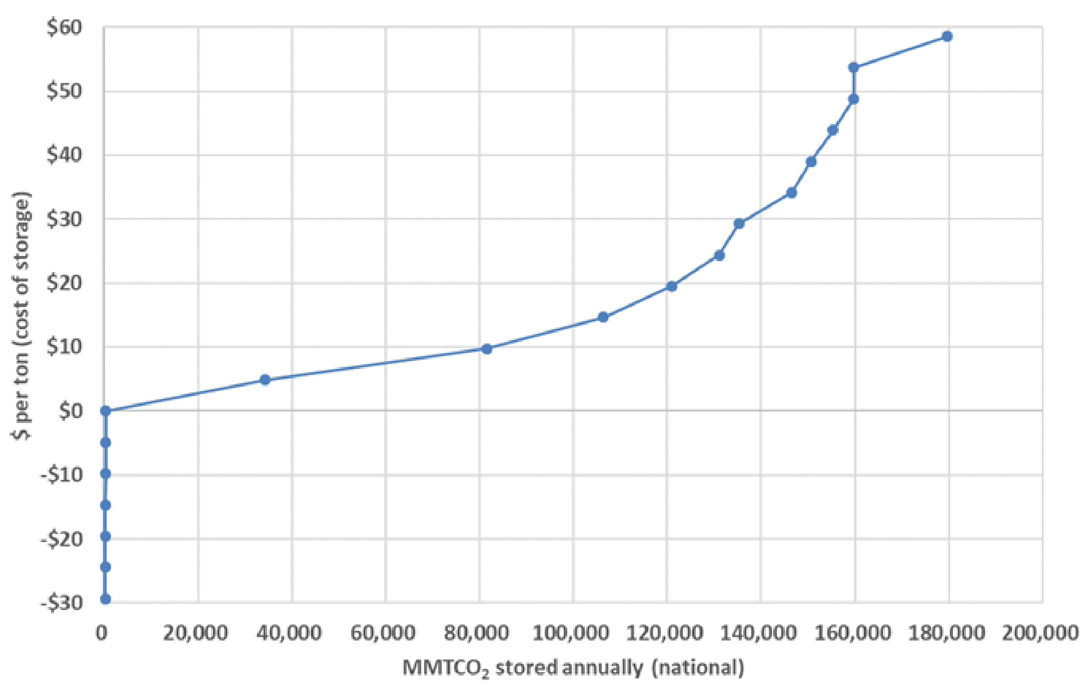
Figure 32 provides a sense of the scale of the increase in total transmission-line length implied by both the additional interstate capacity shown in Table 3 and an estimate of the length of the new spur lines need to connect the onshore wind and solar capacity additions implied by the IRA scenarios. For the standard IRA case, by 2032 there is a 12% increase in the total lines needed, compared to a 21% increase for the case where a 30% investment tax credit is added to the existing IRA credits.

Carbon Capture Under the IRA

The IRA includes significant incentives for capturing and using or storing CO_2. The analysis assumes that CCS retrofits and new units become—potentially—widely commercially available for generation by the beginning of 2030. This implies that new units would have begun construction by the beginning of 2026 with a four-year lead time. Use of the timing same assumption for retrofits of existing coal and gas units is based on the approach of the EPA IPM model (see Chapter 6.1.2 in EPA 2023c). The IRA provides for credits of $60/ton of CO_2 stored if used for EOR or $85/ton if sequestered—assuming that bonuses for meeting labor conditions are achieved—and runs for 12 years of operation.

For the retrofit of existing coal plants, capital costs range between $1,900 and $2,600/kW, depending on the heat rates of the units in question. There are also capacity penalties of 28% to 34% as CO_2 capture requires a portion of the unit's electricity to operate, implying heat

Figure 33. EPA national CO_2 storage costs and availability



Source: Author's calculations based on EPA 2023c.

rate penalties of 38% to 50%. Although new CCS units are not selected in most model runs (unless IRA credits are extended), capital costs are around $2,000 to $2,800/kW higher than for conventional gas and coal units (AEO 2023).

Once the CO_2 has been captured, it must be transported and stored. Costs and anticipated annual and cumulative storage volumes are based on the EPA IPM model (EPA 2023c) and are summarized in Figure 33. Negative storage costs are associated with the potential benefits of using CO_2 in EOR and include up to 315 $MMTCO_2$ of storage available annually at prices below zero. However, this analysis does not consider any new emissions associated with the additional oil that is produced using EOR (see ETC [2022] for a discussion of the possible range of net emissions benefits of using CO_2 storage in EOR).

For the main IRA case, DIEM estimates that around 6 GW of coal units will be retrofitted with CCS in 2030, which then capture around 26 $MMTCO_2$ annually (Table 4). No new coal or gas units with CCS are constructed in this scenario, nor any retrofits of existing gas units. As seen in the results, the coal plants are generally located near where negative storage costs from EOR are available, and the transport costs to reach those locations are modest in comparison to the storage costs and the IRA credits for CCS.

Costs Under the IRA

Policy costs and benefits associated with the IRA can be expressed in a number of ways. Presenting these costs in more than one way can overcome challenges inherent in any individual approach (note that none of these metrics incorporate any benefits from avoided pollution damages). On one hand, the most direct impacts on household and other consumers of electricity are the changes in retail electricity prices and bills. From another perspective—that of utilities and other generators—the entire system's expenditures

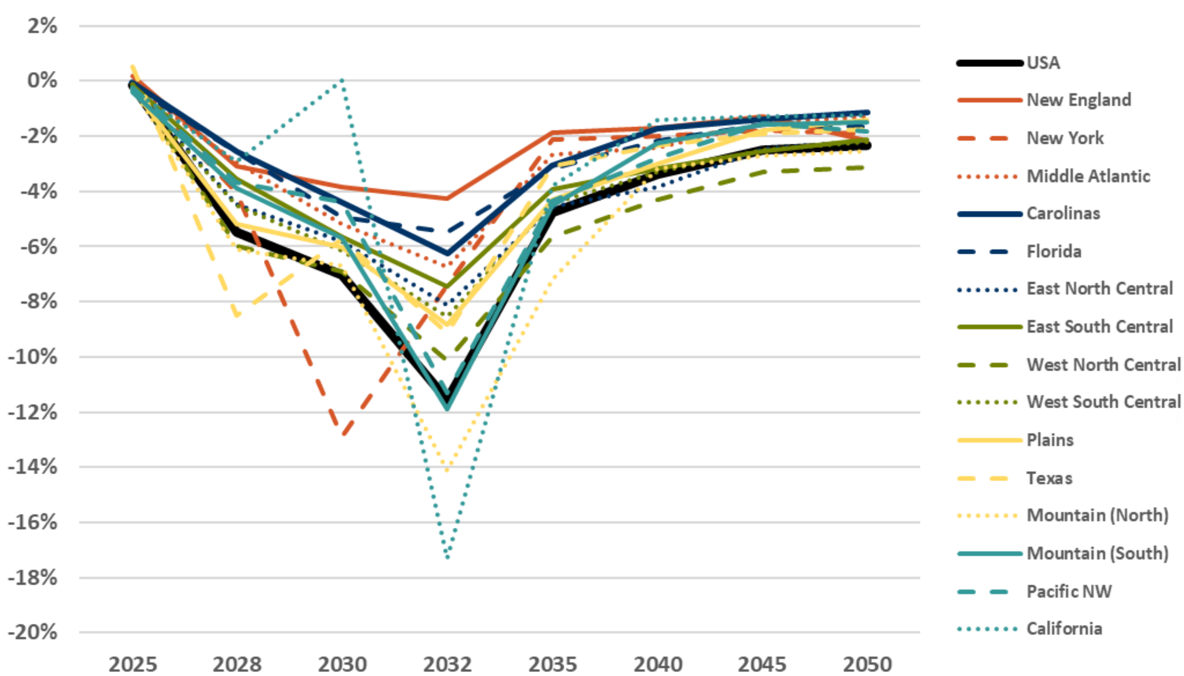
Table 4. IRA carbon transport and storage quantities and average costs selected by DIEM (in 2032)

Origin State	Destination Location	Quantity ($MMTCO_2$ annually)	Transport Cost, $/ton	Storage Cost $/ton	Total Cost $/ton
Colorado	Colorado	1.6	$12.6	-$29.3	-$16.7
	Kansas	3.1	$26.8	-$29.3	-$2.5
	New Mexico	0.5	$30.8	-$29.3	$1.6
Louisiana	Louisiana Onshore	2.6	$13.4	-$29.3	-$15.9
New Mexico	New Mexico	6.5	$15.5	-$29.3	-$13.8
Texas	Texas Onshore	6.2	$22.9	-$29.3	-$6.4
Utah	Utah	2.5	$10.8	-$24.5	-$13.6
Wyoming	Wyoming	3.2	$11.4	-$29.3	-$17.9
USA	USA	26.2	$17.6	-$28.8	-$11.3

associated with delivering electricity may be the most relevant measure. The standard calculation from this viewpoint is to compare the change in net present value (PV) between a policy run and an associated baseline run (or reference case) in a model. This logic roughly corresponds with the way capacity-planning models attempt to minimize total costs of generating electricity, and the present value calculation provides a simple metric that can be compared across scenarios. Finally, for administrators of the IRA program, it will be important to understand potential outlays associated with the IRA tax credits. Across any of the options, it is more difficult to accurate assess the costs and benefits of IRA than has been the case in most types of past policy analyses for two reasons: (1) the costs of the tax credits are borne outside of the electricity system, and (2) the price of natural gas is significantly lower in the IRA scenarios than in the No IRA scenarios (this complicates direct cost comparisons across the two scenarios, compared with the standard practice of using the same set of fuel prices—or at least the same fuel-price supply curve—across scenarios). Consequently, any cost results for IRA should be interpreted with caution.

