2022 Standard Scenarios Report: A U.S. Electricity Sector Outlook

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Contributing Authors: Sarah Awara, Vincent Carag, Stuart Cohen, Wesley Cole, Jonathan Ho, Sarah Inskeep, Nate Lee, Trieu Mai, Matthew Mowers, Caitlin Murphy, and Brian Sergi

National Renewable Energy Laboratory

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Preface

This report is one of a suite of National Renewable Energy Laboratory (NREL) products aiming to support forward-looking electricity sector analyses and decision-making. The objective of the effort in this report is to identify a range of possible futures for the U.S. electricity sector while seeking to illuminate specific energy system issues and discussing future trends in outcomes such as energy technology deployment and production, energy costs, and emissions.

This effort is supported by the U.S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy (EERE). It 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 various generation technologies
- An ATB summary website describing each of the technologies and providing additional context for their treatment in the workbook
- This Standard Scenarios scenario framework, report, and data set describing U.S. electricity sector futures
- The Cambium data sets, which contain a broader suite of metrics for a subset of scenarios from this report.

These products can be accessed at atb.nrel.gov, www.nrel.gov/analysis/standard-scenarios.html, and www.nrel.gov/analysis/cambium.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 electricity sector futures
- An enhanced framework for formulating and addressing new analysis questions.

This report documents the eighth edition of the annual Standard Scenarios. Most of this year's scenarios include representations of the main electricity sector provisions from the Inflation Reduction Act of 2022 (IRA). Forthcoming studies include a more detailed analysis of the impacts of IRA on the U.S. electric sector. Future analyses are expected to build on the assumptions used here and provide increasingly sophisticated views of the future U.S. electric sector and its interactions with other sectors of the U.S. energy economy.

Acknowledgments

We gratefully acknowledge the many people whose efforts contributed to this report. We thank Mike Meshek for editing this work. We are grateful to comments from Adria Brooks, Bethany Frew, Patrick Gilman, Zachary Goff-Eldredge, Carl Mas, Gian Porro, Mark Ruth, Paul Spitsen, Dean William, and Ryan Wiser. 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.

Errata

This report, originally published in December 2022, has been revised in March 2023 to address an erroneous description in appendix section A.4 of several of the CO_2 emissions metrics that are available for download. The original report described the CO_2 metrics as only including emissions from generators, and has been corrected to indicate that the metrics also include the effects of CO_2 capture from direct air capture technologies in the five sensitivities that include direct air capture technologies. This correction does not affect the other 65 scenarios, as those scenarios do not contain direct air capture technologies.

List of Acronyms

AC	alternating current
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BNEF	BloombergNEF
CARB	California Air Resources Board
CC	combined cycle
CCS	carbon capture and storage
CO_2	carbon dioxide
CSP	concentrating solar power
CT	combustion turbine
DC	direct current
dGen	Distributed Generation Market Demand Model
DOE	U.S. Department of Energy
EERE	Office of Energy Efficiency and Renewable Energy (DOE)
EIA	U.S. Energy Information Administration
EPA	United States Environmental Protection Agency
HVDC	high-voltage direct current
IEA	International Energy Agency
IRA	Inflation Reduction Act of 2022
ITC	investment tax credit
MMBtu	million British thermal units
MMT	million metric tons
MW	megawatt
MWh	megawatt-hour
NETL	National Energy Technology Laboratory
NG	natural gas
NG-CC	natural gas combined cycle
NG-CT	natural gas combustion turbine
NOx	nitrogen oxides
NREL	National Renewable Energy Laboratory
OGS	oil-gas-steam
PTC	production tax credit
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
USLCI	U.S. Life Cycle Inventory Database
VSC	voltage source converter

Executive Summary

This report documents the eighth edition of the annual Standard Scenarios. It summarizes 70 forward-looking scenarios of the U.S. electricity sector that have been designed to capture a wide range of possible futures.

In August 2022, the United States Congress passed the Inflation Reduction Act (IRA), a law aimed at accelerating U.S. decarbonization, clean energy manufacturing, and deployment of new power and end-use technologies. This year's scenarios include representations of the main electricity-sector provisions from IRA and the potential impact on electricity demand.[1]

The Standard Scenarios are simulated using the Regional Energy Deployment System (ReEDS) model, which projects utility-scale electricity sector evolution for the contiguous United States using a system-wide, least-cost approach subject to policy and operational constraints. A subset of the scenarios are simulated in the PLEXOS production cost model to obtain a broader suite of metrics at the hourly resolution, which are made available through the National Renewable Energy Laboratory's (NREL's) annual Cambium data sets.

The scenarios can be viewed and downloaded from NREL's Scenario Viewer. Annual results are available for the full suite of scenarios in the *Standard Scenarios* projects in the viewer, whereas the *Cambium* projects contain hourly data for a subset of scenarios.

The Standard Scenarios includes a scenario called the Mid-case, which has central or median values for core inputs such as technology costs and fuel prices, moderately paced demand growth averaging 1.3% per year, and electricity sector policies as they existed in September 2022 (including IRA). The remaining 69 scenarios are created by varying inputs such as technology and fuel prices, resource availability, demand growth, whether nascent generation technologies are allowed, and by introducing national decarbonization constraints.

We highlight four observations from this year's projections:

1. **Wind and solar grow significantly, making up the majority of new generation:** By 2050 wind and solar generation reach 1500 TWh/year and 1600 TWh/year (a 3.5x and 7x increase over current levels respectively) in the Mid-case. Across all the scenarios that include IRA, their generation ranges from 1400-3000 TWh/year for wind and 1300-3100 TWh/year for solar.
2. **Still-nascent technologies can play a role:** Retrofits of natural gas and coal plants with carbon capture and storage (CCS) technologies often occur, with contributions peaking at 230 TWh/year and 100 TWh/year respectively in the Mid-case. Biopower with CCS, electricity-powered direct air capture, and renewable fuel combustion turbines are only deployed in scenarios where national decarbonization constraints are imposed.

