2021 Standard Scenarios Report: A U.S. Electricity Sector Outlook

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Contributing Authors: Maxwell Brown, Patrick Brown, Stuart Cohen, Kelly Eurek, Will Frazier, Pieter Gagnon, Nick Grue, Jonathan Ho, Anthony Lopez, Trieu Mai, Matthew Mowers, Caitlin Murphy, Brian Sergi, Dan Steinberg, and Travis Williams

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Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-6A40-80641
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Suggested Citation
Cole, Wesley, J. Vincent Carag, Maxwell Brown, Patrick Brown, Stuart Cohen, Kelly Eurek, Will Frazier, Pieter Gagnon, Nick Grue, Jonathan Ho, Anthony Lopez, Trieu Mai, Matthew Mowers, Caitlin Murphy, Brian Sergi, Dan Steinberg, and Travis Williams. 2021. *2021 Standard Scenarios Report: A U.S. Electricity Sector Outlook*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-80641. https://www.nrel.gov/docs/fy22osti/80641.pdf.

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303-275-3000 • www.nrel.gov

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Preface

This report is one of a suite of National Renewable Energy Laboratory (NREL) products aiming to provide a consistent and timely set of technology cost and performance data and define a scenario framework that can be used in forward-looking electricity analyses by NREL and others. The long-term objective of this effort is to identify a range of possible futures for the U.S. electricity sector that illuminate specific energy system issues. This is done by defining a set of prospective scenarios that bound ranges of technology, market, and macroeconomic assumptions and by assessing these scenarios in NREL's market models to understand the range of resulting outcomes, including energy technology deployment and production, energy costs, and emissions.

This effort, which is supported by the U.S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy (EERE), focuses on the electric sector by creating a technology cost and performance database, defining scenarios, documenting associated assumptions, and generating results using NREL's Regional Energy Deployment System (ReEDS) model and the Distributed Generation Market Demand Model (dGen). The work leverages significant activity already funded by EERE to better understand individual technologies, their roles in the larger energy system, and market and policy issues that can impact the evolution of the electricity sector.

Specific products from this effort include:

- An Annual Technology Baseline (ATB) workbook documenting detailed cost and performance data (both current and projected) for both renewable and conventional technologies
- An ATB summary website describing each of the technologies and providing additional context for their treatment in the workbook
- This Standard Scenarios report describing U.S. power sector futures using the Standard Scenarios modeling results.

These products can be accessed at atb.nrel.gov and www.nrel.gov/analysis/standard-scenarios.html.

These products are built and applied to analyses to ensure (1) the analyses incorporate a transparent, realistic, and timely set of input assumptions, and (2) they consider a diverse set of potential futures. The application of standard scenarios, clear documentation of underlying assumptions, and model versioning is expected to result in:

- Improved transparency of modeling input assumptions and methodologies
- Improved comparability of results across studies
- Improved consideration of the potential economic and environmental impacts of various electric sector futures
- An enhanced framework for formulating and addressing new analysis questions.

Future analyses under this family of work are expected to build on the assumptions used here and provide increasingly sophisticated views of the future U.S. power system with the potential to expand to other sectors of the U.S. energy economy.

Acknowledgments

We gratefully acknowledge the many people whose efforts contributed to this report. We thank Billy Roberts for creating the maps used in this work. We are grateful to comments from Doug Arent, Peter Balash, Sam Bockenhauer, Steve Capanna, Jaquelin Cochran, Brent Dixon, Zach Eldredge, Carey King, Imran Lalani, Chris Namovicz, Kara Podkaminer, Gian Porro, Nicole Ryan, Paul Spitsen, and Rich Tusing. The effort reported here was funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy Strategic Analysis Team, under contract number DE-AC36-08GO28308. All errors and omissions are the sole responsibility of the authors.

List of Acronyms

AC	alternating current
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BNEF	BloombergNEF
CC	combined cycle
CCS	carbon capture and storage
CO_2	carbon dioxide
CSP	concentrating solar power
CT	combustion turbine
DAC	direct air capture
DC	direct current
dGen	Distributed Generation Market Demand Model
DOE	U.S. Department of Energy
EERE	DOE's Office of Energy Efficiency and Renewable Energy
EIA	U.S. Energy Information Administration
ERCOT	Electric Reliability Council of Texas
GW	gigawatt
GW_{AC}	gigawatt-alternating current
GWh	gigawatt-hour
HVDC	high-voltage direct current
LCC	line commutated converter
LCOE	levelized cost of energy
MMBtu	million British thermal units
MMT	MMT is million metric tons
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NG	natural gas
NG-CC	natural gas combined cycle
NG-CT	natural gas combustion turbine
NOx	nitrogen oxides
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
OGS	oil-gas-steam
PV	photovoltaic(s)
RE	renewable energy
RE-CT	renewable energy combustion turbine
ReEDS	Regional Energy Deployment System
TW	terawatt
TWh	terawatt-hour
TW-mi	terawatt-mile
VRE	variable renewable energy

Executive Summary

This report documents the seventh edition of the annual Standard Scenarios. It summarizes the results of 50 forward-looking scenarios of the U.S. power sector which have been designed to capture a wide range of possible power system futures.

The Standard Scenarios are simulated using the Regional Energy Deployment System (ReEDS) model which utilizes behind-the-meter solar adoption projections from the Distributed Generation Market Demand Model (dGen). The ReEDS model projects utility-scale power sector evolution for the contiguous United States using a system-wide, least-cost approach when making decisions. For select scenarios, the systems built by ReEDS and dGen are run using the PLEXOS production cost model to provide hourly outputs of system operation.

Scenario results are included as part of this report in the Standard Scenarios Results Viewer (see cambium.nrel.gov). Annual results are available for the full suite of scenarios, and hourly results are available for the subset of scenarios run in PLEXOS.

Previous editions of the Standard Scenarios report included a reference scenario (called the Mid-case) that uses default or median assumptions in the models. Because of increased interest in considering decarbonized power sector futures, we include the Mid-case with three levels of power sector decarbonization. The first (No New Policy) assumes no new carbon policies beyond those in place as of June 2021; the second (95% by 2050) assumes national power sector carbon dioxide (CO_2) emissions decrease linearly to 95% below 2005 emissions by 2050; and the third (95% by 2035) assumes national power sector CO_2 emissions decline to 95% below 2005 levels by 2035 and are eliminated on a net basis by 2050 (see Figure ES-1). The capacity and generation mixes for the Mid-case scenario under these three decarbonization trajectories are shown in Figure ES-2.

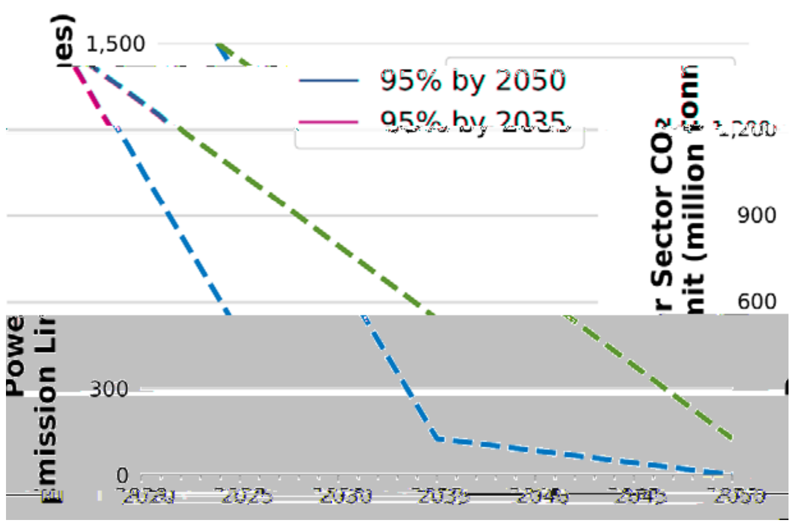


Figure ES-1. Power sector CO_2 emission limits over time for the 95% by 2050 and 95% by 2035 scenarios.

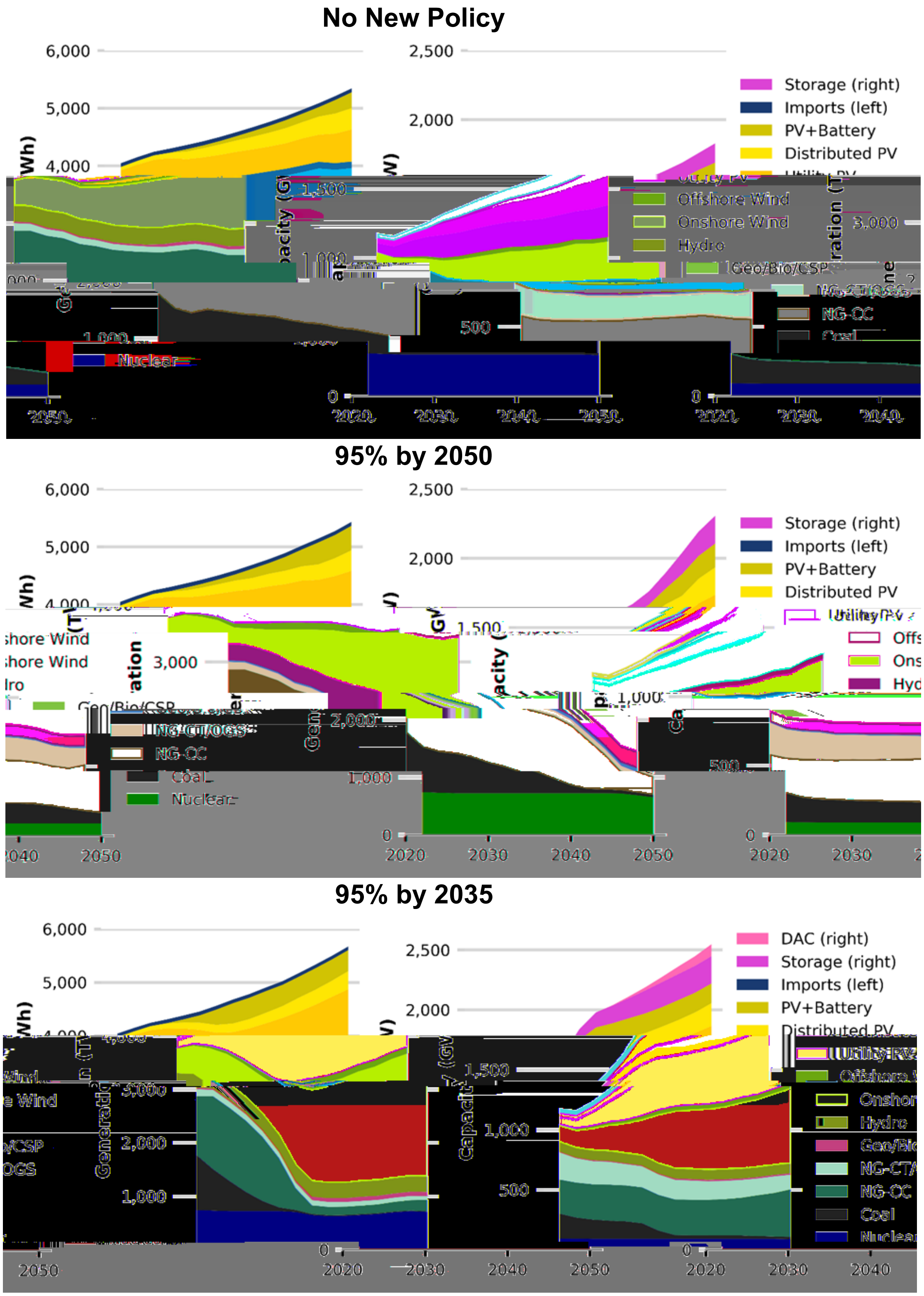
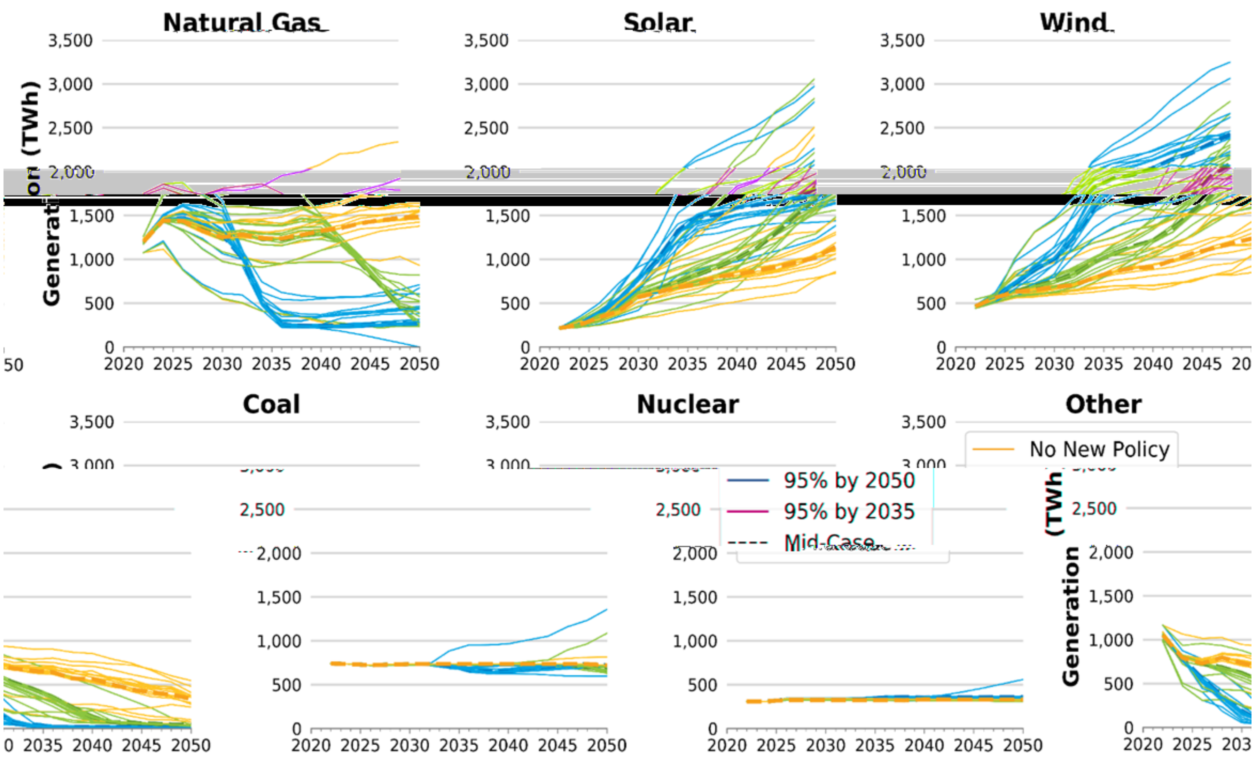