Figure 34 shows relative changes in retail electricity prices between the IRA and No IRA cases in DIEM for a 15-region aggregation of the state-level results, along with US average impacts.[34] As seen in other analyses, subsidizing specific types of generation such as

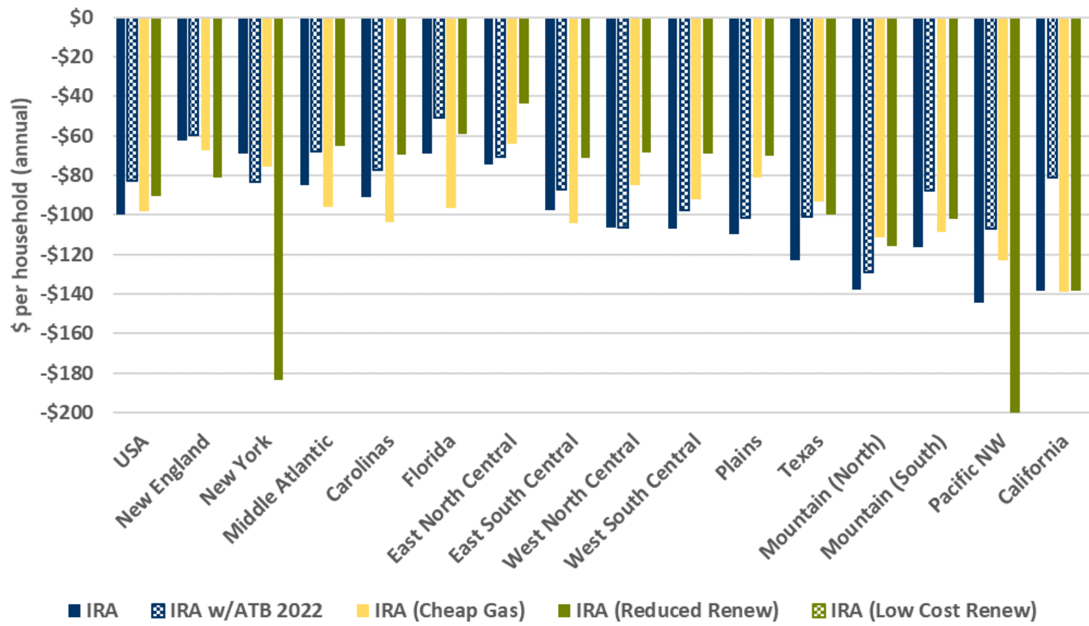
Figure 34. Changes in regional electricity prices resulting from the IRA



Source: DIEM model

[34] Retail prices are calculated using logic from the NREL ReEDS model (NREL 2020) that looks at relative changes in wholesale costs and initial retail prices for different classes of consumers (residential households, commercial businesses, industry, and transportation).

Figure 35. Changes in household bills resulting from the IRA (2032)



Source: DIEM model

renewables can lower the marginal costs of generation, to the extent that electricity from new renewables is the price-setter in the markets during at least some seasons of the year and times of day. Lower gas prices in the IRA scenarios also lower costs for gas units that can be the price-setter on the margins.

The declines in estimated prices tend to peak during final year of the IRA implementation as it represents the point with the most new capacity and generation receiving the tax-credit subsidies. Impacts can vary by region and year depending on the timing of the new renewables generation, but most follow a similar pattern with declines in prices ranging from 6% to more than 12% in 2032 and averaging around 11%.

These changes are also expressed as the corresponding dollar change in residential household bills. Converting these price declines into a measure of household spending gives an average decline of up to $100 per household per year by 2032, the highest impact year. At a regional level, these declines range from $66 per household in the Northeast to $140 in the West in 2032 with, however, more variation in 2030 prior to the final year of the IRA.

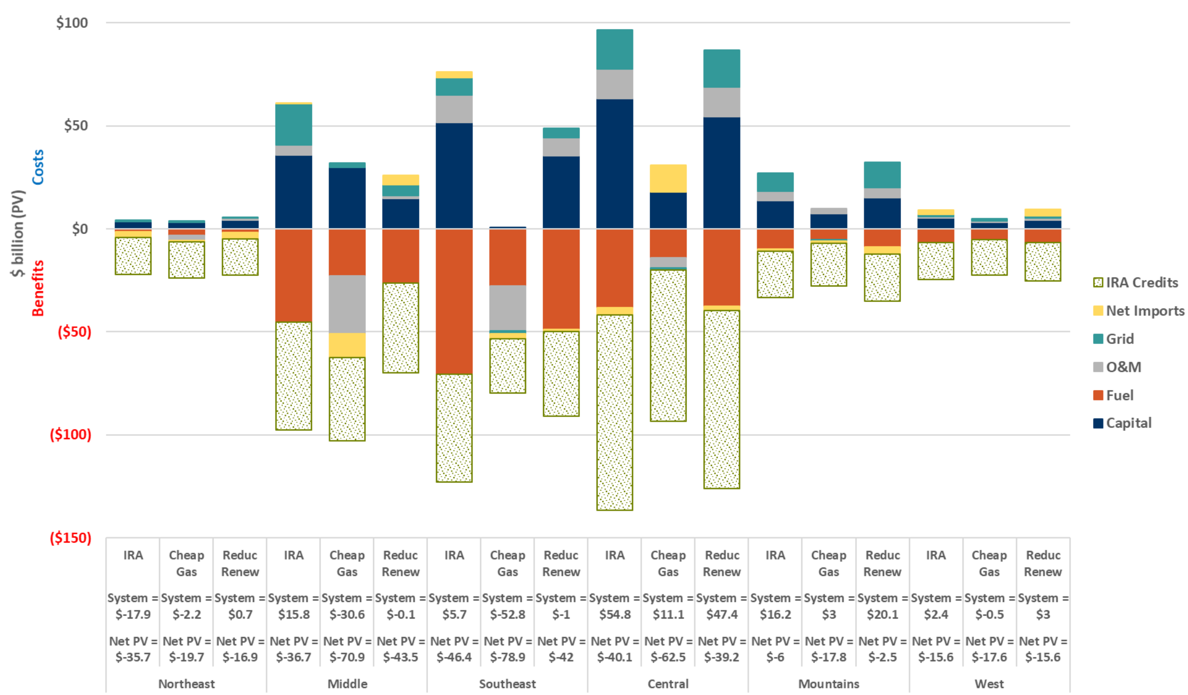
Costs to the system as a whole cover those directly related to generating electricity: capital costs of new construction or retrofits (typically annualized for cost-reporting purposes);

[35] Other types of "costs," such as proceeds from RGGI allowance auctions or carbon pricing (although the modeled carbon adder policies do not require payments to be made), may affect generation decisions in the model. However, for cost-reporting purposes, are simply a transfer among agents in the economy and do not represent a net cost to society as a whole. Therefore, they are not reported here.

fixed O&M annual expenditures; variable O&M costs, which vary with the level of generation; costs of maintaining and expanding the grid; and fuel costs.[35] When evaluating these costs, it is important to bear in mind that electricity dispatch models minimize policy costs over the entire model time horizon. Estimating shorter-term policy costs can be problematic because, for reporting purposes, capital payments are annualized (usually over 20 or 30 years) from the date of installation, and over any shorter reporting horizon all the annualized capital payments may not have been fully realized. Thus, the system costs discussed below are net-present values through 2050.