[1] IRA is large and complex. Our representation does not include all provisions that may influence the electricity sector, and the provisions that are represented are generally simplifications. See Section 2.3 for details.

3. **U.S. electricity sector emissions decrease significantly through the 2030s:** Compared to 2021 emissions, annual U.S. national electricity-sector CO_2 emissions in 2035 are reduced by 77% in the Mid-case and 46%-87% across all scenarios with current policies (including IRA).
4. **A phaseout of IRA's tax credits may result in emissions rebounding in later years:** IRA's tax credits are either scheduled to phase out at the end of 2032 or when an emissions threshold is met, depending on the credit. In scenarios where the emissions threshold is met, the corresponding phaseout of the PTC and ITC can reverse several trends. For example, in the Mid-case the lowest annual CO_2 emissions of 300 MMT/year is seen in 2038, but the phaseout of tax credits results in a later-year rebound to 750 MMT/year by 2050. These reversals are not seen in scenarios where the PTC and ITC do not expire, or where decarbonization trajectories are imposed.

To illustrate some of these trends, we show the generation and capacity trends for five scenarios below. One scenario is the Mid-case mentioned previously, and the other four share the same core assumptions as the Mid-case but with national electricity sector decarbonization constraints and/or the exclusion of nascent technologies:

1. **The Mid-case:** central estimates for inputs such as technology costs, fuel prices, and demand growth, with electricity sector policies as they existed in September 2022
2. **The Mid-case with 95% Decarbonization by 2050:** the same set of core assumption as the Mid-case but with a national electricity sector decarbonization constraint that linearly declines to 5% of 2005 emissions on net by 2050
3. **The Mid-case with 100% Decarbonization by 2035:** the same set of core assumption as the Mid-case but with a national electricity sector decarbonization constraint that linearly declines to zero net emissions by 2035
4. **The Mid-case without Nascent Technologies:**[2] the same set of core assumptions as the Mid-case but where nascent electricity sector technologies are not included
5. **The Mid-case with 95% Decarbonization by 2050 without Nascent Technologies:** a case equivalent to the Mid-case with 95% decarbonization by 2050 scenario but where nascent electricity sector technologies are not included.

[2] Nascent technologies are defined here as enhanced geothermal systems, floating offshore wind, coal CCS, natural gas CCS, biopower CCS, small modular nuclear reactors, and renewable fuel combustion turbines. See Section 2.2 for a list of established technologies.