Figure ES-2. U.S. power sector generation (left) and capacity (right) over time for the three Mid-case scenarios from 2022 to 2050. NG-CC is natural gas combined cycle, NG-CT is natural gas combustion turbine, OGS is oil-gas-steam, Geo/Bio is geothermal and biopower, DAC is direct air capture, TWh is terawatt-hours, and GW is gigawatts. Biopower and NG-CC plants can include carbon capture and sequestration (CCS).

The Standard Scenarios also include 16 sensitivity scenarios that incorporate factors such as fuel prices, demand growth, technology costs, and transmission and resource conditions. Each sensitivity is performed for the three CO_2 emission limits applied to the Mid-case scenario,[1] resulting in a wide range of possible generation mixes (Figure ES-3).



This report summarizes many of the key scenario results and scenario assumptions. The scenarios are not meant to forecast or predict power sector deployment. Rather, our goal in providing the scenarios and associated outputs is to offer context, enable discussion, and provide data that can inform stakeholder decision making about the future evolution of the U.S. power sector.

[1] The No Carbon Removal sensitivity scenario is not included for the No Policy Mid-case because that scenario already does not result in the deployment of CO_2 removal technologies. This leads to a total of 50 scenarios (3 Mid-case emission scenarios + 16x3-1 sensitivity scenarios).

Table of Contents

List of Figures

List of Tables

1 Introduction

The U.S. electricity sector continues to undergo rapid change because of evolutions in technologies, markets, and policies. To help advance the understanding of the implications, drivers, and key uncertainties associated with this change, we are providing this seventh[2] installment of the Standard Scenarios. This year's Standard Scenarios consist of 50 power sector scenarios for the contiguous United States that consider the present day through 2050. The scenarios rely on two models from the National Renewable Energy Laboratory (NREL) along with a commercial production cost model:

- Regional Energy Deployment System (ReEDS): a long-term capacity expansion model from NREL (Ho et al. 2021)
- Distributed Generation Market Demand Model (dGen): a distributed generation diffusion model from NREL (Sigrin et al. 2016)[3]
- PLEXOS: a production cost model from Energy Exemplar.[4]

The Standard Scenarios enable a quantitative examination of how various assumptions could impact the future development of the power sector. The full suite of scenarios considers a wide range of assumptions.

The objective of this effort is not to predict the specific deployment trajectories for the various generator technologies but rather to consider a range of possible grid evolution pathways in an attempt to better understand key drivers, implications, and decision points that can contribute to better-informed investment and policy decisions. The Standard Scenarios are not forecasts, and we make no claims that our scenarios have been or will be more indicative of actual future power sector evolution than projections made by others. Instead, we note that a collective set of projections from diverse analytical frameworks and perspectives creates a robust basis to analyze drivers of change in the power sector and help inform decision making (Mai et al. 2013).

In addition, our modeling tools have been designed to capture the unique traits of renewable energy generation technologies and the resulting implications for the rest of the power system. We aim to accurately capture issues related to renewable energy integration, including capacity adequacy and interactions of curtailment and storage on investment decisions. Other modeling and analysis frameworks will have different emphases, strengths, and weaknesses. The work we report here provides a perspective on the electricity sector that complements those provided by others; it also demonstrates how the models operate under a variety of input conditions and configurations.

Although the models used to develop the Standard Scenarios are sophisticated, they do not capture every factor that can impact the evolution of each scenario. For example, the models do not explicitly represent supply chains, and ReEDS and PLEXOS take a system-wide planning approach when making decisions rather than representing specific market actors or rules.

[2] See atb.nrel.gov/archive for the previous Standard Scenarios reports and data.
[3] For more information about ReEDS and dGen, see www.nrel.gov/analysis/reeds and www.nrel.gov/analysis/dgen, respectively. For lists of published work using ReEDS and dGen, see www.nrel.gov/analysis/reeds/publications.html and www.nrel.gov/analysis/dgen/publications.html respectively.
[4] Only a subset of the scenarios was modeled in PLEXOS. Additional postprocessing of the PLEXOS results was performed to provide additional outputs such as marginal emissions rates.

Therefore, results should be interpreted within the context of model limitations. A more complete list of model-specific caveats is available in the models' documentation (Ho et al. 2021, Section 1.4; Sigrin et al. 2016, Section 2.2).

The ultimate purpose of the Standard Scenarios and this associated report is to provide context, discussion, and data to inform stakeholder decision-making regarding the future evolution of the U.S. power sector. As a key feature of this effort, the state-level Standard Scenarios outputs are presented in a downloadable format online using the Standard Scenarios Results Viewer (see cambium.nrel.gov). This report reflects high-level observations, trends, and analyses, whereas the Standard Scenarios Results Viewer includes detailed scenario results useful for more in-depth analysis.[5]

[5] The data viewer provides additional state-specific data from the scenarios; however, we note that as a national-scale model, ReEDS is not specifically designed to assess in detail the full circumstances of any individual state.

2 The Standard Scenarios

The 2021 Standard Scenarios comprise 50 power sector scenarios[6] that are run using the ReEDS model (Ho et al. 2021) and the dGen model (Sigrin et al. 2016). Scenario assumptions have been updated since last year to reflect the technology, market, and policy changes that have occurred in the power sector, and many modeling enhancements have been made (see Appendix A.2 for a complete list of changes).[7] The scenarios included in this report are summarized in Figure 1. Details about specific scenario definitions and inputs are provided in Appendix A.1.

The 50 scenarios were selected to capture a breadth of trajectories of costs, performance, and other drivers under various levels of power sector decarbonization.[8] The diversity of scenarios is intended to cover a range of potential futures rather than focus on a single-scenario outlook. For example, in addition to considering traditional sensitivities such as demand growth and fuel prices, we also assess a considerable number of other factors that can impact the development of the power system, such as transmission build-out and technology progress. We do not assign probabilities to these scenarios, nor do we posit which scenarios are more or less likely to occur.

This Standard Scenarios analysis also takes advantage of a tool that converts ReEDS scenario outputs into PLEXOS input data. PLEXOS is a commercially available production cost model that we use to model the hourly operation of a subset of scenarios. The ReEDS model uses a simplified hourly dispatch module coupled with a reduced-form dispatch representation (Ho et al. 2021); thus, by using a production cost model at hourly resolution, we can examine results with greater temporal resolution and can more fully capture the range of operational conditions and constraints that exists across the year. The scenarios that were modeled hourly also included additional outputs, such as long-run marginal emission rates, as facilitated by the Cambium tool (Gagnon et al. 2020).

We note that, to enhance transparency in model results, the ReEDS and dGen models and scenario input definitions we used to generate these scenarios are publicly available.[9]

[6] The Standard Scenarios focus specifically on the power sector. Interactions with other sectors are only lightly considered via sensitivities with high end-use electrification and increased demand-side flexibility.
[7] As of the time of this writing, a variety of federal power sector policies are being considered by the U.S. Congress. We do not attempt to capture any specific policy under consideration, but do include some general policy sensitivities such as tax credit extensions, carbon reduction targets, and end-use electrification.
[8] Although the scenarios cover a wide range of futures, they are not exhaustive. Additionally, the Standard Scenarios are not designed to analyze specific administration goals or targets (such as the Biden administration goal to decarbonize the power sector by 2035), and as such, analysis of specific goals has been left to separate work.
[9] See www.nrel.gov/analysis/reeds and www.nrel.gov/analysis/dgen/.