Typically, measures of system costs do not include costs or benefits coming from subsidies and taxes, proceeds from Regional Greenhouse Gas Initiative (RGGI) allowance auctions, or carbon pricing. These costs may affect generation decisions in a model, but for cost-reporting purposes, they are simply a transfer among agents in the economy and do not represent a net cost to society as a whole. However, for the IRA there is a direct link between the level of tax credits received and the capital costs of installing new renewables. To show the relative scale of both the typical system costs and the IRA credits, Figure 36 distinguishes each set of values at a regional level. The labels below each scenario shown—IRA, IRA with Cheap Gas, or IRA with NREL's Reduced Renewables—illustrate the net system costs (system classified into capital costs, fuel, O&M, grid, and net imports) and then an overall net present value

Figure 36. System cost change in NPV through 2050 (compared to No IRA scenarios)



Source: DIEM model

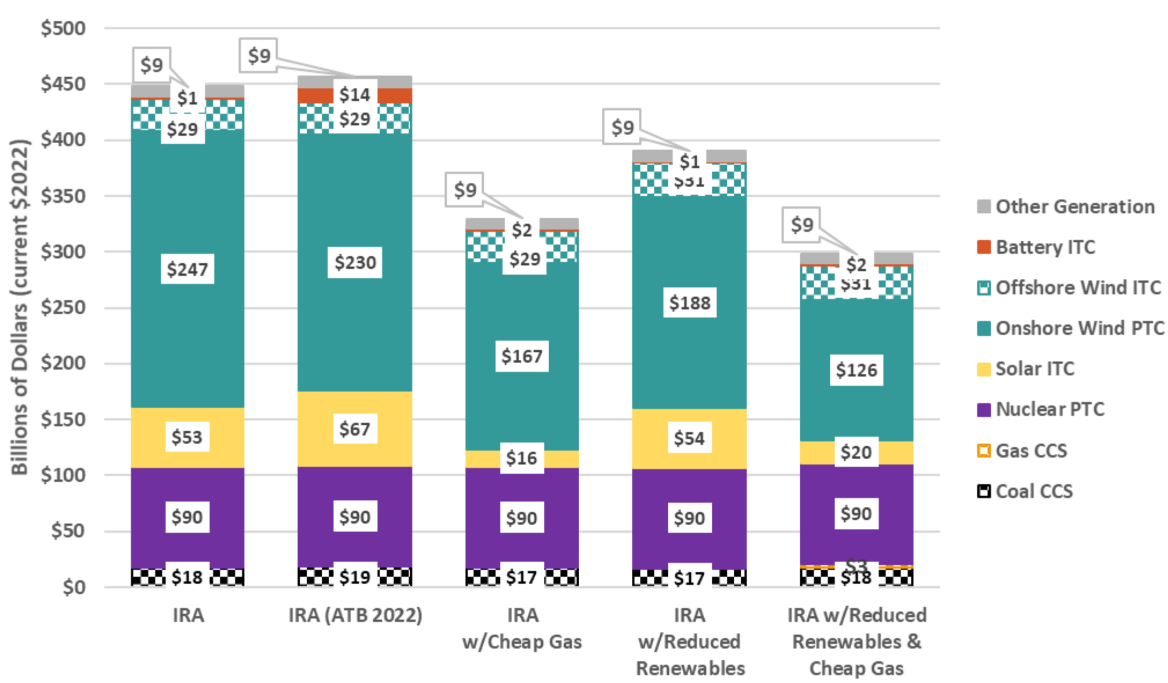
[36] For reporting capital expenditures in this graph, which separates out the IRA credits, the value of these credits are backed out of the capital payments used to calculate system costs.

(NPV) that also includes the value of the credits received to offset additional capital expenditures associated with IRA.[36] How these expenditures (the positive values or costs above the zero line) and values of the IRA credits (the negative values or benefits below the zero line) are distributed across the economy does not affect how the model finds the most cost-efficient solution.

Highlights of the estimated system costs and benefits include the following:

- Capital expenditures (higher for renewables and modestly lower for fossil generation) are concentrated in the middle of the country as opposed to the coasts.
- IRA tax credits are also concentrated in these regions, although the coastal states receive a larger share of credits relative to the changes in capital costs (as a function of these states pursuing similar actions on renewables even prior to IRA).
- Fuel costs are down across all regions for two reasons: (1) IRA shifts generation into renewables and out of fossil fuels and (2) the assumed natural gas prices in the IRA scenarios are significantly lower than in the No IRA scenarios that are the point of comparison for the net costs shown in the graph.
- The Cheap Gas scenario shifts generation toward gas and away from nuclear. This results in significantly lower O&M expenditures overall as nuclear units have the highest O&M expenses.

Figure 37. Cumulative value of IRA credits by type (undiscounted)



Source: DIEM model

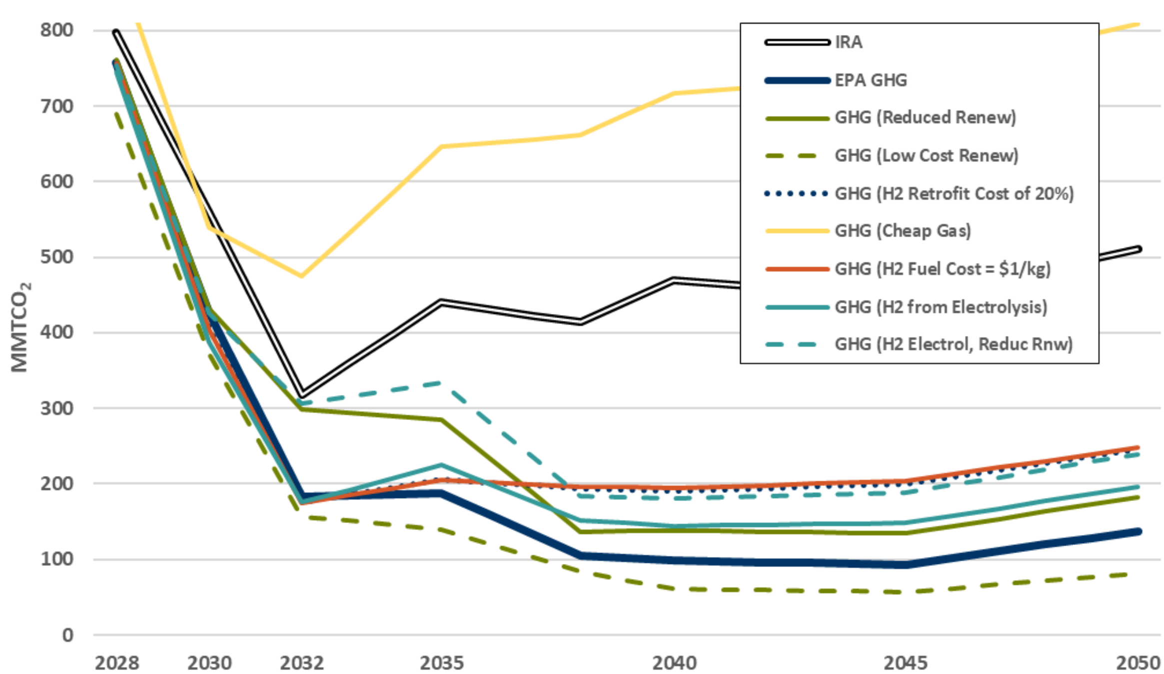
Figure 37 breaks the cumulative values of the IRA credits in the previous graph into groups based on the type of generation. Highlights of these findings include the following:

- Overall credit values are around $450 billion in today's dollars for the standard IRA scenario. Although using renewables cost assumptions from the ATB 2022 alter the mix and timing of renewable construction, overall outlays would have been only slightly higher as the result of additional renewables investment when using the lower assumed ATB 2022 costs.
- Nuclear production tax credits represent 20% of the total in the main IRA cases but can rise to 30% of the total in some sensitivity runs (total dollar values remain largely constant).
- Low gas prices, which significantly reduce construction of renewables, limit the numbers of credits claimed—thus, total IRA outlays are 26% lower than in the main IRA case.
- More limited access to renewables sites also reduces credits awarded, mainly those for onshore wind. When combined with cheap gas, credits for both solar and wind are reduced.

Emissions Under EPA Proposal for GHG

In all subsequent cases, the results for the EPA GHG Proposal are layered on top of the impacts of the IRA. As with previous runs, for comparison purposes the IRA tax credits are

Figure 38. Emissions of CO_2 under EPA GHG proposal



Source: DIEM model

not eliminated based on emissions levels through 2032, regardless of whether emissions in a particular model run may fall below the IRA cutoff level.