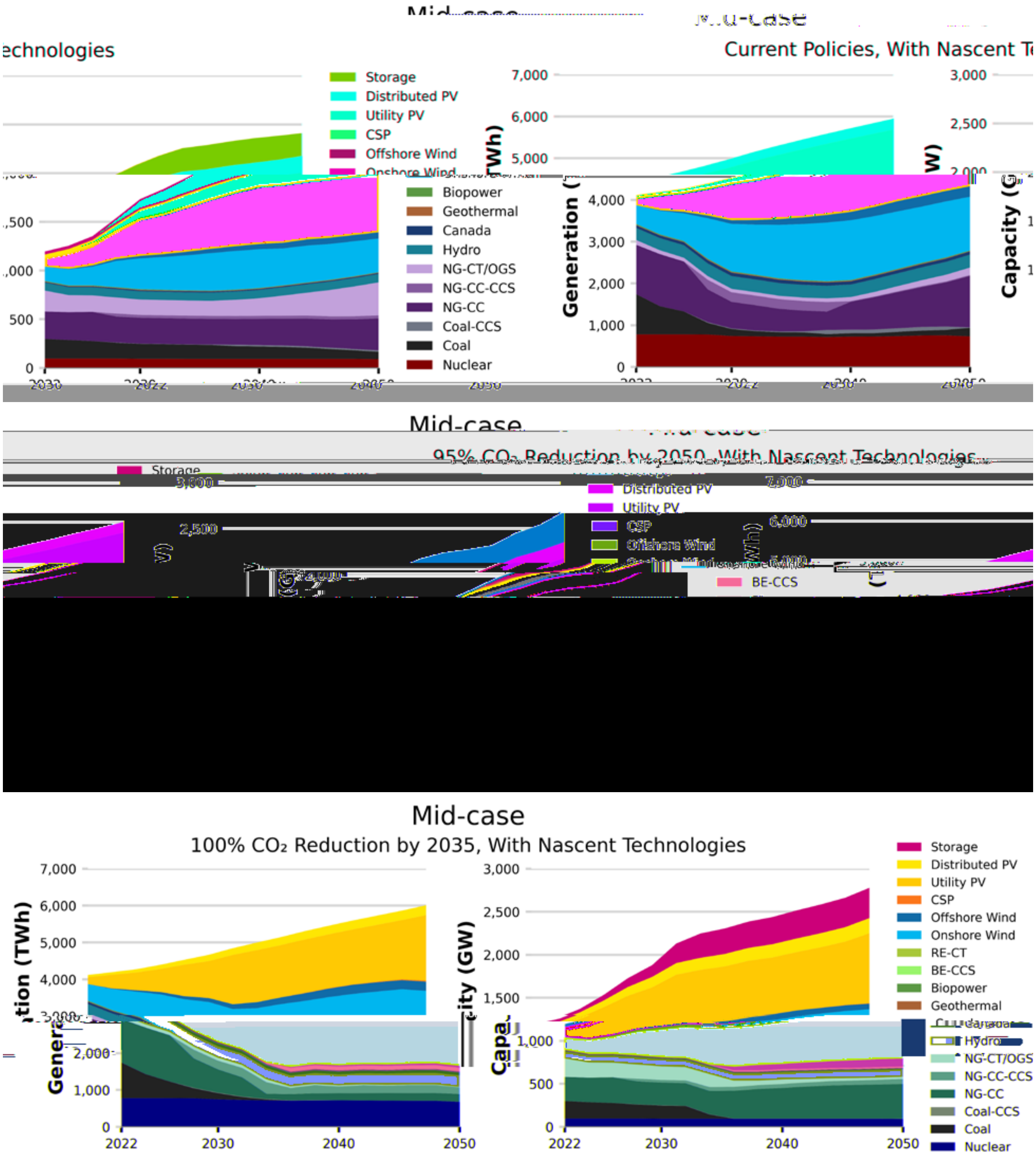

Figure ES-1. U.S. electricity sector generation (left) and capacity (right) over time for the three Mid-case scenarios with both established and nascent generation technologies. NG-CC is natural gas combined cycle, NG-CT is natural gas combustion turbine, OGS is oil-gas-steam, RE-CT is renewable fuel combustion turbine, BE is bioenergy, Canada is imported energy from Canada, CSP is concentrating solar power, and CCS is carbon capture and storage.

The three panels in Figure ES-1 (above) show the versions of the Mid-case with the most expansive set of generation technologies, which includes technologies that are still nascent as well as those more established. The two panels in Figure ES-2 (below) show the versions of the Mid-case with a more conservative set of generation technologies, where still-nascent technologies are excluded.

Note that the 100% by 2035 emission trajectory is not combined with the No Nascent Technologies set, because such a scenario requires more careful treatment than was feasible in this year's Standard Scenarios (for example, in examining and interpreting the exceptionally rapid generator buildouts). For readers interested in a more detailed exploration of zero-carbon systems under a 2035 timeframe, we direct them to NREL's [100% Clean Electricity by 2035 Study](#) (Denholm et al. 2022).

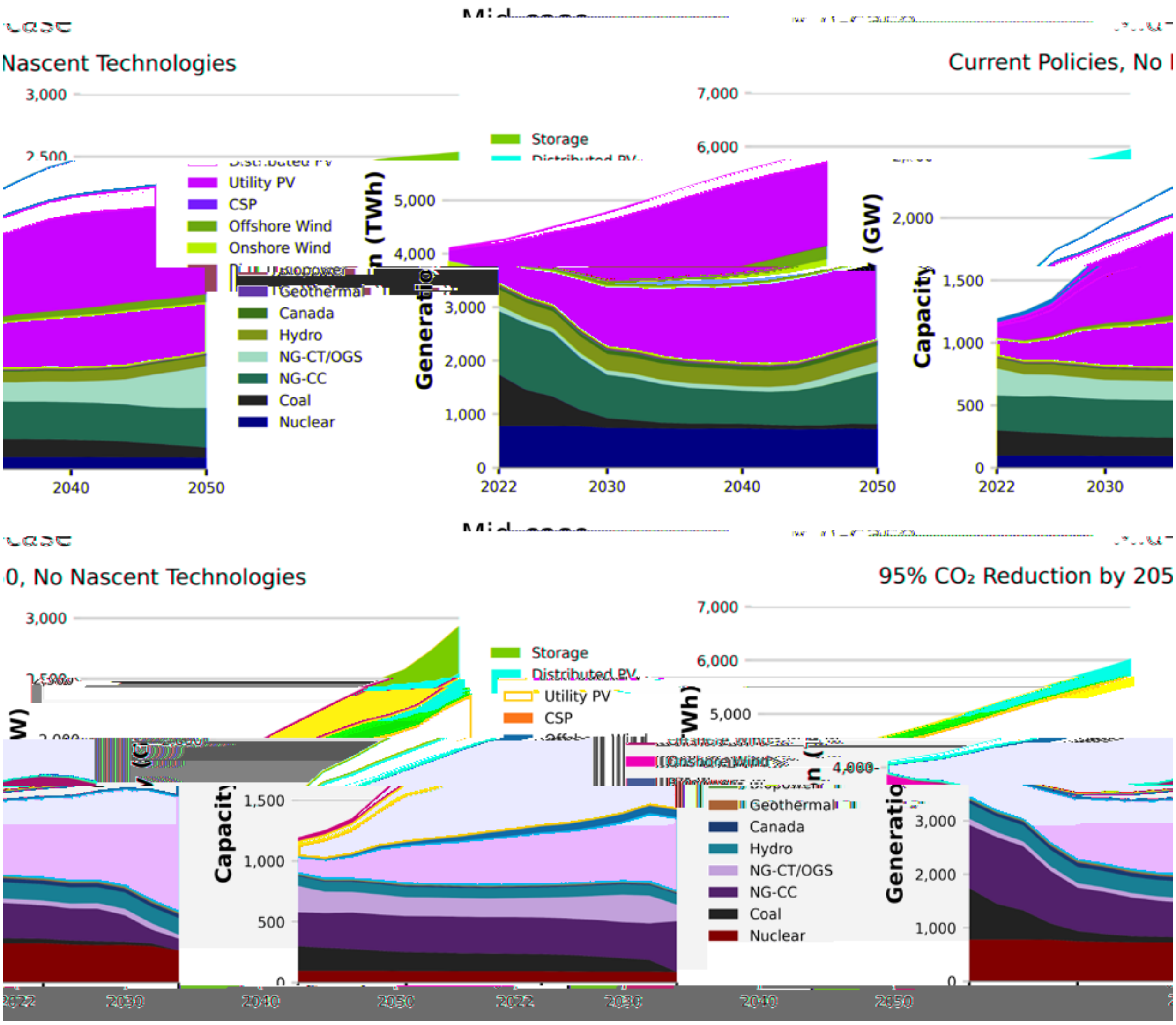

Figure ES-2. U.S. electricity sector generation (left) and capacity (right) over time for the two Mid-case scenarios where nascent generation technologies are not included. NG-CC is natural gas combined cycle, NG-CT is natural gas combustion turbine, OGS is oil-gas-steam.