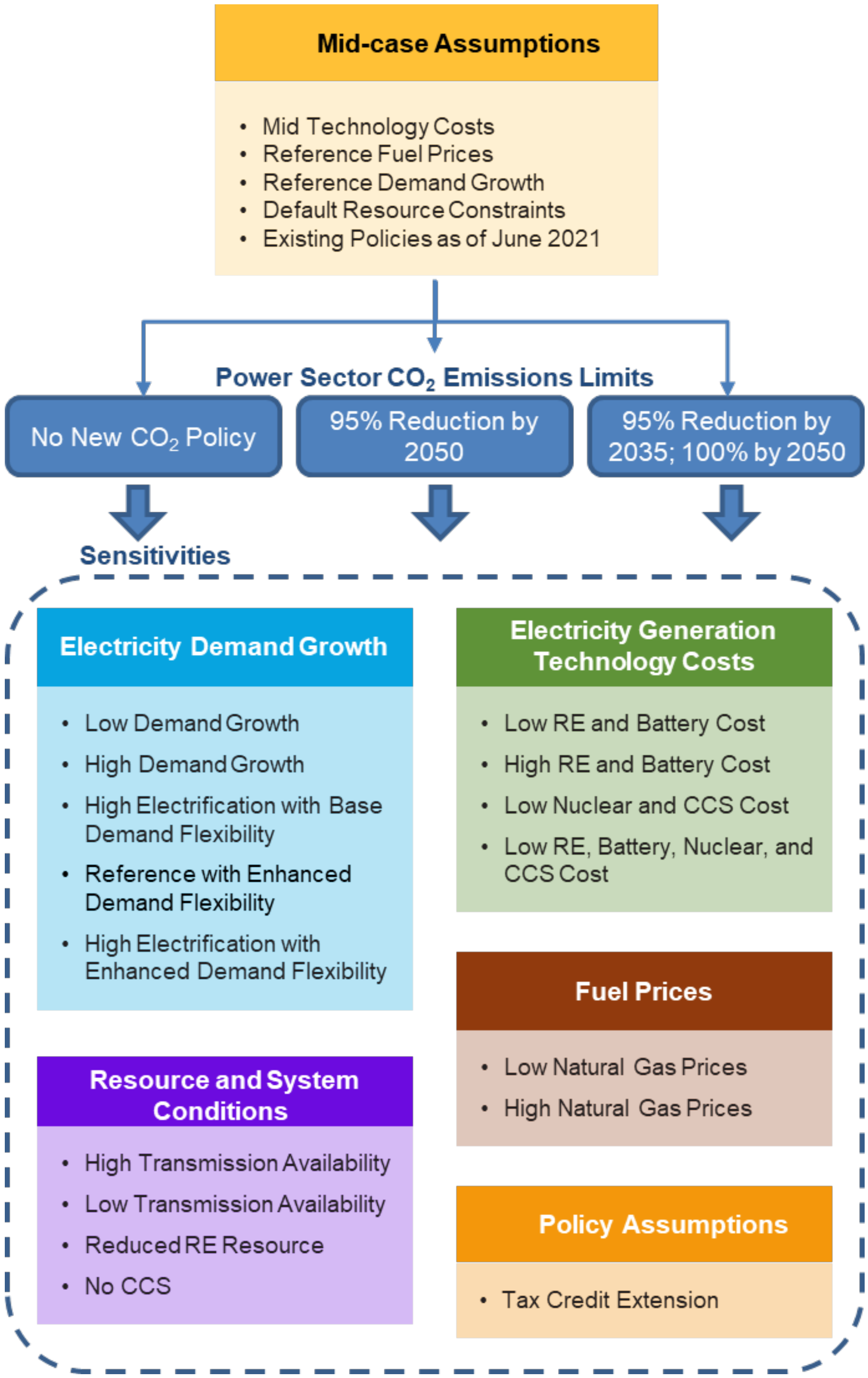


Figure 1. Summary of the 2021 Standard Scenarios. The Mid-case scenario is run using three different power sector CO_2 emissions limits. Sixteen sensitivities are applied to the Mid-case for each CO_2 emissions trajectory for a total of 50 scenarios (the No CCS[10] sensitivity is not applied to the No New Policy Mid-case because that scenario does not result in CCS, so there are 16 sensitivities x 3 emission trajectories – 1 + 3 emission trajectories for the Mid-case = 50 scenarios). Scenario details are in Table A-1 of the appendix. All scenarios reflect federal and state electricity policies enacted as of June 2021.

[10] CCS is carbon capture and sequestration.

3 The Mid-case Scenario

The Mid-case scenario uses the reference, mid-level, or default assumptions for demand growth, resource, system cost, fuel price, and technology inputs (see Figure 1 for a summary of those assumptions and Table A-1 and Appendix A.1 for details about the assumptions). In this way, the Mid-case scenario provides a reference point for comparing scenarios and assessing trends. Section 3.1 provides some additional context for how the Mid-case scenario relates to projections from other organizations.

Figure 2 shows the generation and capacity mix through 2050 for the Mid-case scenario using the three levels of power sector decarbonization. The No New Policy trajectory does not impose any CO_2 emission limit other than those already in place, the 95% by 2050 trajectory imposes a 95% reduction in national power sector CO_2 emissions[11] by 2050 relative to 2005, and the 95% by 2035 trajectory requires that national CO_2 emissions are reduced by 95% in 2035 and 100% in 2050 relative to 2005. The emission levels allow for negative emission technologies to offset stack emissions from carbon-emitting sources in order to meet the CO_2 emission limit.

With the increased requirements for emissions reduction comes increased renewable energy deployment, particularly from solar photovoltaics (PV) and wind. In 2050, PV capacity reaches over 500 GW_{AC} in the Mid-case with no new policy and about 800 GW_{AC} in the two Mid-case scenarios with emission limits.[12] Wind capacity grows to over 300 GW in the No New Policy Mid-case in 2050, and to around 600 GW in the two emission limit scenarios.

Uncontrolled fossil capacity remains in all three scenarios despite the stringent CO_2 limits.[13] The capacity persists by running at lower utilization rates and by offsetting emissions using negative emissions technologies such as biopower with carbon capture and sequestration (CCS) and direct air capture. These fossil resources, along with other resources such as nuclear, hydropower, and geothermal plants, provide an important source of firm capacity for periods with low wind and solar output. Firm capacity is especially important in the winter when solar resources are low and load tends to be high (Cole, Greer, et al. 2020).

Existing nuclear plants remain sufficiently competitive to avoid early retirement,[14] resulting in a near-constant level of nuclear capacity and generation through 2050. No new nuclear is added in the Mid-case scenario, even with stringent CO_2 limits.

Total generation is slightly higher in the lower emissions scenarios because of increased transmission and storage losses and the deployment of electricity-consuming direct air capture technologies.

[11] The emissions limit is applied to stack emissions rather than lifecycle emissions. The exception is biopower with carbon capture, where the biopower feedstock is assumed to be carbon neutral.
[12] PV capacity includes rooftop PV, utility-scale PV, and PV+Battery. In this work, PV+Battery plants are utility-scale PV plants that include a 4-hour battery rated at 50% of the size of the inverter (Eurek et al. 2021).
[13] There is also some CCS capacity built in the scenarios with a CO_2 limit. In 2050 the 95% by 2050 limit results ins 3% of annual generation from natural gas plants with CCS. See Figure 11 and Table 3 for additional details.
[14] Nuclear power plants have an assumed lifetime of 80 years within the model.

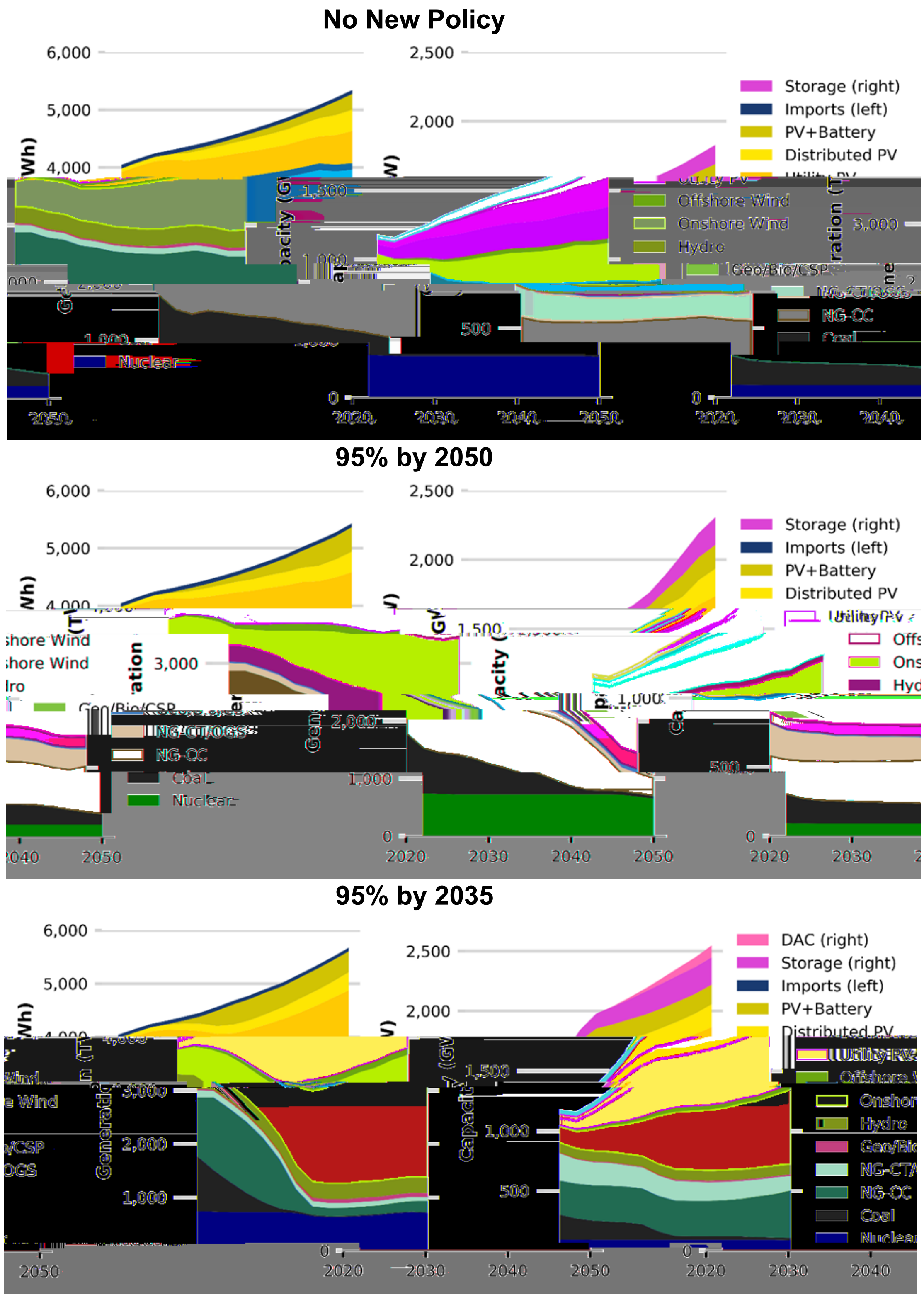


Figure 2. U.S. power sector generation (left) and capacity (right) over time for the Mid-case scenario under three levels of CO_2 requirements. Top: No Policy Mid-case, Middle: 95% by 2050 Mid-case, Bottom: 95% by 2035 Mid-case. NG-CC is natural gas combined cycle, NG-CT is natural gas combustion turbine, OGS is oil-gas-steam, Geo is geothermal, bio is biopower, CSP is concentrating solar power, and DAC is direct air capture. NG-CC, coal, and biopower can include CCS.

Table 1 and Table 2 show the generation fraction for the major fuel types in 2036 and 2050, respectively for the Mid-case scenario with different levels of CO_2 emission limits. In all cases, renewable energy technologies provide the majority of generation in both 2036 and 2050, but the shares vary considerably, especially as CO_2 emission limits are applied.

Table 1. Generation fraction in 2036 for each fuel type in the Mid-case scenario under three levels of CO_2 requirements.

Fuel Type	No New Policy	95% by 2050	95% by 2035
Total Renewable	42%	49%	80%
Wind	20%	23%	40%
Solar	16%	19%	32%
Nuclear	16%	16%	14%
Natural Gas	27%	27%	5%
Coal	14%	8%	0.4%

Table 2. Generation fraction in 2050 for each fuel type in the Mid-case scenario under three levels of CO_2 requirements.