Figure 38 compares the main IRA emissions results to those from a range of emissions trends that vary assumptions regarding the EPA GHG proposal. Across all the scenario sensitivities, emissions fall significantly as the result of the EPA GHG proposal, based on a combination of additional coal CCS and hydrogen cofiring in gas turbines (and additional increases in renewables). Because of the proposal's expanded renewable generation, altering the availability or cost of renewables will impact overall emissions. As seen in previous types of scenarios, the availability of low-priced gas has the potential to significantly increase emissions by discouraging renewables and encouraging the retirement of nuclear plants when their IRA incentives expire. Were the hydrogen price to hold at $1/kg ($7.4/MMBtu), it would effectively remove most of the motivation to burn hydrogen. A high hydrogen price instead leads to shifting among the different sizes of combined-cycle units in order to avoid hydrogen requirements (Figure 38). In a high-priced hydrogen outcome, emissions remain steady at the levels achieved in 2032, but do not decrease further in response to the expanded hydrogen co-firing requirements beginning in 2038.

The final two sensitivities in the list for Figure 38 include the endogenous production of clean hydrogen from electrolysis within the electricity system itself—in this circumstance the generating resources used to provide the electricity needed for electrolysis compete with other generators supplying overall grid demands. As was shown in Figure 11, the amount of electricity potentially used for hydrogen electrolysis can represent a significant share of overall electricity demand. This increase in the total necessary generation results in an increase in emissions compared to the main EPA GHG scenario (where hydrogen is implicitly supplied by either sources outside the electricity sector or through renewable resources that would not have otherwise been able to contribute to generation for grid demands). Electrolysis raises emissions by the most in an environment where access to renewables is restricted through additional setbacks, land exclusions, or opposition to renewables development.

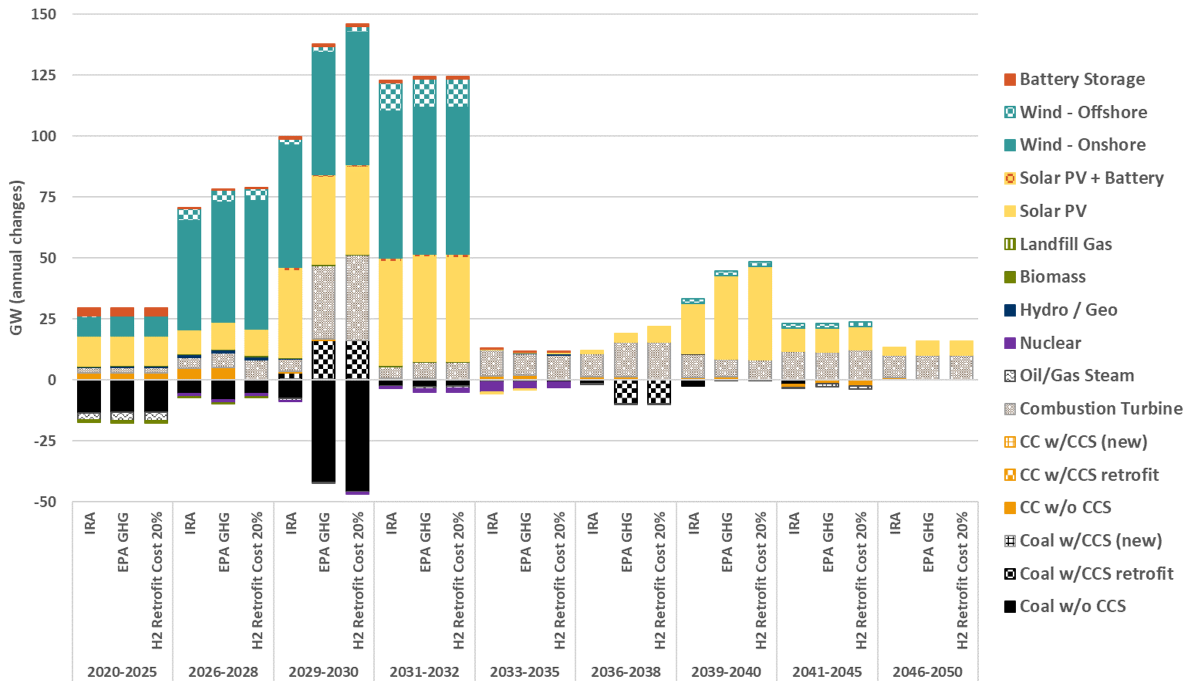
Capacity and Generation Changes Under the EPA GHG Proposal

Unlike the EPA RIA analysis (EPA 2023a) that showed essentially no new renewables from the EPA GHG proposal,[37] the DIEM analysis suggests that renewable capacity will increase in response to the EPA GHG proposal. Figure 39 compares the main IRA findings on annual capacity additions by time period to those of two alternative sets of assumptions regarding the GHG proposal: one case that uses the main set of modeling assumptions (EPA GHG), and the other that assumes there are capital costs associated with retrofitting gas units to co-fire hydrogen: Highlights of the capacity additions include:

[37] In the EPA analysis, coal CCS also did not increase; however, gas CCS did. The main adjustment to capacity investments seen in the EPA modeling was an increase in number of combustion turbines.

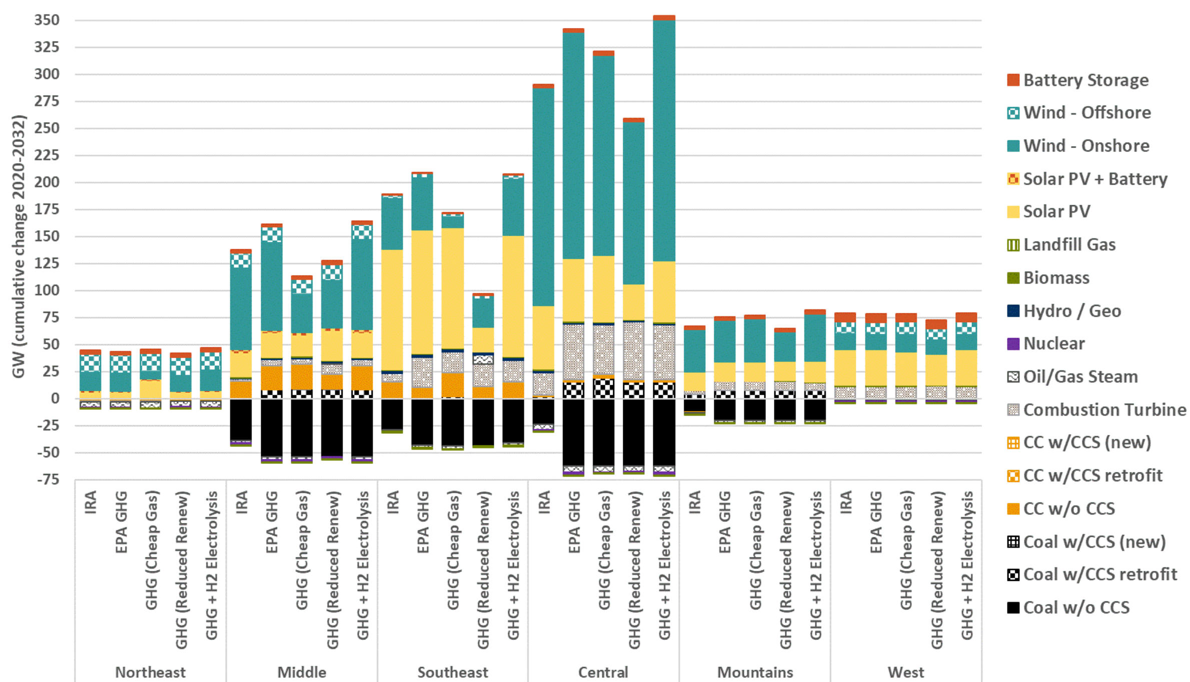
[38] As with other capacity change graphs, coal plants that retrofit with CCS appear as a positive number in the Coal w/CCS Retrofit category and a corresponding decline in the Coal w/o CCS category.