As mentioned above, the Standard Scenarios include 13 sensitivity scenarios that vary factors such as fuel prices, demand growth, technology costs, resource availability, and transmission conditions. Each sensitivity is performed for the five combinations of CO_2 emission limits and technology sets that were shown for the Mid-cases in Figures ES-1 and ES-2.

Figure ES-3 shows the annual generation by technology class for the full suite of scenarios. Note that a set of sensitivities were performed with pre-IRA federal policies, and labelled in Figure ES-3, to illustrate IRA's impact. In general, IRA decreases generation from non-CCS natural gas and non-CCS coal, while increasing generation from solar, wind, CCS natural gas, and CCS coal. As previously mentioned in highlight #4 above, the reversal of some trends in the later years of some scenarios (e.g., the decline and subsequent rise of natural gas generation in the Current Policies Mid-case) is caused by the expiration of IRA's tax credits, which start to phase out after 2032 or when U.S. electricity sector CO_2 emissions reach 25% of 2022 levels (whichever is later). Not all scenarios meet this emission threshold, however, resulting in the tax credits persisting through the end of the modeled time period (2050) in those scenarios.

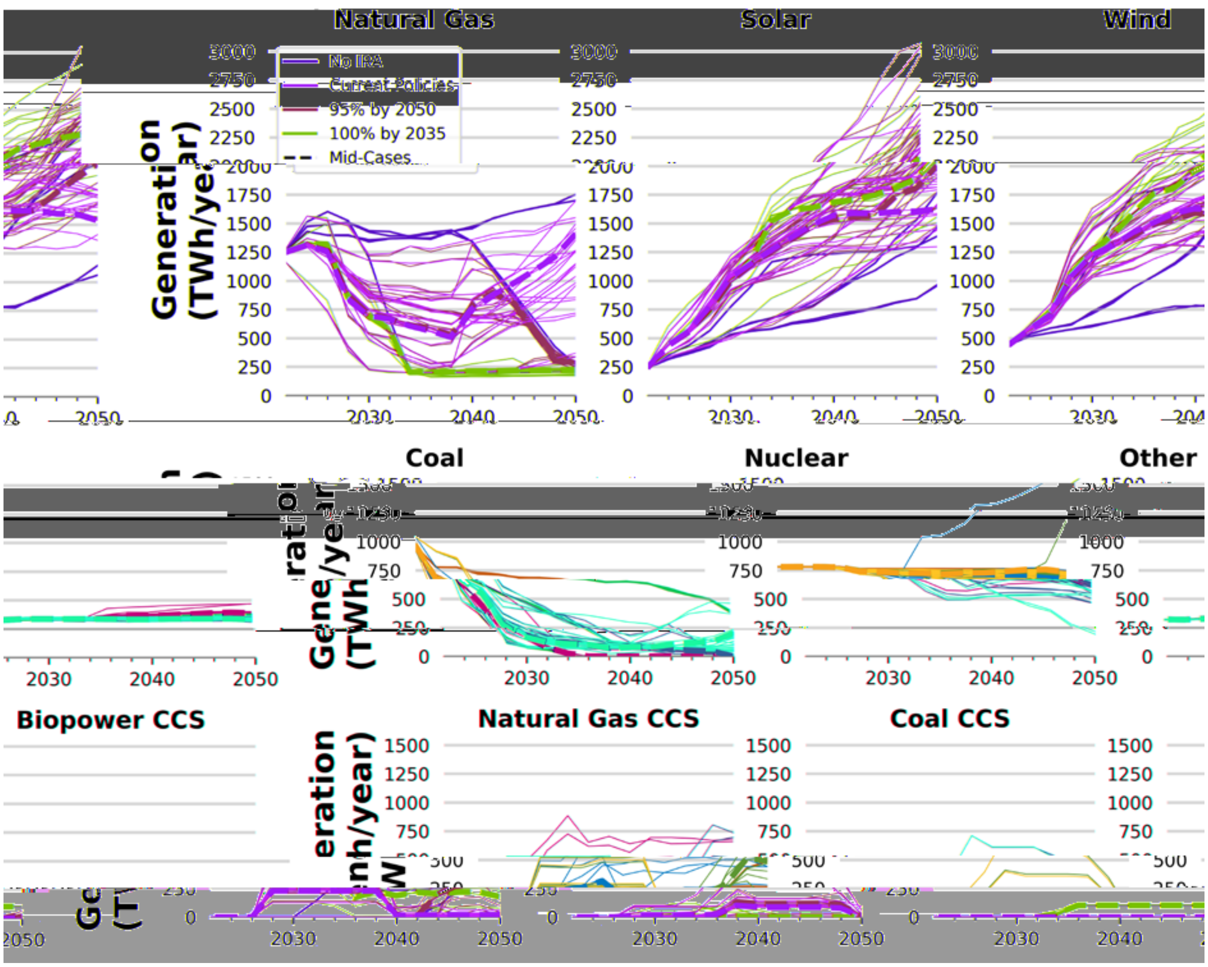

Figure ES-3. Generation across the suite of Standard Scenarios by fuel type. The Mid-case scenarios that include nascent technologies are shown with the heavier dashed lines. Solar includes PV, PV-battery hybrids, and CSP with and without thermal energy storage. Other includes biopower without CCS, geothermal, hydropower, renewable fuel combustion turbines, and landfill gas.