Fuel Type	No New Policy	95% by 2050	95% by 2035
Total Renewable	52%	80%	82%
Wind	22%	40%	43%
Solar	23%	34%	32%
Nuclear	13%	12%	13%
Natural Gas	28%	7%	5%
Coal	6%	0.7%	0.2%

3.1 Comparison With Other Reference Case Scenarios

Here, we compare the No New Policy Mid-case projection with those from three well-known organizations—the U.S. Energy Information Administration (EIA), the International Energy Agency (IEA), and BloombergNEF (BNEF)—that have a longer record of producing annual U.S. electricity sector outlooks. Although NREL (via the Standard Scenarios) [15] and most of these organizations publish multiple scenarios that span a wide range of assumptions, this comparison uses only the "reference" scenarios. [16] Figure 3 shows results from the:

- NREL Standard Scenarios No New Policy Mid-case,
- EIA Annual Energy Outlook (AEO) Reference case,
- IEA World Energy Outlook Stated Policies scenario, and
- BNEF New Energy Outlook scenario.[17]

Figure

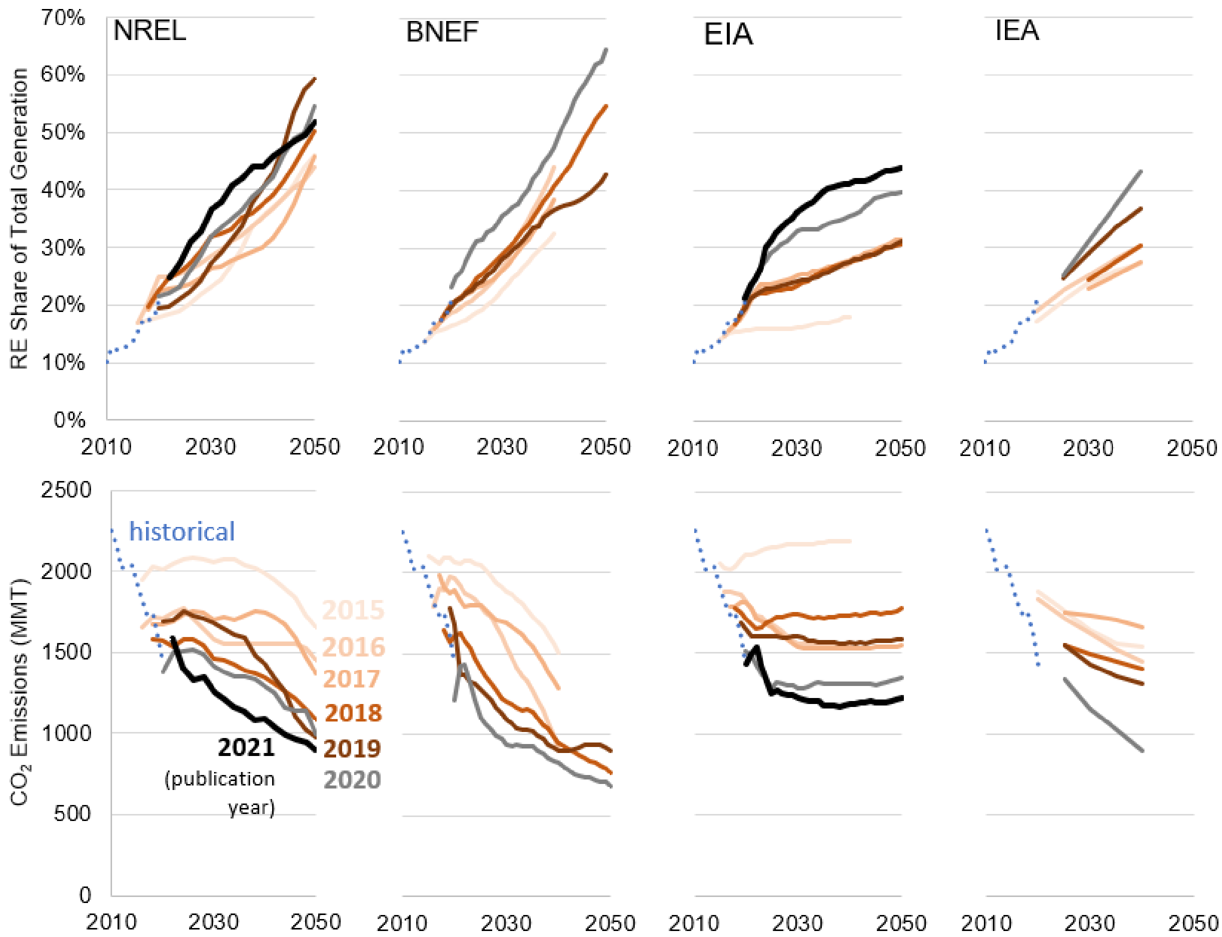


Figure 3. Renewable energy generation fraction (top) and power sector CO_2 emissions (bottom) from the organizations and publication years indicated. Only reference case scenarios are shown. MMT is million metric tons.

[15] The Standard Scenarios have been published since 2015.
[16] The input assumptions, including the policies represented may differ among these reference scenarios.
[17] The IEA World Energy Outlook 2021 and the BNEF New Energy Outlook 2021 were not yet available at the time of this writing. Note that reference case names have changed over time in the various publications.

All scenarios (from the organizations and publication years shown in Figure 3) show that the renewable energy generation fraction increases over time, where renewable energy includes technologies that use biomass, geothermal, hydropower, solar, and wind resources. For example, the range of renewable energy shares estimated from the most recent set of projections from the four organizations is 31%–37% in 2030, a narrow range of values that are all higher than the 21% share of renewable energy observed for 2020. This range widens over time to 44%–65% in 2050, highlighting growing divergence among the projections into the future.

Power sector CO_2 emissions results from this collection of scenarios reveals similarly wide variations among organizations and publication years, with 2050 CO_2 emission values of 683–1,226 million metric tons in the latest set of projections. The emissions trends are, of course, related to the renewable energy share but are also closely tied to the amount and mix of fossil fuel-fired generation and nuclear generation in the projections. For example, the latest BNEF projection shows a steadily increasing share of natural gas-fired generation that primarily offsets coal-fired generation, leading to the most-rapid and largest emissions reductions shown. In contrast, the EIA's 2021 Reference case projects slow growth for natural gas-fired generation and a modest decline in coal-fired generation after 2030. The 2021 Standard Scenarios No New Policy Mid-case results in a slight near-term rise in fossil fuel-based generation followed by a steady decline through 2050. For all organizations, more recent projections generally include lower power sector emissions than earlier versions for most years. This trend of lower projected emissions follows trends in actual U.S. power sector emissions, which have fallen over the past decade (Wiser et al. 2021).

4 Range of Outcomes across all Scenarios

In this section, we highlight the range of several key metrics across the full suite of scenarios. Because the Mid-case represents only one potential future, it is important to understand how the electric grid might evolve over a wide range of futures. Additionally, because sensitivities are performed based on the Mid-case, there is a natural clustering of projections around the Mid-case. This clustering should not be interpreted as indicating a higher likelihood.

Figure 4 shows the generation by fuel type across the full suite of scenarios. Natural gas, solar, and wind show the largest range in 2050 generation across the scenarios. Natural gas has an especially wide range in the No New Policy scenarios, with the largest deviations from the Mid-case coming from the natural gas price sensitivity scenarios. In scenarios with a national emissions limit, natural gas generation declines when the limit becomes more stringent but only goes to zero (by 2050) in the 95% by 2035 scenario that does not allow CCS technologies. Coal generation declines over time, though the rate of decline is strongly influenced by the CO_2 emission limit. Nuclear generation remains steady across most of the scenarios, with growth only coming in scenarios that assume low nuclear costs. Some scenarios see a slight decline in nuclear generation due to decreases in nuclear capacity factors in order to better integrate variable renewable resources.

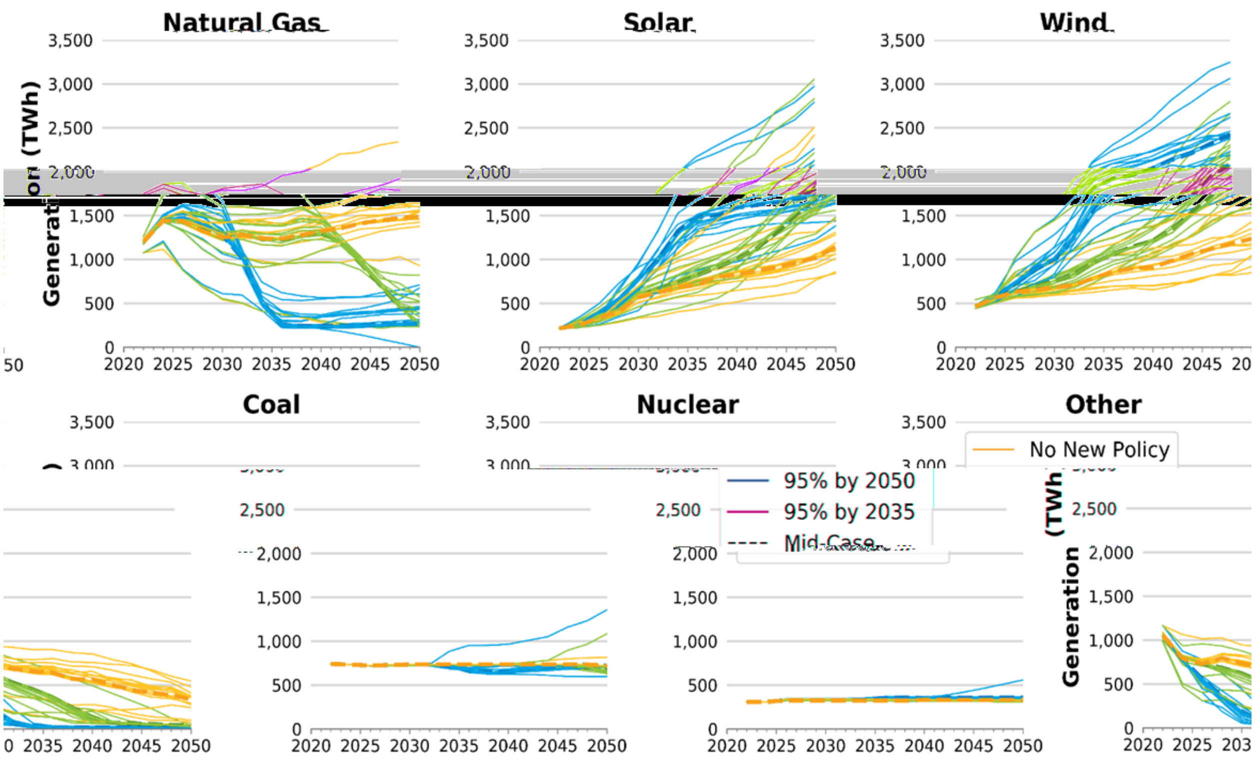


Figure 4. Generation by fuel type across the Standard Scenarios. The dashed line is the Mid-case scenario.

For capacity (see Figure 5), natural gas has a much narrower range than its generation range, and it grows across nearly all scenarios. That is largely because natural gas capacity is a high-value source of firm capacity, even in scenarios with limited natural gas generation. The low utilization rate of natural gas in the CO_2 emission reduction scenarios allows these generators to provide firm capacity while also limiting their emissions. Solar and wind have the widest range of 2050 deployment, and they are highly sensitive to the assumed technology costs, storage deployment, CO_2 emission reductions, and transmission availability. Solar reaches the highest overall capacity levels in part because it generally has a lower capacity factor than the other technologies while still having sufficiently low costs to be built in a least-cost framework. Growth in other renewable energy comes from biopower with CCS, geothermal, and modest new amounts of hydropower (see Appendix A.4). In the No CCS scenario, significant amounts of renewable energy combustion turbines (RE-CT) are deployed. These RE-CT generators are combustion turbines with a renewably derived fuel such as hydrogen, biodiesel, or green methane.

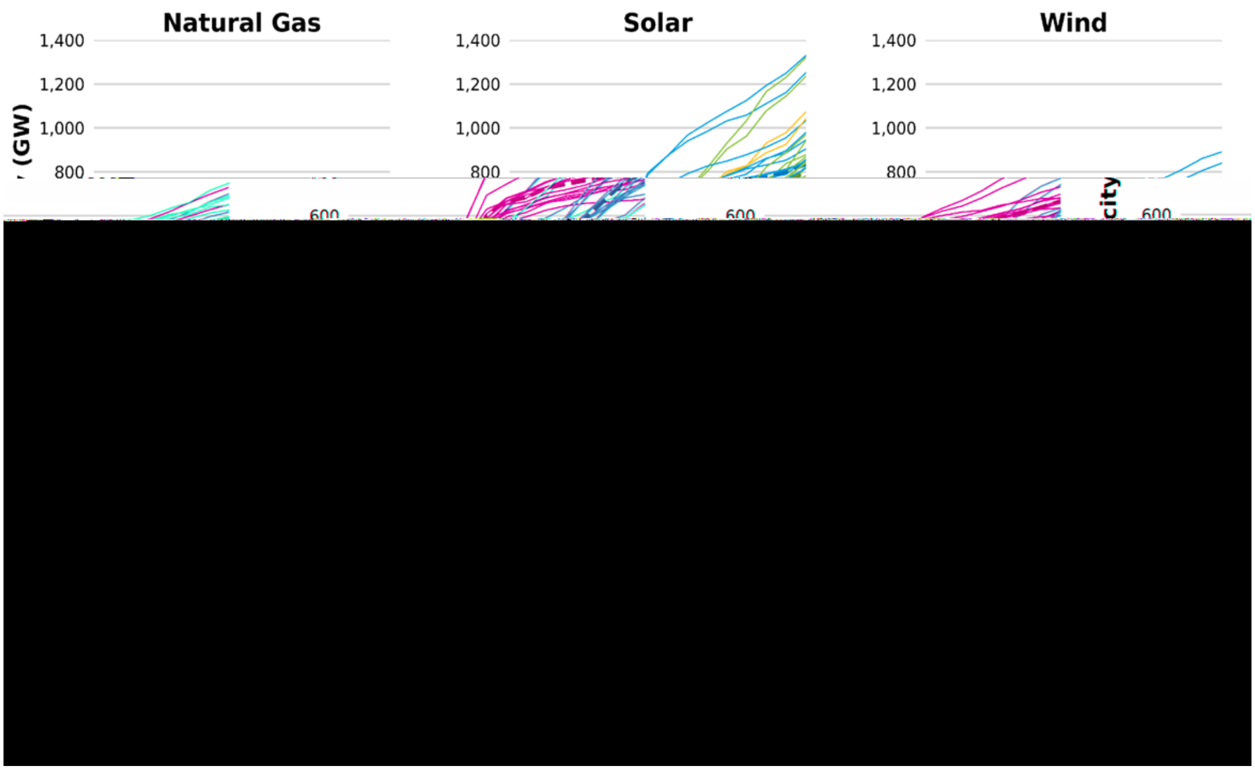


Figure 5. Capacity by fuel type across the Standard Scenarios. The dashed line is the Mid-case scenario. Note that some scenarios, especially in the "Nuclear" and "Other" plots, overlap with the Mid-case and are not visible. The natural gas line that goes to zero is the scenario that does not allow CCS. This scenario corresponds to the highest line on the "Other" plot, which is due to the build-out of renewable energy combustion turbines (RE-CT) in the No CCS scenario.