Figure 39. US annual capacity change: IRA versus EPA GHG versus GHG with H_2 retrofit costs



Source: DIEM model

Figure 40. Cumulative regional capacity changes through 2032: IRA versus EPA GHG



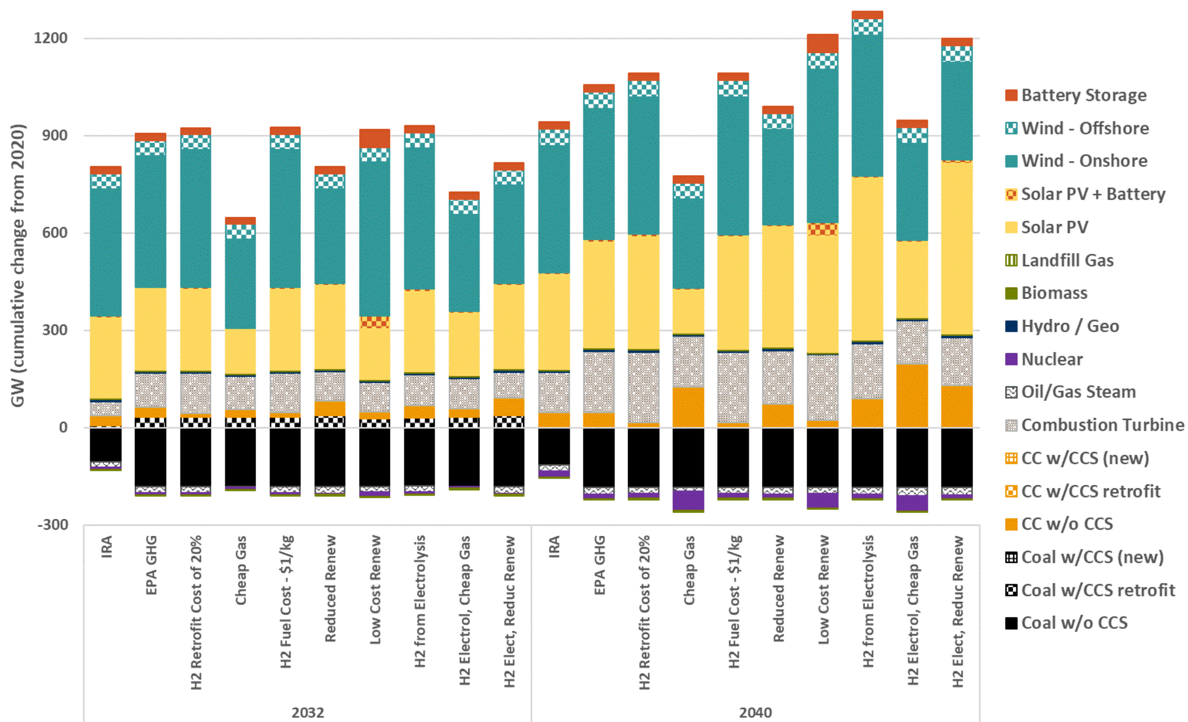
Source: DIEM model

- CCS retrofits of existing coal plants are increased significantly because of the EPA GHG proposal, timed to both take advantage of the IRA CCS credits and to meet the proposal's CCS requirements for units that intend to operate after 2040 (typically the newest, largest, and most efficient units).[38]
- Overall renewable installations are higher by 2030 as the result of the EPA GHG proposal. Onshore wind installations, in particular, are up to 30 GW higher than with IRA by itself.
- If combined-cycle units face an extra 20% in capital costs associated with hydrogen co-firing, no new units are added to the existing fleet.

Figure 40 contrasts the main IRA results for cumulative capacity additions/retirements from 2020 to 2032 with those of several alternative formulations of the EPA GHG scenarios. Highlights at the five-region level include the following:

- Similar to other scenarios, the EPA GHG proposal tends to concentrate the additional renewables in the middle sections of the country, rather than the coasts.
- When attempting to respond to the EPA GHG proposal, the Southeast is especially sensitive to any potential reductions in the availability of renewables in the GHG (Reduced Renew) scenario.
- The Southeast and Central regions add more new combustion turbines because of the

Figure 41. US cumulative capacity changes from 2020 to 2032/2040



Source: DIEM model

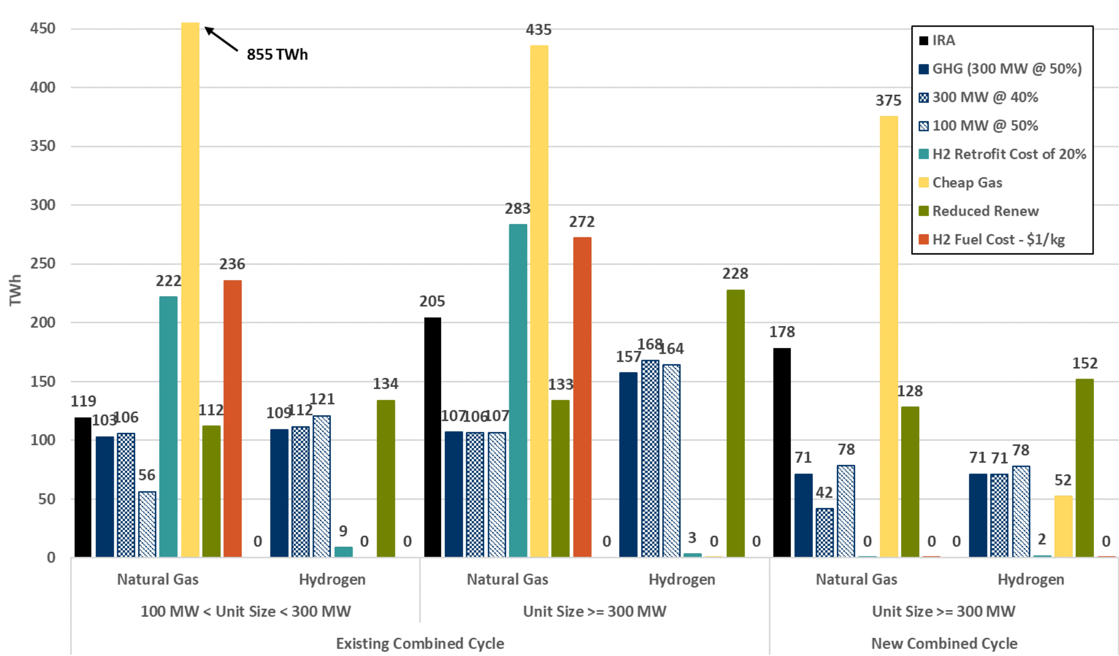
GHG proposal than other areas, partly to provide reliability services in a system with more renewables and fewer combined-cycle units than under the IRA.

- All regions install additional capacity if hydrogen is produced through electrolysis, with the largest increases coming through new onshore wind capacity in the middle of the country.

Figure 41 compares the cumulative changes in capacity for an early year of the EPA GHG proposal requirements (2032) with a year in which the requirements are fully in effect (2040). Highlights across a range of potential futures under the EPA GHG proposal include the following:

- In 2032, there are modest increases in solar and onshore wind compared to the IRA, but the largest impacts are on combustion turbines that operate outside of the GHG criteria and on coal with carbon capture.
- By 2032, an assumption that hydrogen needs to be produced through electrolysis using resources that compete with other electricity uses leads to more onshore wind, but modestly lower combustion turbine installations.
- By 2040, when the EPA GHG proposal is fully implemented, solar PV capacity is around 35 GW higher than under the IRA (most of the available cost-effective onshore wind has already been added, although there is still an increase of 13 GW).
- By 2040, the potential role of competition between electricity for the grid and

Figure 42. Shifts in combined-cycle generation in response to EPA GHG assumptions (2038)



Source: DIEM model

electricity for hydrogen electrolysis is highlighted. There are large increases in combined cycle and solar capacity to meet endogenous electrolysis needs, compared to the main EPA GHG scenario where hydrogen production does not compete with the grid.