As a nascent technology, we emphasize that the quantity and timing of CCS deployment should be treated as particularly uncertain. We expect to better understand this technology in future analyses as data on its expected costs and performance as well as our modeled representation of the technology both improve.

Figure ES-4 shows the annual CO_2 emissions from electricity sector fuel combustion (less any CO_2 captured and stored with carbon removal technologies) for the full suite of scenarios. Note that the two lines with the highest values are the scenarios without IRA or national decarbonization policies, which are helpful in characterizing the impact of IRA on U.S. electricity sector CO_2 emissions.

As seen earlier with some generation trends, we also see CO_2 emission trends reverse in later years in the scenarios where the emission threshold specified in IRA is met (shown in Figure ES-4 as the red dotted line), and the tax credits correspondingly phase out.

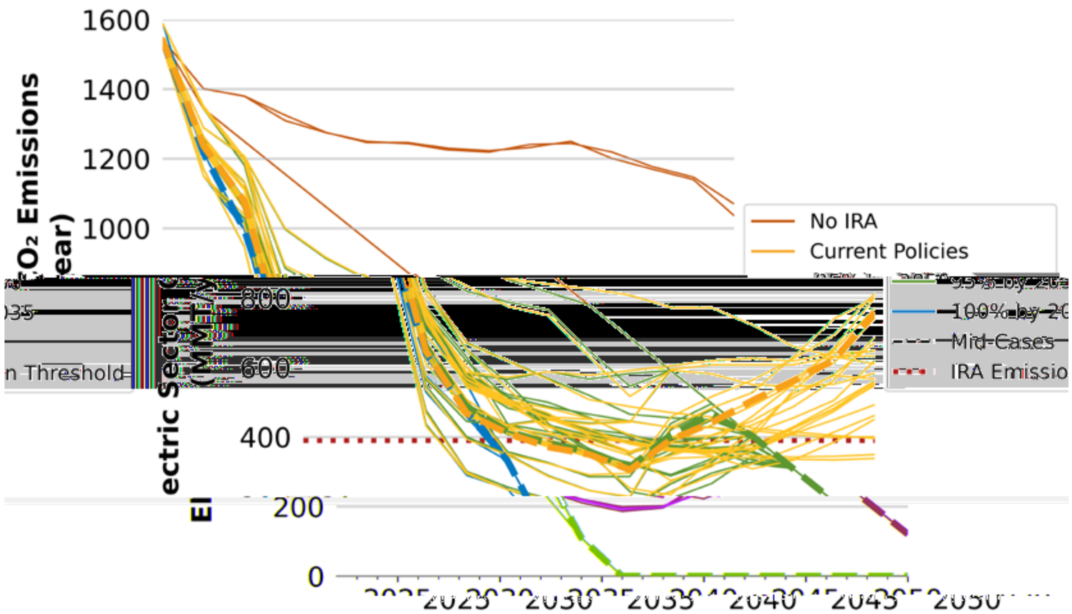

Figure ES-4. Electricity sector CO_2 emissions for the full suite of Standard Scenarios. The Mid-case scenarios with the full technology set (including nascent technologies) are shown with the heavier dashed lines. Emissions are only CO_2 emissions from direct combustion of fuel (i.e., stack emissions) less carbon captured by carbon removal technologies. The emissions do not include other greenhouse gases or pre- or post-combustion emissions. The emission threshold in IRA is specified relative to 2022 emissions, which are not yet known at the time of publication, and therefore approximated as the emissions from June 2021 through May 2022 (1560 MMT CO_2, for a corresponding threshold of 390 MMT CO_2).

Figure ES-5 compares the Mid-case (previously shown in Figure ES-1) against a sensitivity with identical assumptions except that IRA's PTC and ITC are extended through 2050. We can see that, when those credits do not phase out, renewable generators continue to be deployed in later years.