Storage also grows in all the scenarios, with the majority of growth coming from batteries. Figure 6 shows the average battery duration of the fleet. In all scenarios the duration starts near two hours and grows to a range of 4–6 hours by 2050 in most scenarios. Pumped storage hydropower capacity[18] also increases in most scenarios, with many scenarios doubling the amount of pumped storage hydropower capacity by 2050 (see Appendix A.4).

[18] New pumped storage hydropower capacity is assumed to have a duration of 10 hours.

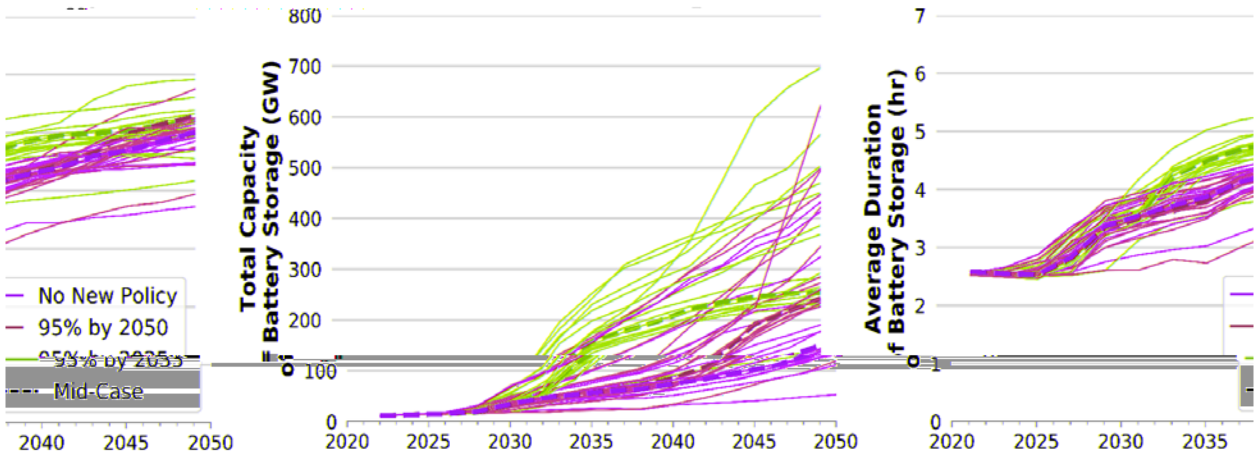


Figure 6. Total capacity (left) and average duration (right) of installed battery storage capacity across the Standard Scenarios. The dashed line is the Mid-case scenario. The highest line in the left plot corresponds to the No CCS scenario.

Total renewable energy share, defined as the fraction of total generation that is from renewable energy generators, grows from approximately 21% in 2020 to anywhere from 38% to over 80% in 2050 (see Figure 7). From the generation figures above (Figure 4), the increase in renewable energy penetration is primarily from wind and solar and is influenced heavily by the level of imposed emissions limits. Renewable energy shares do not climb much beyond 80% because the existing nuclear capacity is able to fill most of the remaining gap to meet the emission limits.

Figure 7. Renewable energy share over time across the Standard Scenarios. Renewable energy share is defined as annual renewable energy generation divided by total generation.

Figure 8 shows the transmission expansion across the scenarios. Higher levels of transmission development are correlated with both renewable energy deployment and higher natural gas prices. Higher renewable energy build outs can benefit from more transmission that can move power from regions with high concentrations of variable renewable energy to load centers where that otherwise-excess energy can be consumed. Higher natural gas prices create high energy prices, which can lead to greater price arbitrage opportunities between regions. The scenarios that include the high transmission costs result in more limited build-out of new transmission, but that build-out can still be significant when CO_2 reduction requirements are in place.

Figure 8. New long-distance transmission capacity over the Standard Scenarios. This reported capacity does not include the capacity of spur lines for connecting wind and solar plants to the transmission system. For reference, the scenarios start with 148 TW-mi in 2020.

Examples of the transmission buildout from the scenarios are in Figure 9. The High Transmission scenarios allow for a long-distance high-voltage direct current (HVDC) lines to be added. The model chooses to build many of those lines as part of the least-cost solution, with the total amount dependent on the level of CO_2 reductions (consistent with Figure 8). Scenarios with low transmission availability still expand the transmission system, but do so to a much lesser extent.

Figure 9. Total inter-regional transmission capacity in 2050 for the scenarios indicated. AC is alternating current and HVDC is high-voltage direct current.

Electricity sector CO_2 emissions are shown in Figure 10. Emissions decline in all scenarios, even those without an emission limit. Some scenarios have lower emissions than the requirement as a result of low technology costs, low natural gas prices, or the extension of renewable energy tax credits.

Figure 10. Power sector emissions over time across the Standard Scenarios. The highest and lowest emissions scenarios in 2050 are labeled, along with the low retirement scenario and the Low RE Cost scenario. The Mid-case scenario is the dashed line. MMT is million metric tonnes.

Carbon capture and sequestration technologies play a significant role in many scenarios for facilitating decarbonization for the last 5-10% of the power sector CO_2 emissions. The scenarios with CCS allow much of the existing fossil capacity to remain online, rather than requiring it to be retired and replaced. Figure 11 show the CCS deployment through 2050 across the suite of scenarios. CCS technologies available in the ReEDS model include natural gas with CCS, coal with CCS, biopower with CCS, and direct air capture. Table 3 shows the deployment amounts for those CCS technologies.

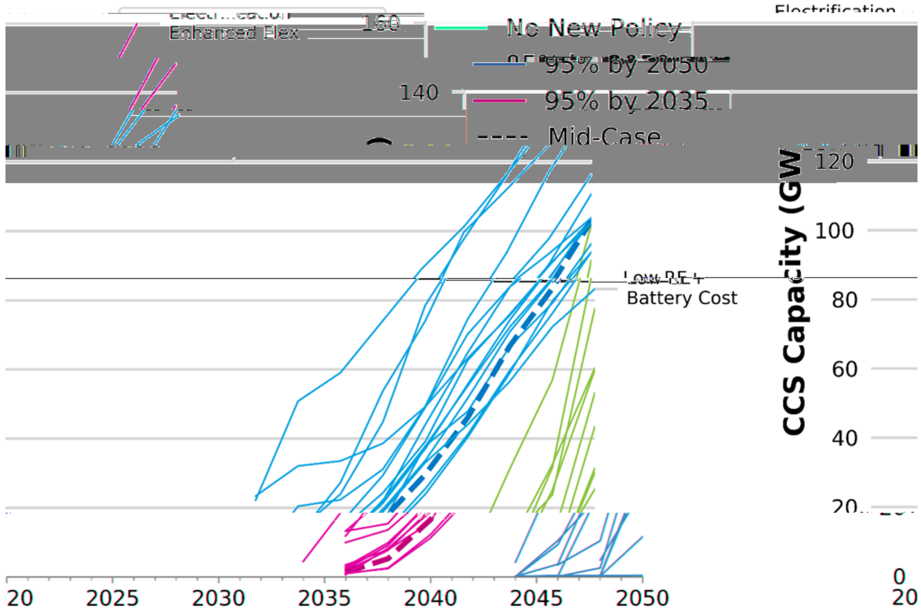


Figure 11. Deployment of CCS technologies across the Standard Scenarios.

Table 3. CCS capacity (in GW) deployed in 2050 in the scenarios with the specified CO_2 emissions reduction requirement. The No CCS scenarios are excluded from these ranges.

	No New Policy	95% by 2050	95% by 2035
NG-CC with CCS	0	6 – 96	1 – 64
Coal with CCS	0	0	0
Biopower with CCS	0 – 0.3	0.3 – 3.5	0.5 – 4.4
Direct air capture	0	0.1 – 42	60 – 141

Figure 12 shows the trends in the marginal costs[19] of the four major grid services in the ReEDS model. These model outputs, when coupled with information about the services that technologies can provide, are useful in understanding why the model makes certain decisions. The services are energy (ensuring there is enough energy in a time segment), planning reserve (ensuring there is enough capacity to meet the planning reserve requirement), operating reserve (ensuring there is

[19] These marginal costs are derived from the shadow prices on the constraints that represent these grid services. These marginal costs do not reflect the full costs of power system operation or investment. Rather they reflect only the bulk generation and transmission system investment and operational costs in a given model year. Costs of servicing existing debt, costs of distribution system upgrades, maintenance, and operation, and costs of any energy efficiency or demand response programs are not included.

enough capacity to deal with short-term contingencies and frequency regulation), and state policy provision[20] (providing generation to meet state generation constraints).

Figure 12. National annual average marginal costs for the services indicated across the Standard Scenarios. The dashed line shows the Mid-case for the three emission reduction trajectories. The marginal operating reserve cost is the sum of the three operating reserve products: regulation, spinning, and flexibility. The outlier in the top right plot is the No CCS scenario. Note that the units and scales are different in each plot.

Marginal energy costs are influenced by the CO_2 reduction requirement as well as factors such as natural gas prices and renewable energy technology costs. With no new policies, energy costs tend to be flat or declining in the long-term as natural gas prices remain fairly constant and zero-marginal-cost renewable energy shares increase.

Marginal planning reserve costs grow over time as planning reserve margins tighten relative to today's levels (by 2050, the ReEDS model has all regions exactly meeting the NERC recommended planning reserve levels). The especially high planning reserve costs in the 95% by 2035 CO_2 trajectory are the case where CCS technologies are not allowed, which leads to high

[20] The state policy costs shown reflect only the impact of renewable or clean electricity standards. State or regional emissions policies such as California's Assembly Bill 32 or the Regional Greenhouse Gas Initiative can indirectly impact all costs, especially marginal energy costs.

marginal costs for firm capacity; this is consistent with other work demonstrating the value of firm capacity at deep decarbonization levels (Sepulveda et al. 2018; Cole et al. 2021).

Marginal operating reserve costs generally fall over time across all scenarios, driven by an increase in storage deployment, but they can rise in the 95% by 2035 scenarios due to a rapid increase in the need for flexibility from increased deployment of variable renewable energy generators.

Marginal costs for state policies have mixed trends depending on the year and scenario, but they tend to follow the cost of building new renewable technologies (e.g., higher renewable energy cost scenarios result in higher costs to meet state policies), and the costs are lower with the CO_2 emissions limits in place because current state policies tend to incentivize zero-carbon technologies.