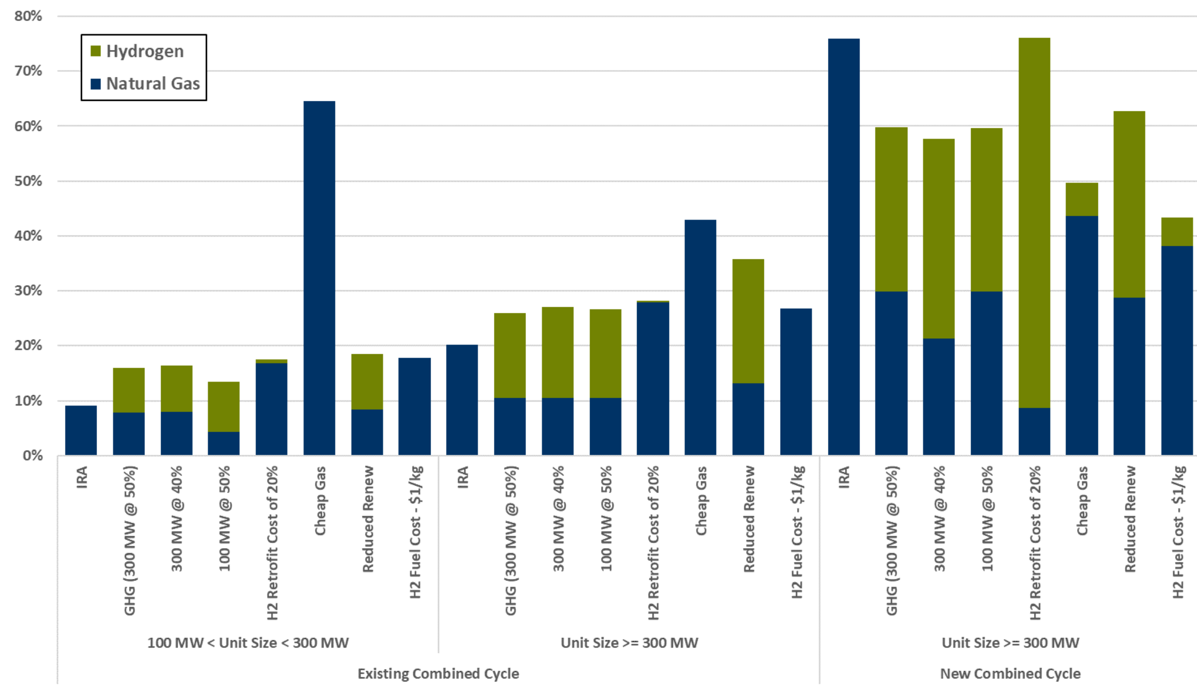
Figure 42 explores how the system may shift generation patterns by gas combined-cycle units in an attempt to avoid the EPA GHG proposal criteria when the final hydrogen requirement of 96% cofiring is applied in 2038. The results contrast how much electricity is generated by existing and new units by size category for a range of EPA GHG assumptions compared to the IRA without any specific criteria related to gas generation. Findings are distinguished by unit size and type of fuel (gas versus hydrogen).[39] Highlights of the results include the following:

- Compared to IRA generation, existing turbine units in the main GHG 300 MW @ 50% scenario drop their gas generation but add even more hydrogen generation, leading to a total increase from existing combined-cycle units. (Note that in the main GHG scenario, assumed hydrogen prices are lower than gas prices for many regions, thus, even units below 300 MW are incentivized to use hydrogen.) This increase in generation from existing units means that less generation from new combined-cycle units is needed.
- There are few impacts on generation from adjusting the proposal's utilization-rate criteria from 50% to 40%. Lowering the size criteria from 300 MW to 100 MW cuts gas generation by small units in half, with a slight increase in hydrogen co-firing at these smaller units.[40]
- The assumption that units would need capital investments in order to cofire hydrogen eliminates all hydrogen consumption at existing units, even if the hydrogen price (at $0.5/kg) is roughly comparable to natural gas prices. As will be seen in the next figure, the preferred response is to avoid the need for these capital expenditures by remaining below a 50% utilization rate. A few new units are still built that can burn hydrogen, but they are used infrequently.
- Cheap gas causes large increases in gas generation as might be expected, however, the size of units involved is altered from the IRA. While all units generate more, the biggest impact is on units below 300 MW since they do not face the 50% utilization rate criteria. Generation increases from 119 TWh under IRA to 855 TWh under the GHG proposal (off the scale of the graph). Note, however, that there may be inefficiencies involved in this shift as these units generally have worse heat rates than larger units.
- With cheap gas, existing units above 300 MW double their generation relative to IRA levels but are more constrained by the utilization constraints (none of the existing gas units burn any hydrogen when gas is cheap, so they have to run less than 50% of the time).
- Reduced availability of renewables increases gas generation across all categories, but has

[39] Unit size estimates are based on the EPA (2023b) guidelines memo as calculated for a consortium of states by ICF Consulting.

[40] Generation by gas units below 100 MW is quite small and does not vary much across the scenarios shown.

Figure 43. Average utilization rates in response to different EPA GHG assumptions (2038)



Source: DIEM model

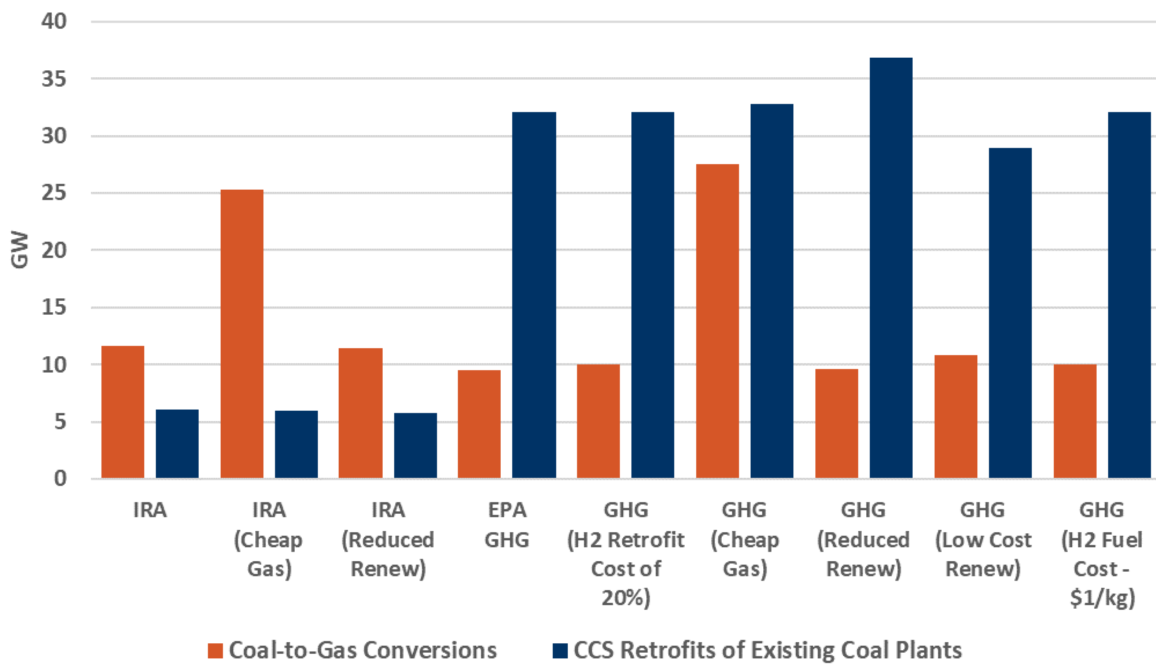
the largest effects on installations of and generation from new combined-cycle units.

Figure 43 presents the average utilization rates for the different types of combined cycle units shown in Figure 42, broken down into the shares represented by gas and hydrogen consumption. The first blue bar in each category shows utilization rates under the IRA (where hydrogen is assumed to remain at $1/kg and thus be uneconomic compared to natural gas). Note that these are average rates across the groups as of 2038—because these are overall averages across units that are operating both above and below the 50% rate threshold, the hydrogen share of total utilization does not have to equal the 96% cofiring requirement. Highlights of the rates across the other alternative scenarios include the following:

- Aside from new combined-cycle units, older units were already operating below 50% on average under the IRA by 2038, regardless of size.
- The relative cost of hydrogen again has the largest impact, as it did with total generation by size category. If hydrogen is expensive or requires capital improvements for cofiring, there is no hydrogen consumption by most gas units, other than a small

[41] Adopting 40% gas cofiring for units retiring between 2035 and 2040 is not an option selected by any of the units in the modeling. This action is assumed to potentially require the construction of new pipelines for units not already connected to the gas network. Costs associated with this new pipeline option (EPA 2023c) are significant.

Figure 44. Coal plant retrofits by 2030—Coal-to-Gas and CCS (IRA versus EPA GHG proposal)



Source: DIEM model

amount by new units that would normally wish to operate at close to their maximum capacity.

- Only minor shifting occurs in response to alterations in the EPA GHG proposal's criteria regarding unit size or utilization rate.
- Limitations on renewables increase utilization of both gas and hydrogen across the categories.