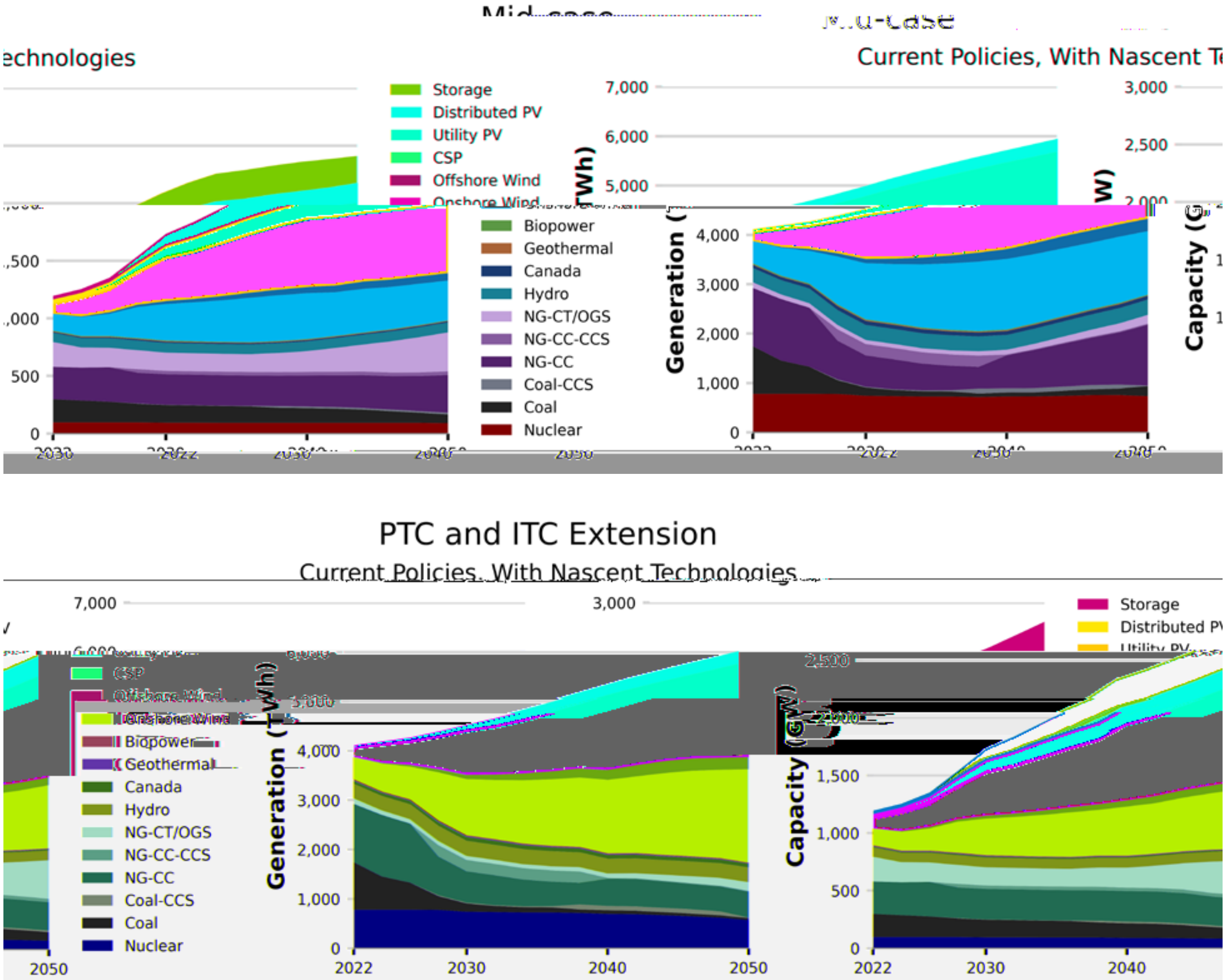

Figure ES-5. U.S. electricity sector generation (left) and capacity (right) over time for the Mid-case and a sensitivity where the PTC and ITC do not phase out

CSP is concentrating solar power, NG-CC is natural gas combined cycle, NG-CT is natural gas combustion turbine, and OGS is oil-gas-steam.

The remainder of this report summarizes key results from the 2022 Standard Scenarios suite and documents the input assumptions for each scenario. Data for these scenarios is available for viewing and downloading in the Standard Scenarios 2022 project at the aforementioned NREL Scenario Viewer.

Though many potential futures are included in this analysis, the set of scenarios is not exhaustive. Other NREL projects have explored certain aspects of these scenarios in more detail, such as the 100% Clean Electricity by 2035 Study and the Electrification Futures Study. Forthcoming studies include a more detailed analysis of the impacts of IRA and the impacts of transmission on the U.S. electricity sector. See https://www.nrel.gov/analysis/future-system-scenarios.html for a list of NREL's analysis of future power systems analyses.

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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 eighth[3] installment of the Standard Scenarios. This year's Standard Scenarios consist of 70 electricity sector scenarios for the contiguous United States that consider the present day through 2050 and include a representation of the Inflation Reduction Act of 2022.

The Standard Scenarios are simulated using the Regional Energy Deployment System (ReEDS) model, which projects utility-scale electricity sector evolution for the contiguous United States using a system-wide, least-cost approach subject to policy and operational constraints (Ho et al. 2021). ReEDS draws from the Distributed Generation Market Demand Model (dGen) for projections of behind-the-meter solar adoption. [4]

The objective of the Standard Scenarios is to explore a range of possible future conditions and how the U.S. electricity sector may evolve under those conditions. Although we strive to produce reasonable projections of the future, these projections should not be the sole basis for making decisions. We encourage analysts to draw from multiple scenarios within the full set, as well as draw from projections from other sources, to benefit from diverse analytical frameworks and perspectives when forming their conclusions about the future of the electricity sector.

Our models, in particular, have been designed to capture the unique traits of renewable energy generation technologies and the resulting implications for the evolution of the electricity sector. 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 that complements those provided by others.

Although the models used to develop the Standard Scenarios are sophisticated, they do not capture every relevant factor. For example, the models do not explicitly model supply chains, learning-by-doing, or permitting, as just several examples. Additionally, ReEDS does not have foresight, has a simplified representation of transmission networks, and takes a system-wide planning approach when making decisions rather than representing specific market actors or rules. 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).

In addition to this report, which focuses on high level trends, state-level outputs are available for viewing and downloading through NREL's Scenario Viewer.[5]

[3] See atb.nrel.gov/archive for the previous Standard Scenarios reports and data.

[4] 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.

[5] The data viewer (scenarioviewer.nrel.gov) 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 Suite of Scenarios

The 2022 Standard Scenarios comprise 70 scenarios that project the possible evolution of the contiguous United States' electricity sector through 2050. Scenario assumptions have been updated since 2021 to reflect the technology, market, and policy changes that have occurred in the electricity sector, and many modeling enhancements have been made (see Section A.2 in the appendix for a complete list of changes). Of particular note, this year's Standard Scenarios includes provisions from the Inflation Reduction Act of 2022 (IRA). The representation of the IRA provisions is discussed in Section 2.3.