Figure 13 shows the losses from wind and solar curtailment, transmission, and storage. Curtailment is zero-marginal-cost electricity that cannot be used cost-effectively and therefore impacts only generators with zero marginal costs. Transmission and storage losses will impact any generator that is using those resources to move power across time or space. The storage and transmission losses are highest in the 95% by 2035 scenarios because they tend to have the most storage and transmission. Curtailment is highest in the 95% by 2050 scenarios, because low-utilization renewable energy generators make up a larger portion of the generation mix. At 100% decarbonization, additional low-utilization but high-flexibility resources are deployed, which lowers overall curtailment.

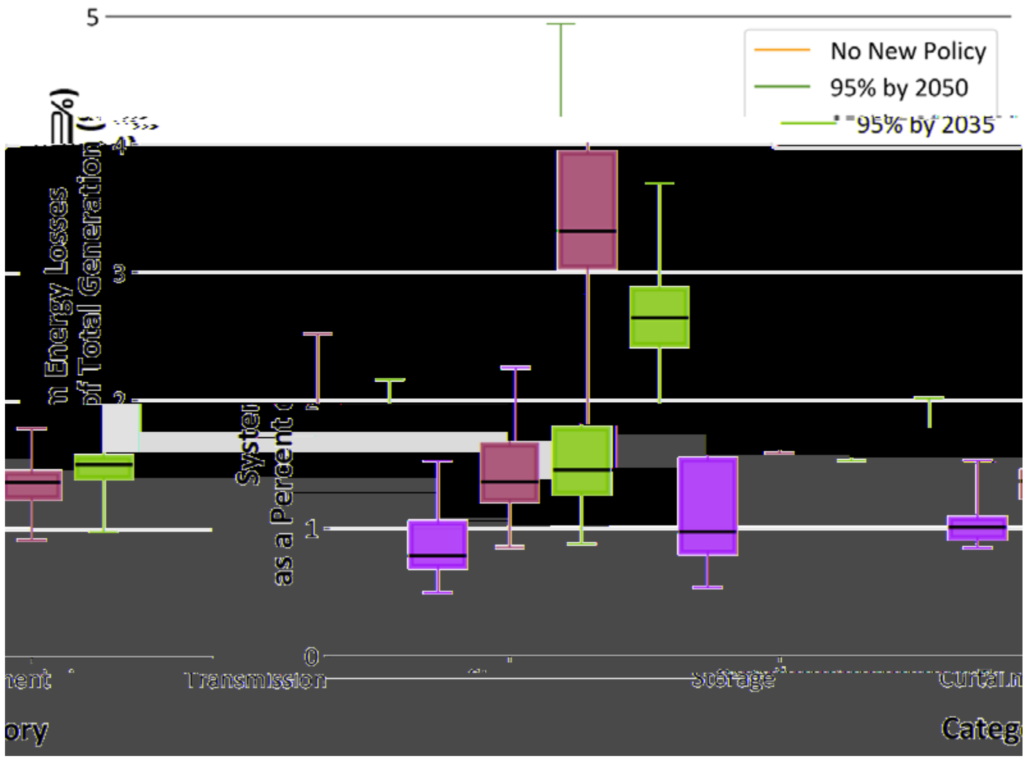


Figure 13. Storage, curtailment, and transmission (but not distribution) losses in 2050 as a percentage of total generation across scenarios using a box-and-whisker plot. The boxes show the 25th-75th percentile of scenario results, the black bar shows the median value, and the whiskers show the full range of results. For reference, the Mid-case scenario has 5,270 TWh of generation in 2050. The curtailment values translate to 1.3–6.4% of variable renewable energy generation.

Figure 14 shows the range in power system cost[21] across scenarios. Scenarios with the greatest system cost are those that include electrification, because the greater load growth in those scenarios leads to increased buildout of the electricity sector. That total increase in electricity system costs will be at least partially offset by savings in other sectors where the electrification occurs (for example, via reduced gasoline consumption in scenarios with more rapid adoption of electric vehicles). No nonelectric savings are reflected in the figure.

[21] Power system costs include capital costs for new transmission and generation capacity and operating costs for both existing and new transmission and generation capacity.

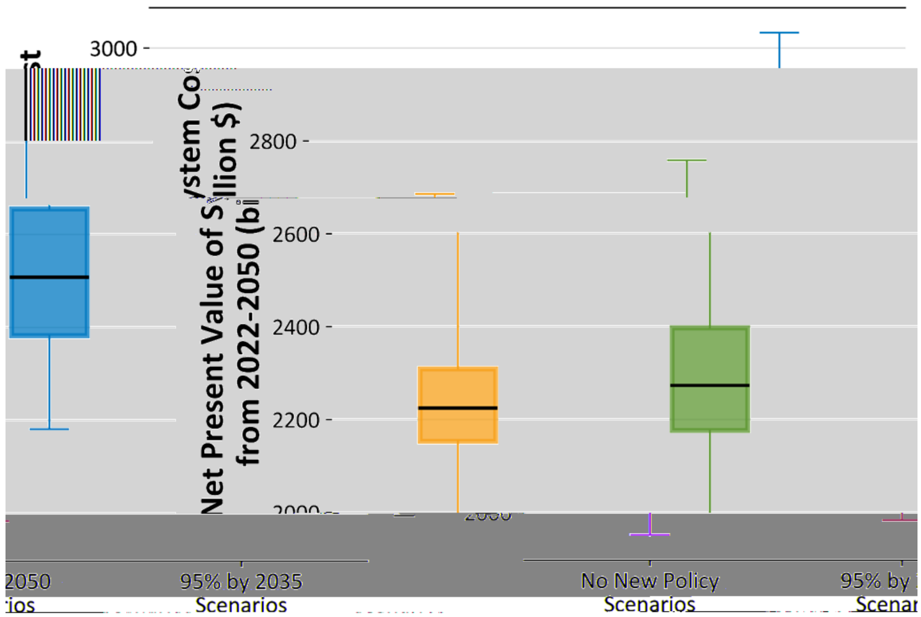


Figure 14. Net present value of system costs for the Standard Scenarios using a box-and-whiskers plot. The boxes show the 25th-75th percentile of results, the black bar is the median value, and the whiskers show the full range of results. System costs are the net present value (2020$) of the U.S. bulk power system from 2022 through 2050 using a 5% real discount rate. The Mid-case with No New Policy has a system cost of $2,225 billion dollars.

Two other ways to consider the cost of building out the electricity system are shown in Figure 15 and Figure 16. Figure 15 shows the marginal bulk power electricity cost, which is the $/MWh cost of supplying the four services from Figure 12. Figure 16 is the marginal CO_2 emissions cost, or the abatement cost of removing the next tonne of CO_2 from the system. The marginal CO_2 cost is effectively capped at the abatement cost of direct air capture, except in scenarios that do not allow CCS.

Figure 15. Marginal bulk power electricity cost over time across the Standard Scenarios. This bulk power cost does not include any distribution or administration costs, and it is calculated using the marginal costs from Figure 12.

Figure 16. Marginal CO_2 emissions cost from the carbon emission limit. This value is the shadow price from the CO_2 cap imposed in the model. The scenarios that go above $150/tonne are those that do not allow CCS technologies to be built.

5 Summary

The Standard Scenarios provide outputs for a wide range of scenarios for the electricity power sector using electricity sector models that attempt to address complex physical and economic factors. The scenarios provide a framework for assessing trends and a data set to help advance thinking of how the power sector might evolve over time. Within NREL, we have found significant value in using the Standard Scenario to accelerate analysis and provide a baseline for related work. We share them with the hope that they can be of similar value to other power-sector stakeholders as they make decisions that will influence the constantly changing electricity sector.

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Appendix

A.1 Standard Scenarios Input Assumptions

This section describes the high-level input assumptions used in the scenarios listed in Table A-1. For details about model assumptions, see the documentation for ReEDS (Ho et al. 2021) and dGen (Sigrin et al. 2016). Both models are publicly available (see www.nrel.gov/analysis/reeds/request-access.html and www.nrel.gov/analysis/dgen/model-access.html) and inputs are viewable within the model repositories. For ReEDS, the settings file used to create all the scenarios used in this report is included in the online repository, enabling the recreation of any of the scenarios.

Table A-1. Summary of the 2021 Standard Scenarios. The scenario settings listed in *blue italics* correspond to those used in the Mid-case scenarios.

Group	Scenario Setting	Notes
Electricity Demand Growth	*Reference Demand Growth*	*AEO2021 reference scenario growth rate*
	Low Demand Growth	AEO2021 low economic growth scenario
	High Demand Growth	AEO2021 high economic growth scenario
	High Electrification with Base Flexibility	High level of electrification and base demand-side flexibility based on the Electrification Futures Study (Mai et al. 2018; Sun et al. 2020)
	Reference Demand with Enhanced Flexibility	Enhanced demand-side flexibility based on the Electrification Futures Study (Mai et al. 2018; Sun et al. 2020)
	High Electrification with Enhanced Flexibility	High level of electrification and Enhanced demand-side flexibility based on the Electrification Futures Study (Mai et al. 2018; Sun et al. 2020)
Fuel Prices	*Reference Natural Gas Prices*	*AEO2021 reference*[a]
	Low Natural Gas Prices	AEO2021 high oil and gas resource and technology[a]
	High Natural Gas Prices	AEO2021 low oil and gas resource and technology[a]
Electricity Generation Technology Costs	*Mid Technology Cost*	*2021 Annual Technology Baseline (ATB) moderate projections*
	Low RE and Battery Cost	2021 ATB renewable energy advanced projections

Group	Scenario Setting	Notes
	High RE and Battery Cost	2021 ATB renewable energy conservative projections
	Low Nuclear and CCS Cost	2021 ATB advanced projection for coal and natural gas CCS technologies; 50% decline in small modular reactor technologies by 2030
	Low Technology Costs	2021 ATB advanced projection for RE and fossil CCS technologies; 50% cost decline in small modular reactor technologies by 2030
Resource and System Conditions	*Default Resource Constraints*	*See ReEDS documentation (Ho et al. 2021) for details.*
	Reduced RE Resource	Limited siting supply curves for wind and PV; 50% reduction to all other renewable energy resource supply curves
	Barriers to Transmission System Expansion	5x transmission capital cost; no new transmission builds between modeled transmission planning regions
	HVDC Transmission Allowed	HVDC transmission allowed in any model region
Policy/Regulatory Environment	*Current Law*	*Includes state, regional, and federal policies as of June 2021*
	95% by 2050	*95% reduction in power sector CO_2 emissions by 2050 (relative to 2005)*
	95% by 2035	*95% reduction in power sector CO_2 emissions by 2035 and 100% reduction by 2050 (relative to 2005)*
	Tax Credit Extension	Production and investment tax credits for renewable energy technologies extended at their full value by 10 years

[a] Natural gas prices are based on AEO2021 electricity sector natural gas prices but are not identical because of the application of natural gas price elasticities in the modeling. See the next section (Fuel Prices) for details.

Fuel Prices

Natural gas input price points are based on the trajectories from AEO2021 (EIA 2021). The reference, low, and high natural gas prices are shown in Figure A-1 (left) and are from the AEO2021 Reference scenario, the AEO2021 Low Oil and Gas Supply scenario, and the AEO2021 High Oil and Gas Supply scenario (EIA 2021), respectively. Actual natural gas prices in ReEDS are based on the AEO scenarios, but they are not exactly the same; instead, they are price-responsive to ReEDS natural gas demand. Each census region includes a natural gas supply curve that adjusts the natural gas input price based on both regional and national demand (Cole, Medlock III, and Jani 2016). Figure A-2 shows the output natural gas prices from the suite of scenarios.

The reference coal and uranium price trajectories are from the AEO2021 Reference scenario and are shown in Figure A-1 (right). Both coal and uranium prices are assumed to be fully inelastic. Figure A-1 shows the national prices for the resources, but coal input prices for ReEDS are taken from the AEO2021 census region projections (i.e., each census region has a different coal price).