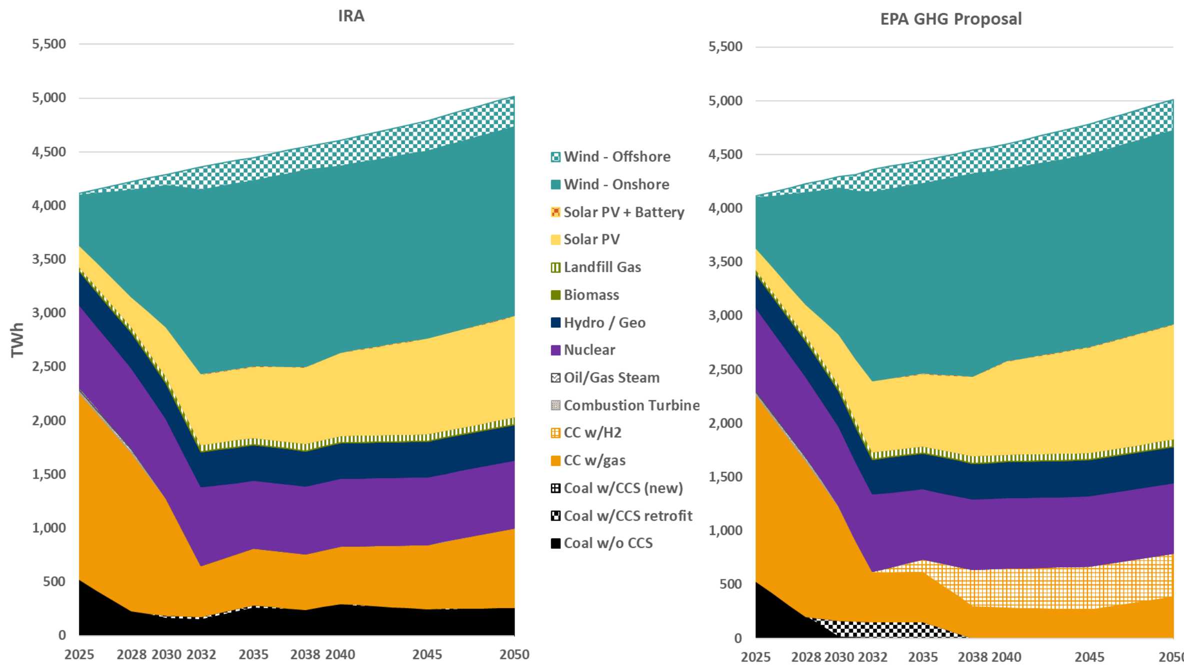
Moving on to coal plant responses to the EPA GHG proposal (other than retirement), Figure 44 looks at their retrofit options.[41] The two options chosen by most units that aren't intending to retire by 2040 are either to convert to a steam gas unit (with additional capital costs, a 33% reduction in fixed O&M costs, and a 5% heat rate penalty) and avoid the EPA GHG proposal's criteria, or add a CCS retrofit. Highlights include the following:

- Few units attempt to avoid CCS requirements by converting to steam gas, unless gas prices are low.
- The EPA GHG proposal encourages significantly more coal plants to add CCS than did so under IRA (no gas plants retrofit with CCS under any of the scenarios shown). These retrofits contribute a large share of the initial emissions reductions seen for the GHG proposal.

Table 5. EPA GHG carbon transport and storage quantities and average costs (in 2032)

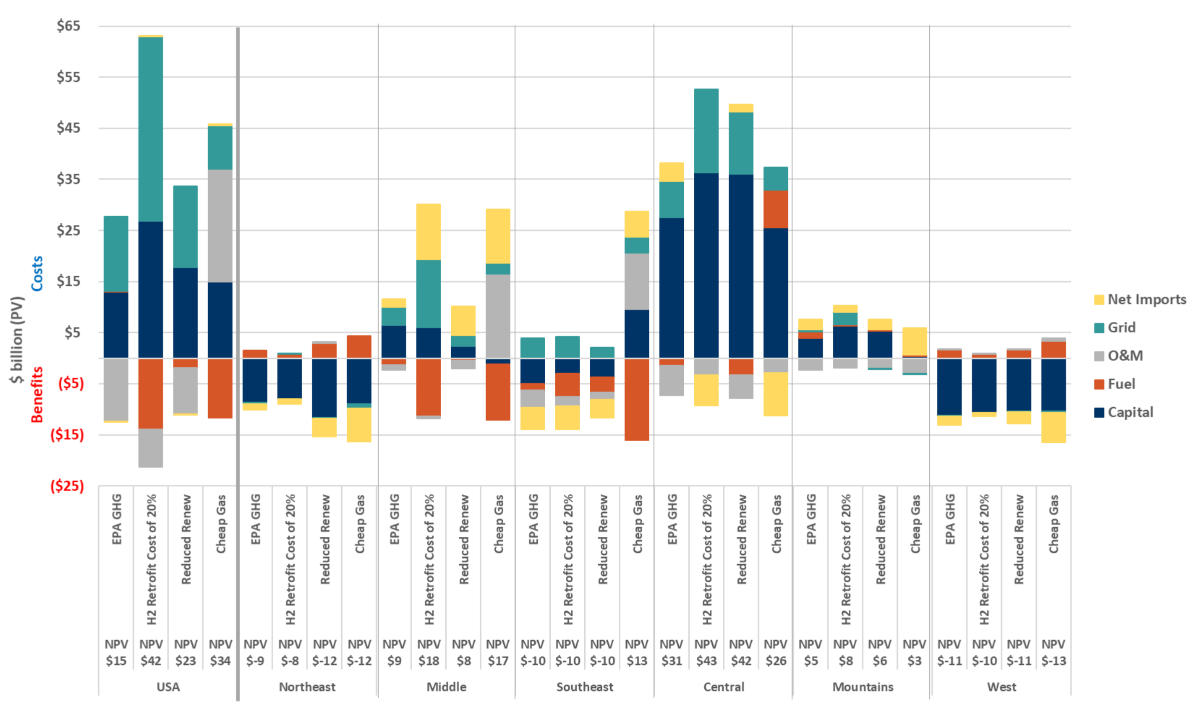
Origin State	Destination Location	Quantity, ($MMTCO_2$ annually)	Transport Cost, $/ton	Storage Cost $/ton	Total Cost, $/ton
Arizona	New Mexico	6.4	$13.3	-$29.3	-$16.0
Colorado	Colorado	2.7	$12.6	-$13.0	-$0.4
	New Mexico	0.6	$30.8	-$29.3	$1.6
Illinois	Illinois	10.7	$15.2	$9.8	$24.9
Indiana	Indiana	14.6	$12.7	$9.8	$22.5
Kansas	Oklahoma	9.2	$31.6	-$29.3	$2.3
Kentucky	Indiana	3.1	$14.7	$9.8	$24.5
Louisiana	Louisiana Offshore	3.3	$24.3	-$29.3	-$5.0
	Louisiana Onshore	11.0	$13.4	-$29.3	-$15.9
Maryland	Maryland	1.0	$11.0	$9.8	$20.8
Michigan	Michigan	4.1	$12.5	$9.8	$22.3
Missouri	Tennessee	3.1	$17.5	$9.8	$27.3
Montana	Montana	0.8	$21.7	-$29.3	-$7.6
Nebraska	Kansas	3.1	$32.7	-$29.3	$3.4
North Dakota	Montana	0.6	$31.7	-$29.3	$2.4
Oklahoma	Oklahoma	3.3	$25.6	-$29.3	-$3.7
South Dakota	Montana	0.3	$24.4	-$29.3	-$4.9
	North Dakota	2.7	$19.7	-$29.3	-$9.6
Texas	Texas Onshore	64.7	$22.9	-$29.3	-$6.4
Utah	Utah	14.2	$10.8	$3.7	$14.5
Wisconsin	Michigan	5.4	$19.5	$9.8	$29.3
West Virginia	Ohio	4.5	$15.3	$9.8	$25.0
	West Virginia	14.8	$14.1	$9.8	$23.9
Wyoming	Wyoming	22.1	$11.4	$4.0	$15.5
USA	**USA**	**206.2**	**$18.0**	**-$11.6**	**$6.4**

Figure 45. US generation: IRA versus EPA GHG



Source: DIEM model

Figure 46. System cost change in NPV through 2050 (compared to IRA scenarios)



Source: DIEM model

Table 5 gives the state locations of the coal plants that retrofit with CCS and the destinations where plants in each state send their captured CO_2 for storage. As was true for the IRA, most CO_2 is used for enhanced oil recovery, shown by the negative storage costs. Transport generally occurs with the state of origin or to nearby locations, reducing these charges and leaving total costs low (even before considering the credits received under IRA). Once the IRA credits for each unit expire, they generally prefer retirement to continued operation, even if they have already absorbed the retrofitting costs and the transport and storage costs are low. Additional incentives or broader climate policies would be needed for the coal CCS retrofits to continue generating by around 2040.