The scenarios included in this report are summarized in Figure 1 (page 3). Details about specific scenario definitions and inputs are provided in Section A.1 of the appendix.

The 70 scenarios were selected to capture a wide range key drivers of electricity sector evolution, such as the cost and performance of technologies and fuel. The diversity of scenarios is intended to cover a range of potential futures. For example, in addition to considering traditional sensitivities such as demand growth and fuel prices, we also assess other factors that can impact the development of the electricity sector, such as transmission build-out and technology progress. We encourage those doing analyses that use data from these scenarios to draw from multiple scenarios, to reflect the inherent uncertainty in the evolution of the US electricity sector.

Although the scenario suite covers a wide range of futures, it is not exhaustive. We note that other NREL analyses have studied particular aspects of power sector evolution in more depth then is covered in this suite of scenarios. For example:

- The 100% Clean Electricity By 2035 Study has a broader suite of electricity sector decarbonization scenarios that explores different policy designs and the technologies that may come into play in such a future.
- The Electrification Futures Study explores a broader range of end-use electrification, provides more data describing those electrification trajectories, and conducts a more thorough exploration of the possible role of demand-side flexibility.
- The Storage Futures Study takes a closer look at the possible role of energy storage technologies.
- The annually released Cambium data sets provide a broader suite of metrics at hourly resolution for a subset of the Standard Scenarios.

Additionally, forthcoming work will explore the impacts of IRA in more detail than is presented here. See https://www.nrel.gov/analysis/future-system-scenarios.html for a more complete list of NREL's other future power systems analyses.

We note that, to enhance transparency, the ReEDS and dGen models and inputs we used to generate these scenarios are publicly available.[6]

[6] See www.nrel.gov/analysis/reeds and www.nrel.gov/analysis/dgen/.

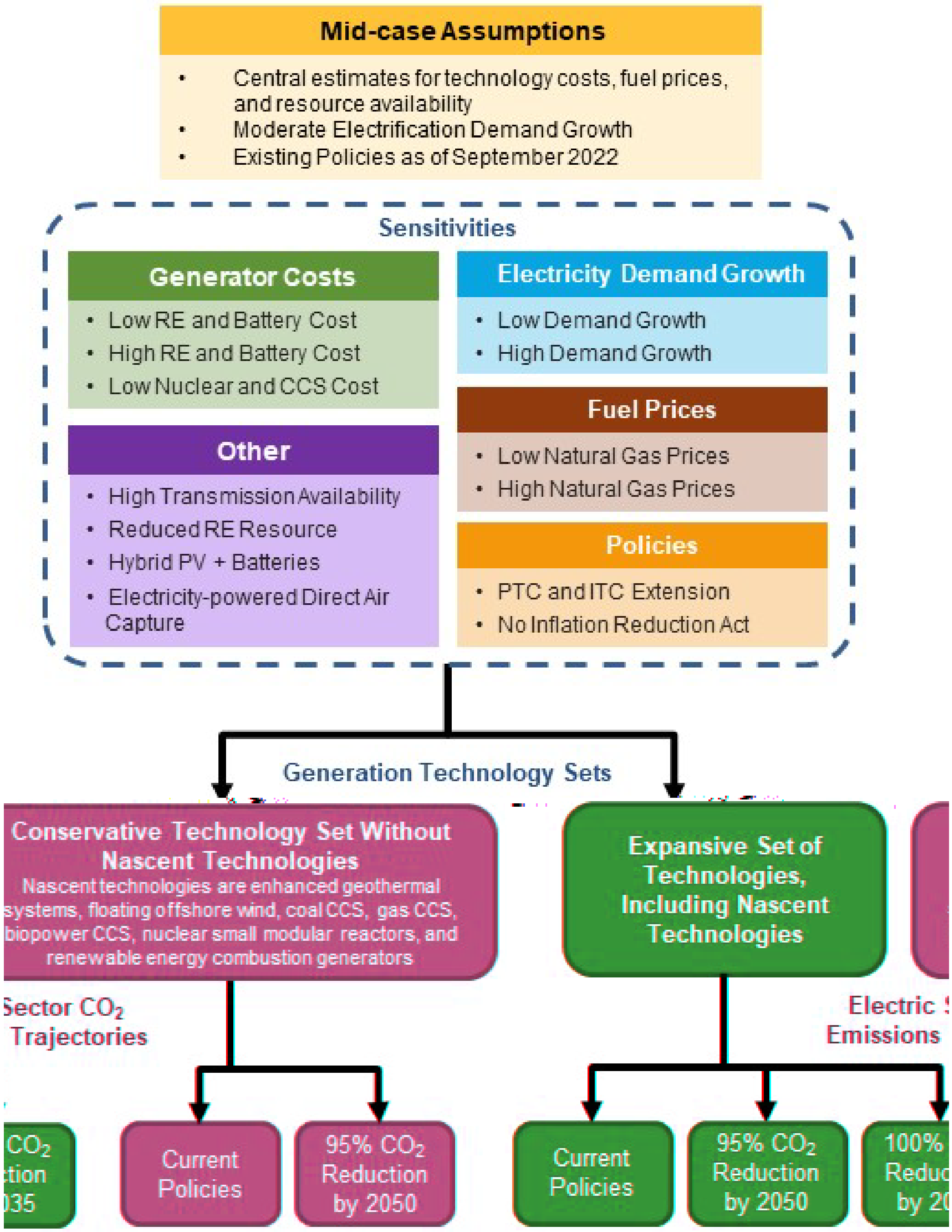

Figure 1. Summary of the 2022 Standard Scenarios. There are 70 scenarios, which are a product of 14 base assumptions (1 Mid-case set of assumptions plus 13 sensitivities), multiplied by 5 different permutations of generator technology sets and electricity sector emissions trajectories (14*5=70). RE is renewable energy, CCS is carbon capture and storage, PTC is production tax credit, and ITC is investment tax credit. Scenario details are in Table A-1 in the appendix. All scenarios reflect federal and state electricity policies enacted as of September 2022, other than the No Inflation Reduction Act sensitivity, which has state policies as of September 2022 but reflects federal policies as they were before IRA.