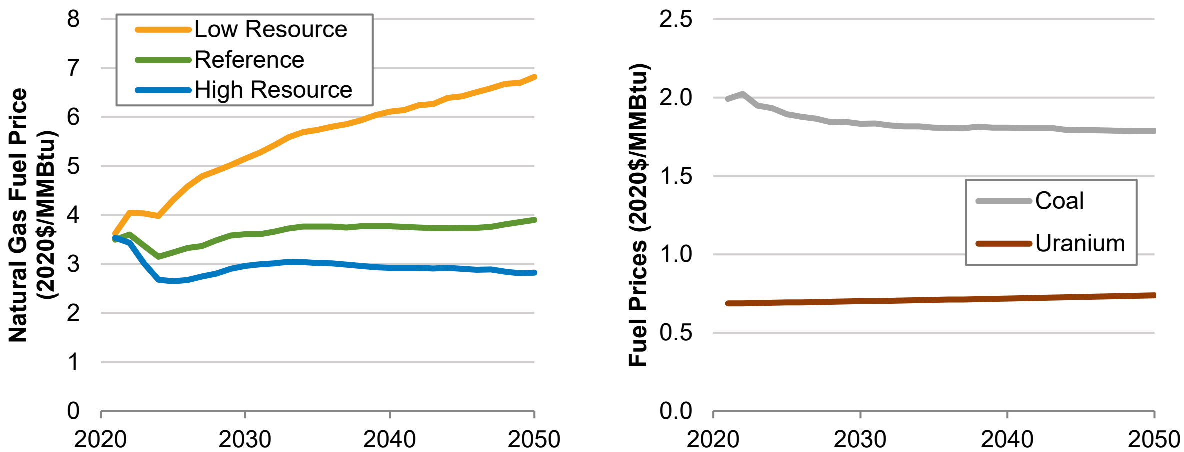

Figure A-1. Fuel price input trajectories used in the Standard Scenarios

Figure A-2. Natural gas price outputs from the suite of ReEDS scenarios.

Demand Growth and Flexibility

The Mid-case scenarios are based on the AEO2021 Reference scenario load growth (EIA 2021). The high- and low-load growth scenarios are also from AEO2021, based on the Low and High

Economic Growth scenarios, which use lower/higher rates of population growth, productivity, and lower/higher inflation than the Reference scenario (see Figure A-3). We assume inelastic electricity demand in all scenarios presented.

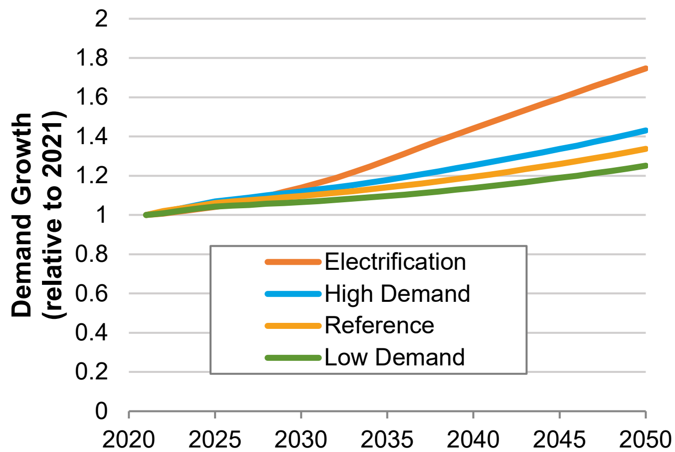

Figure A-3. Demand growth trajectories used in the Standard Scenarios.

The Electrification load growth projection is based on the Electrification Futures Study, or EFS (Mai et al. 2018), where future load growth is greater than in any of the AEO2021 scenarios because of an increase in fuel-switching from nonelectric to electric sources at the point of final consumption across all end-use sectors (i.e., residential and commercial buildings, transportation, and industry). Specifically, we use the EFS High Electrification with Moderate end-use technology advancement scenario (Jadun et al. 2017). In addition to greater annual load growth, end-use electrification in this scenario also changes load profiles, particularly in response to electric vehicle charging and electric space heating demands. ReEDS endogenously accounts for this demand-side flexibility, which is modeled as constrained load shifting, using the "Base" flexibility assumptions from the EFS (Sun et al. 2020). Under the electrification load growth assumption scenario, about 4% of annual load is assumed to be flexible. The source of this flexibility is primarily from managed electric vehicle charging, but flexibility from the buildings sector is also considered.

A higher level of demand-side flexibility is also considered for scenarios with reference demand levels and with electrification demand levels. These scenarios use the "Enhanced" flexibility assumptions from the EFS and allow 17% of annual demand to be flexible (Mai et al. 2018; Sun et al. 2020).

Technology Cost and Performance

Technology cost and performance assumptions are taken from the 2021 ATB (NREL 2021). The ATB includes advanced, moderate, and conservative cost and performance projections through 2050 for the generating and storage technologies used in the ReEDS and dGen models. The low RE and battery cost scenarios use the advanced projections for all renewable energy and battery technologies, and the high RE and battery cost scenarios use the conservative projections. Scenarios with low CCS costs use the advanced coal and natural gas CCS technology projections from the ATB.[22] Low nuclear costs are not available in the ATB, so to create a low nuclear cost projection we assume nuclear capital and fixed operations and maintenance costs for small modular reactor technologies decline to 50% below the moderate projections by 2030, and then continue a modest decline from 2030 through 2050 (see Figure A-4).

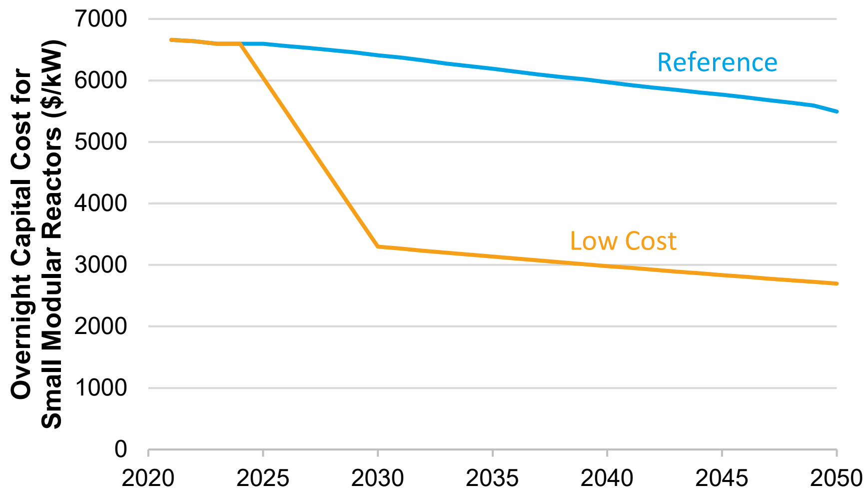

Figure A-4. Capital cost projections for small modular reactor technologies.

Direct air capture cost and performance values are taken from Fasihi, Efimova, and Breyer (2019) using the conservative assumptions. Biomass with CCS cost and performance values are from EPRI (2020). Renewable energy combustion turbines (RE-CT) are represented consistent with the Solar Futures Study (DOE 2021) and Cole et al. (2021). These RE-CT technologies have a renewably derived input fuel (such as hydrogen, biodiesel, ethanol, or green methane) that costs $20/MMBtu. They can be upgraded from natural gas turbines for 20% the cost of a new gas turbine, or built new at a cost 3% higher than natural gas turbines. Heat rates and operations and maintenance costs are the same as natural gas turbines. All RE-CT units are assumed to be clutched to allow them to also act as synchronous condensers.

Generator lifetimes are shown in Tables A-2 and A-3. These lifetimes represent that maximum lifetime a generator is allowed to remain online in the model. The model can choose to retire the generator before this lifetime if it deems that it is uneconomic to leave the generator online.

[22] Existing coal plants are allowed to add CCS by paying the difference in cost between a new coal plant with and without CCS.

Table A-2. Lifetimes of Renewable Energy Generators and Batteries

Technology	Lifetime (Years)	Source
Land-based wind	30	Wind Vision (DOE 2015)
Offshore wind	30	Wind Vision (DOE 2015)
Solar PV	30	SunShot Vision (DOE 2012)
Concentrating Solar Power	30	SunShot Vision (DOE 2012)
Geothermal	30	GeoVision Study (DOE 2019)
Hydropower	100	Hydropower Vision (DOE 2016)
Biopower	50	2021 National Energy Modeling System plant database (EIA 2021)
Marine hydrokinetic	20	Previsic et al. (2012)
Battery	15	Cole, Frazier, and Augustine (2021)

Table A-3. Lifetimes of Nonrenewable Energy Generators

Technology	Lifetime for Units Less than 100 MW (Years)	Lifetime for Units Greater than or Equal to 100 MW (Years)
Natural gas combustion turbine	50	50
Natural gas combined cycle and CCS	60	60
Coal, all technologies, including cofired	65	75
Oil-gas-steam (OGS)	50	75
Nuclear	80	80

Reduced Renewable Energy Resource and Restricted Siting

This scenario reduces the amount of renewable energy resource that could be developed in ReEDS. For land-based wind, additional setbacks and land exclusions are applied that reduce the amount of resource available to 2.03 TW, compared with 6.64 TW in the default case. The reductions vary by region and are largely based on the methods and assumptions from Lopez et al. (2021), but updated to consider the impacts of shadow flicker. A similar method is applied for offshore wind, where the deployable resource is reduced from 4.27 TW in the default cases to 2.12 TW with more stringent siting constraints. These reductions stem primarily from lower capacity density to accommodate fishing and shipping industries through required 1-nuatical mile spacing of turbines, and greater setbacks from shore as a proxy for coastal viewshed concerns. Similar but coarser resource representation for PV results in a reduced resource potential scenario of 35.42 TW compared with 95.9 TW in the default case. For other renewable energy technologies (CSP, geothermal, hydropower, and biopower) technical potential is reduced by 50%. The reduction is applied uniformly across geography and resource classes (i.e., all regions and classes experience the same 50% reduction).

Barriers to Transmission System Expansion

The ReEDS model assumes new transmission lines can be constructed as needed, at costs taken from the Eastern Interconnection Planning Collaborative (EIPC 2012) on regional transmission development and extrapolated to the contiguous United States (DOE 2015). Those cost assumptions include regional multipliers that imply higher siting and construction costs in certain areas, notably California and the Northeast. This scenario assumes that transmission will not be built between transmission regions (e.g., PJM and the Midwest ISO will not build lines between their regions). It also assumes that transmission costs are 5 times higher than the default ReEDS assumptions. This 5x increase represents more challenges in siting new transmission lines as well as the cost of undergrounding substantial portion of new lines.

Transmission Expansion

All scenarios except for the high and low transmission scenarios allow for the current transmission network to be expanded. Only existing corridors can be expanded.

The high transmission scenario allows for new high voltage direct current (HVDC) transmission lines to be built anywhere in the country. The HVDC systems have a per mile loss rate that is 1/3 that of AC systems, but also have converters that incur losses when power is converted from between DC and AC.

The low transmission scenario does not allow transmission builds between RTO/ISO regions (e.g., new lines between PJM and MISO are not allowed). This scenario also increases transmission costs by 5x, reflecting the cost of undergrounding substantial portions of new transmission lines.

A.2 Changes from the 2020 Edition

Since last year's Standard Scenarios report (Cole, Corcoran, et al. 2020), we have made the key modeling changes in the ReEDS model that are summarized in Table A-4. The dGen scenarios used in the report are identical to those used for the 2020 report. Also, this year's report has an updated scenario structure, with a reduced set of sensitivities performed on the Mid-case scenario but using a range of CO_2 emission limits (in prior editions, there was a more comprehensive set of sensitivities was performed using from the No New Policy Mid-case). The total number of scenarios is approximately the same, but the number of unique sensitivities has been reduced. Specific assumptions for these scenarios are documented in Section A.1.

Table A-4. Key Differences in Model Inputs and Treatments for ReEDS Model Versions. The 2020 version (Ho et al. 2021) was used in the 2020 Standard Scenarios report (Cole, Corcoran, et al. 2020), and the 2021 version is used for this report.