As with the findings for the IRA, generation patterns follow the capacity changes discussed previously. Highlights include the following:

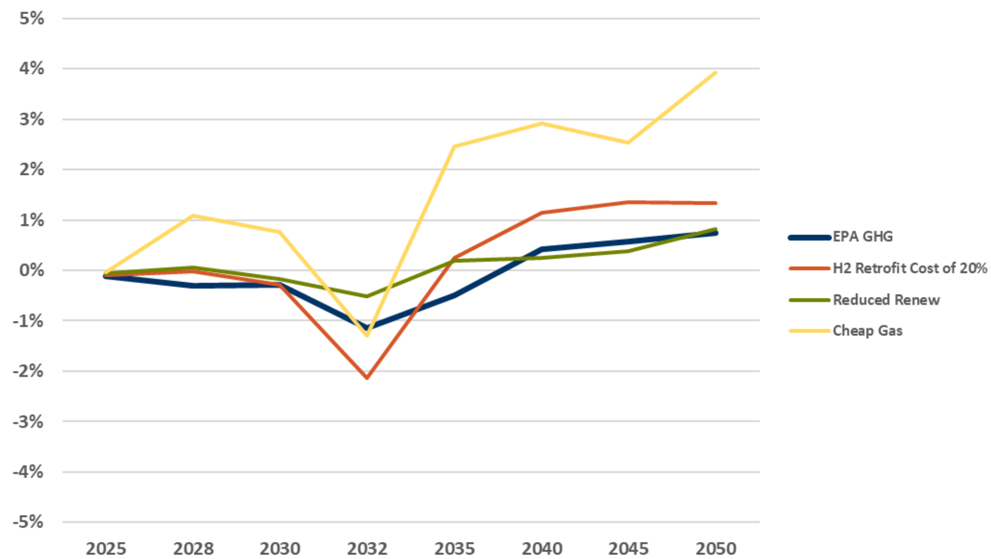
- Coal plants originally intending to retire prior to 2040 are likely to do so by 2030 to avoid taking any additional actions (assuming that these actions due not extend the lifespan of a unit).
- Coal plants that retrofit with CCS generate more than under IRA, but do not continue through 2050.
- Hydrogen cofiring accounts for more than one half of the combined-cycle generation as a whole between 2038 and 2045. Only higher demands as the economy approaches 2050 are enough to reverse this trend.
- Both wind and solar see modest increases in total generation from the EPA GHG proposal.

Costs Under the EPA Proposal for GHG

Costs per ton of emissions reduced were presented in Figures 7 and 8. Figure 46 looks at the overall expenditures needed in the electricity system to meet the GHG proposal requirements, compared to expenditures that have already occurred in implementing the IRA. Cost components are similar to those discussed in Figure 36 for the IRA; however, any alterations in the number of IRA credits received are not shown to concentrate on the expenditures made by generators. An overall net present value across the components is listed below the scenario label. Highlights of the findings include the following:

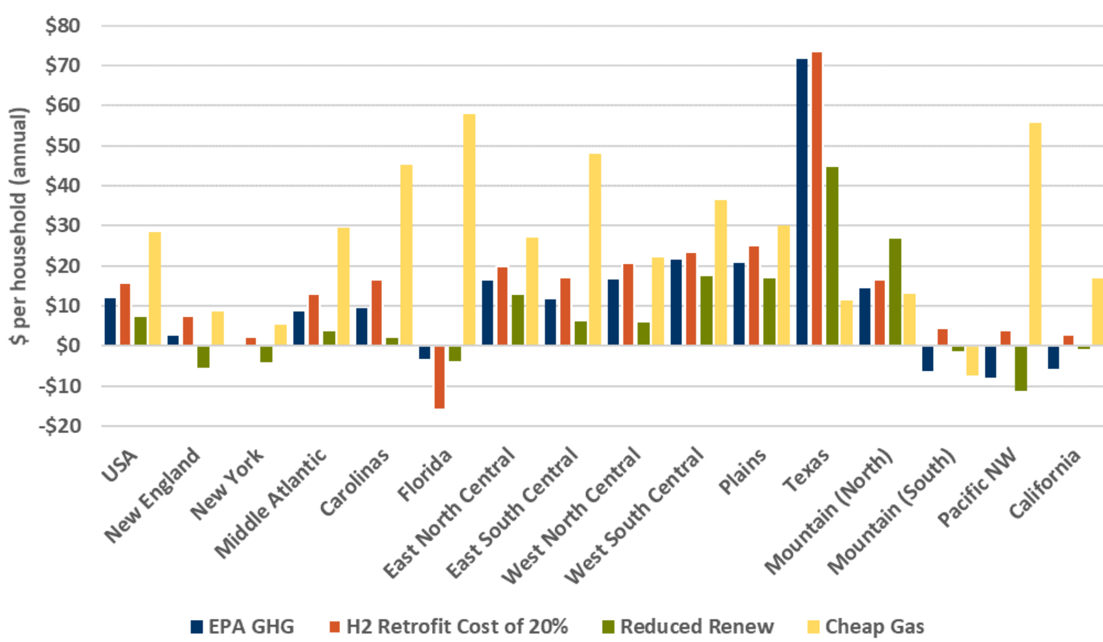
- For the United States as a whole, fuel expenditures are essentially unchanged given that hydrogen at $0.5/kg is not far from the alternative natural gas prices. This national finding does obscure some regional shifts in fuel expenditures as more coal and hydrogen are used, along with less gas.
- There is a modest increase in NPV costs for the country as a whole ($15 billion), but expenditures by coastal states and in the southeast decline slightly.
- Net system costs increase by the most in the Central states for the main GHG scenario, as the result of additional capital expenditures for renewables and coal-plant retrofits with CCS.
- If there are costs associated with retrofitting gas plants to burn hydrogen (or building new gas units that can burn hydrogen), overall costs are the highest across the

Figure 47. Changes in US electricity prices from EPA GHG proposal and sensitivities



Source: DIEM model

Figure 48. Changes in household bills from EPA GHG proposal (2038)



Source: DIEM model

scenarios. This option involved more significant shifting of gas generation among units to avoid using hydrogen.

- The availability of cheap gas (in both the GHG scenario and the IRA scenario against which these incremental costs are measured) also involves a large shifting in generation patterns, which leads to additional costs compared to the main GHG scenario.
- Restricted use of renewable resources causes an increase in potential costs from $15 billion to $23 billion, but total emissions are much higher in this case.

Figure 47 looks at relative changes in US average annual retail electricity prices for the EPA GHG sensitivities from Figure 46. Most scenarios have price impacts, either declining or rising, of less than 1% across all years. The two scenarios with the most direct effect on gas generation—whether through hydrogen retrofit costs that discourage gas consumption or low-priced gas that encourages gas use—can see higher relative prices by 2035–2038.

Figure 48 expresses the impacts as dollar changes in residential household bills, focusing on 2038 when the policy is in full effect. For most sensitivities, US costs average around $10 per household in 2038. However, as with other findings, regional impacts may vary. Aside from the Cheap Gas scenario, most states other than in the center of the nation have costs (or benefits) of $10 per household, in line with national averages. Central states can have costs closer to $20 per household, aside from Texas with higher impacts (in 2035, however, Texas sees the largest drops in household electricity bills). The Cheap Gas scenario exhibits the largest regional variation in costs.

NEXT STEPS

There remain a wide range of additional types of IRA and EPA GHG scenarios that can be investigated. Among potential options related to these policies are:

1. Reevaluating implications based on any updates to the EPA GHG proposal's criteria. After the EPA considers the comments received based on their initial May 2023 proposal, revisions to some of its criteria may occur. Once these alterations are specified, this analysis can incorporate any new EPA assumptions regarding types of units, unit sizes, utilization rates, and market conditions used in any new RIA.
2. Examining potential trading schemes among states for the current EPA GHG proposal. Depending on the final EPA criteria, the potential exists that states may be able to take advantage of flexibility mechanisms such as were included in EPA's initial Clean Power Plan from 2017. These mechanisms allowed states to trade emissions permits across units within states and across state borders to achieve emissions goals on average across all affected units, but at lower costs.
3. Investigating additional interactions with electrification. Many industry trends could lead to additional electricity demand, whether manufacturing electrification or data centers or more rapid adoption of electric vehicles. All of these will have implications for emissions and the types of investments needed to provide for future growth.

4. Evaluating future hydrogen markets in more depth on both the demand and supply sides. A range of issues related to transport and storage have also been assumed away in this analysis.
5. Exploring impacts of a lack of CO_2 storage options, whether due to reluctance on the part of generators to invest in the technology or communities to allow nearby storage. Many of the current emissions reductions associated with the EPA GHG proposal are a function of CCS adoption.

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