Inputs and Treatments	2020 Version (July 2020)	2021 Version (July 2021)
Fuel prices	AEO2020	AEO2021
Demand growth	AEO2020	AEO2021
Generator technology cost, performance, and financing	2020 ATB[a]	2021 ATB[a]

Inputs and Treatments	2020 Version (July 2020)	2021 Version (July 2021)
Generator plant database	AEO2020	AEO2021
Renewable fuel combustion turbine	Includes combustion turbine that runs on a generic renewable fuel	Allows combustion turbines to operate on a generic renewable fuel or endogenously produced hydrogen
Hydrogen production technologies[b]	Not included	Steam methane reforming, with and without CCS, and electrolyzers are included
Hydrogen transport and storage cost[b]	Not included	Single, user-specified $/tonne cost applied to all hydrogen produced (default value: $300/tonne)
Carbon dioxide removal technologies	Not included	Biopower with CCS and direct air captured included with negative emissions factors
CO_2 transport and storage cost	Not included	Single, user-specified $/tonne cost applied to captured CO_2 (default value: $15/tonne)
Biomass supply curve	Based on 2011 Billion-Ton Update report; includes all biomass resource types	Based on the 2016 Billion-Ton report; includes only woody biomass resources
Biomass collection and transport cost	Not included	Single, user-specified $/dry ton cost applied to all biomass consumed in the power sector (default value: $30/dry ton)
Land-based wind supply curve	Spatially-explicit modeling of multiple exclusions and setbacks from buildings, roads, transmission rights-of-way, and radar along with other exclusion layers (Lopez et al. 2021)	Updated to include impacts of shadow flicker.
Offshore wind supply curve	Technical potential estimates produced capturing competing uses and environmentally sensitive areas (Musial et al. 2016)	Spatially-explicit modeling of existing underwater infrastructure (oil & gas wells/platforms, marine cables, etc.), competing uses (military exclusions, shipping lanes, fishing, etc.), and environmentally sensitive areas (marine protected areas, etc.)
PV supply curve	Technical potential estimates produced using National Land Cover Data as basis for excluding urbanized areas, roads, and other built infrastructure, exclusions of protected lands, and slope restrictions (Lopez et al. 2012)	Updated to capture USDA identified “prime” and “important” farmlands, and to exclude federal lands and forests, and resources in remote areas that are very distant from transmission access

Inputs and Treatments	2020 Version (July 2020)	2021 Version (July 2021)
Retail Rate Accounting	Not included	Investor-owned utility cost accounting applied to calculate retail rates in future years
Spinning reserve cost	No cost for providing spinning reserves	Spinning reserve cost equal to the heat rate reduction from operating at part load
Storage operating reserve provision	Storage can provide operating reserves when empty; storage never incurs losses for providing operating reserves	Storage must have energy to meet operating reserve requirements; storage incurs losses for providing regulation reserves
Nuclear small modular reactor technology	Not included	Included as an investment option, based on AEO2021 projections
Flexibility of existing nuclear plants	Existing nuclear plants are not allowed to turn down	Existing nuclear plants can turn down to 70% of their maximum capacity
Lifetime of nuclear plants	Default of 60 years for plants in restructured markets, 80 years for plants in traditional regulated regions	Default of 80 years for all nuclear plants that have not already announced a retirement date
Pumped-storage hydropower capital cost	DOE Hydropower Vision (DOE 2016) using 30-year history of Federal Energy Regulatory Commission licenses and preliminary permits	Bottom-up geospatial site identification and cost model with consistent and complete nationwide coverage
Hydropower flexibility and upgrades	Existing fleet classified by dispatchability and generic capacity+energy upgrade potential	Optional features to allow independent capacity or energy upgrades, add pumps, or convert to dispatchable; optional feature to enable seasonal shifting of hydropower energy and pumped-storage hydropower energy arbitrage
PV+battery hybrid technology	Not included	Included with an inverter loading ratio of 1.3 and a 4-hour battery sized at half of the PV inverter capacity
High-voltage DC transmission	Single static HVDC overlay option	Fully endogenous HVDC representation, with both voltage source converter and line commutated converter technologies represented; line costs and losses are specific to HVDC systems
Transmission fixed operations and maintenance costs	Not included	Annual fixed operations and maintenance costs set to 1.5% of the base transmission capital costs

Inputs and Treatments	2020 Version (July 2020)	2021 Version (July 2021)
Near-term transmission builds	Updated in 2012 to include proposed and under construction lines	Updated in 2020 to include proposed and under construction lines
Curtailment reduction from new transmission	New transmission built to a neighboring region can reduce curtailment in the exporting region	New transmission built to any region could reduce curtailment in the exporting region
Step size for variable renewable energy (VRE) calculations	Model uses a 1000 MW step size when calculating marginal VRE curtailment and capacity credit	Model sets the step size based on the amount of VRE capacity built in the previous year when calculating marginal VRE curtailment and capacity credit
Minimum capacity factor for thermal plants	Natural gas combustion turbines had a minimum of 1% annually	All thermal plants have a minimum of 6% annually
Tax credits	Use a four-year safe harbor construction period; December 2019 production tax credit update represented; tax credits for CCS represented (use of captured carbon is not considered)	December 2020 tax credit update represented
State policies	Policies as of June 2020	Policies as of June 2021
California power sector carbon cap	Carbon cap set at the levels projected by the California Public Utilities Commission in 2018 (42 million tonnes in 2030)	Carbon cap set at the levels projected in the 2019-2020 integrated resource plan (16 million tonnes in 2045)
Revised Cross-State Air Pollution Rule Update	Uses 2016 ozone season nitrogen oxides (NOx) emission limits	Uses 2021 ozone season NO_x emission budgets
Flexible temporal resolution	Hourly chronological data used for storage and VRE calculations; static 17-timeslice representation used in investment optimization	Hourly chronological data used for storage and VRE calculations; user-specified time-slices used in investment optimization

[a] The default cost recovery period in ReEDS is 20 years, while it is 30 years in the ATB.
[b] Although hydrogen production is endogenously represented in the 2021 model version, this capability is not turned on by default for the scenarios presented in this report.

A.3 Model Interactions

The Standard Scenarios use three different models (dGen, ReEDS, and PLEXOS) to produce the suite of outputs reported here and included in the Standard Scenarios Results Viewer. dGen produces projections for rooftop PV deployment over time using marginal electricity costs from ReEDS.[23] The dGen projections for rooftop PV are used as exogenous inputs in the ReEDS model. ReEDS then projects the grid evolution through 2050, resulting in most of the outputs that are reported here. For a select set of scenarios, the systems produced by ReEDS are converted to PLEXOS databases (Frew et al. 2019) and run through PLEXOS. PLEXOS applies a mixed-integer programming technique to solve an hourly unit commitment and dispatch problem for each of the ReEDS-produced systems.

For the scenarios run in PLEXOS, the Cambium team calculates a variety of emission, cost, and operational metrics for each region and year. Users of the data should be aware of some important considerations as they use the data:

- For the scenarios that use a carbon cap (the 95% by 2050 and 95% by 2035 scenarios), the long-run marginal emissions rate for years where the cap is binding would be zero. However, this result would only manifest in the specific situation of a grid-wide, mass-based carbon policy. In order to make these metrics more useful to users who are interested in emission rates in decarbonized futures, we represent the carbon policy in a slightly different form when performing the modeling used to derive the Cambium databases. Specifically, in ReEDS, we calculate an equivalent emissions rate limit instead of an absolute limit, and for each PLEXOS model run we take the shadow price from that carbon constraint and apply it as a cost adder to any generators with CO_2 emissions from direct combustion. The metrics in the Cambium database for the decarbonization scenarios are therefore closer to the values that might be seen under a policy that drives decarbonization through means other than an absolute mass-based cap (such as using incentives or penalties). Ultimately, the emission rate in a future in which policy is the primary driver of decarbonization will depend on both the generation mix and on the policy design.
- The data published for the Standard Scenarios come from the ReEDS and PLEXOS models, which are system-wide least-cost optimization models. In some instances, this can result in rapid shifts in the solutions (e.g., changing technology costs can result in a region building predominately solar capacity in one year and predominately wind capacity in the following year). While these shifts capture important trends, they can appear to be misleadingly precise because 1) often the changes happen more rapidly in the models than might be expected in practice and 2) the inputs into the models are generally not accurate enough to predict exactly which year such a shift might happen. Because of this, the long-run marginal emission rate is also provided as a rolling average of three solve years (e.g., 2030's values are an average of 2028, 2030, and 2032). For other analyses that depend on occurrences in specific years, we encourage users to take similar approaches that mitigate potential inaccuracies that could arise from the implied precision of the data. For example, if a user is interested in the new capacity that is installed in a specific year, they might be better served by looking at the new capacity that is installed in a general timeframe instead of a single year. The scenarios and tools used are all deterministic and therefore do not implicitly capture uncertainties about the

[23] The reason that not all scenarios are uniquely modeled in dGen is that many of the marginal electricity costs from the ReEDS scenarios are similar, so the resulting dGen projections would also be similar.

future. We partially address this by including many scenarios and recommend that users also consider multiple scenarios as they conduct their own analyses.

A.4 Additional Deployment Results

The “Other RE” category from Figure 5 includes hydropower, biopower, and geothermal, and the storage category in Figure 5 includes both pumped storage hydropower and batteries. Figure A-5 details the deployment results for these technologies.

Figure A-5. Capacity by fuel type for the other RE technologies across the Standard Scenarios. The dashed line is the Mid-case scenario. Note that the scale is different in the charts. Biopower capacity includes capacity fitted with CCS.

Figure A-6 shows the annual average deployment rate by technology for the technologies indicated across the full range of scenarios. The deployment rate includes both new builds and refurbishments of capacity that has reached its specified lifetime.

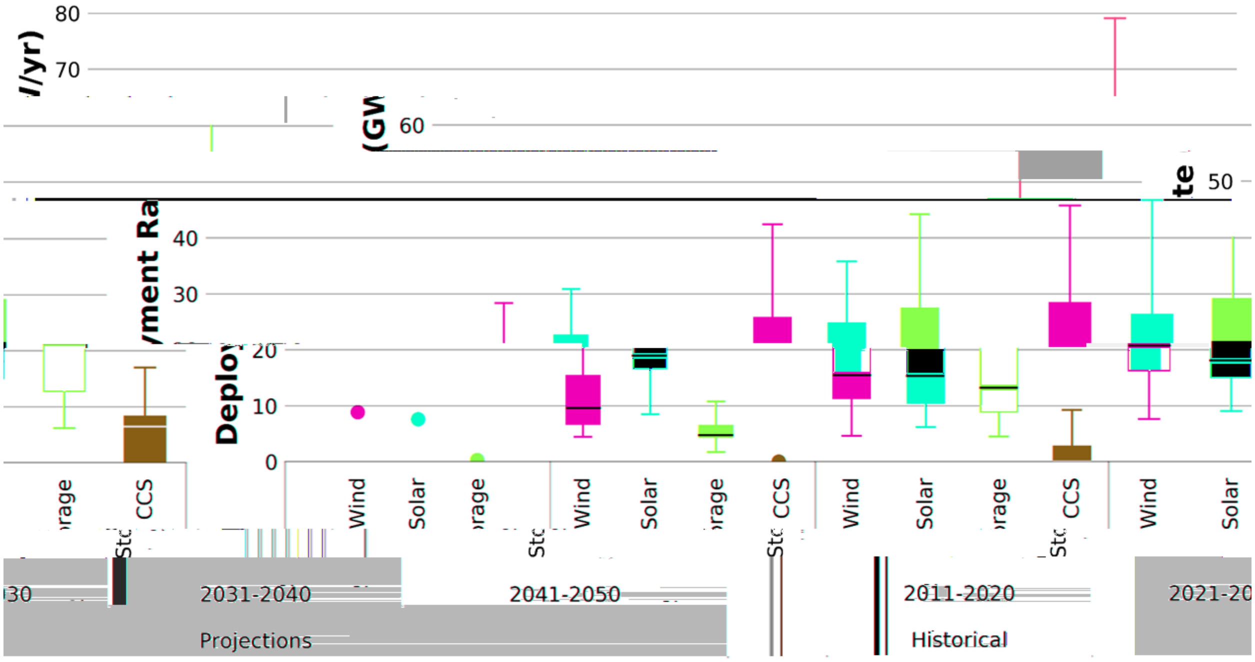

Figure A-6. Average deployment rates by decade for the technologies indicated. CCS includes natural gas, coal, and biopower with CCS, along with direct air capture.

Figure A-7. State-level generation mix for 2020 (top left) and for the Mid-case scenario under the three CO_2 limits.