Note that the 100% by 2035 emission trajectory is not combined with the No Nascent Technologies set, because such a scenario requires more careful treatment than was feasible in this year's Standard Scenarios (for example, in examining and interpreting the exceptionally rapid generator buildouts). For readers interested in a more detailed exploration of zero-carbon systems under a 2035 timeframe, we direct them to NREL's 100% Clean Electricity by 2035 Study (Denholm et al. 2022).

2.1 Definition of Decarbonization Scenarios in the Standard Scenarios

In the 2022 Standard Scenarios, two electricity sector CO_2 trajectories are applied to a subset of the scenarios: the 95% Reduction by 2050 and the 100% Reduction by 2035. These trajectories correspond to a percentage reduction in net U.S. electricity sector CO_2 emissions relative to 2005 emissions.

These trajectories are implemented as a national electricity sector CO_2 constraint. The CO_2 constraint only apply to the U.S. electricity sector. None of the scenarios in this analysis model international or economy-wide decarbonization, which would impact factors such as fuel prices, generator costs, and the magnitude and shape of electricity demand.

The trajectories limit the net electricity sector emissions, meaning that the constraint is applied to CO_2 emissions from the direct combustion of fuel for electricity generation, less any CO_2 captured and stored through carbon capture technologies (biopower with CCS or direct air capture, if present). The emission limit does not incorporate other greenhouse gases, emissions from precombustion or post-combustion activities such as fuel extraction and transport (other than the CO_2 removed from the atmosphere during feedstock growth for biopower with CCS), or the emissions induced by construction or decommissioning activities.

Note that, in the scenarios that exclude nascent technologies, there are no carbon removal options—and that direct air capture is only included in the sensitivity which bears its name.

The definition of a CO_2 constraint given above is only one possible definition—others may include the CO_2 equivalence of other greenhouse gasses or include non-combustion emissions (e.g., emissions from fuel extraction, processing, and transport). Furthermore, other definitions may involve different approaches to the accounting around carbon removal, including completely prohibiting offsets. Other possible definitions of power sector decarbonization were explored in NREL's 100% Clean Electricity by 2035 Study.

2.2 Technology Sets

Each scenario in the 2022 Standard Scenarios has one of two different generation technology sets available to the ReEDS model: a relatively conservative set that only has technologies that have achieved commercial procurement in the United States and a broader set that includes nascent technologies (Table 1).

Table 1. Generation Technology Classification in the 2022 Standard Scenarios

Technology Group	Technologies
Established	• Electric batteries • Biopower • Coal • Concentrating solar power (CSP) with and without thermal energy storage • Distributed rooftop solar photovoltaics (PV) • Natural gas combined cycles (NG-CC) • Natural gas combustion turbines (NG-CT) • Conventional geothermal • Hydropower • Landfill gas • Conventional nuclear • Oil-gas-steam (OGS) • Pumped storage hydropower • Utility-scale PV • Utility-scale PV-battery hybrids[a] • Onshore wind • Fixed-bottom offshore wind
Nascent	• Biopower CCS • Coal CCS • Enhanced geothermal systems • Floating offshore wind • Natural gas CCS (NG-CC-CCS) • Nuclear small modular reactors (SMR) • Renewable fuel combustion turbine (RE-CT)

[a] PV-battery hybrids are considered an established technology, but they are not included in the Mid-case set of assumptions (and therefore in most scenarios) because data was lacking for modeling it in the "Low Renewable Resource" sensitivity. To enable users to see how its presence influences the projections, it is included in the sensitivities that bear its name. For additional analysis of PV-battery hybrids by NREL, see (Murphy, Brown, and Carag 2022)

Note that electricity-powered direct air capture is not included as an investment option, other than the sensitivity that bears its name.

Renewable fuel combustion turbines (RE-CT) are combustion generators that use a renewably derived input fuel (e.g., hydrogen, biodiesel, ethanol, or green methane) that is assumed to cost \$20/MMBtu in 2022 dollars. See section A.1 in the appendix for more details.

The classification of technologies as either nascent or established was an analytical judgement call based on the technology's readiness level, the current installed capacity globally, the current presence or absence of the technology in resource plans in the U.S., the level of understanding of permitting and sitting challenges, and the breadth and quality of future performance and cost estimates from multiple institutions.

The designation of a technology as nascent is not intended to pass judgement on the difficulty or likelihood of the technology ultimately achieving commercial adoption. Indeed, many of the technologies have high technology readiness levels, and some have operational demonstration plants. Nonetheless, even if a technology is technically viable, there is still great uncertainty about its future cost and performance, as well as a lack of understanding of other considerations relevant to projecting their adoption, such as siting preferences and restrictions. Given these uncertainties, we chose to present a set of scenarios that does not include these technologies.

2.3 Representation of the Inflation Reduction Act of 2022

The 2022 Standard Scenarios includes a representation of the main electricity sector provisions from the Inflation Reduction Act of 2022 (IRA). We note that, while we believe that our representation of IRA is adequate to characterize the type of electric-sector trends explored in this report, not all of IRA's provisions are represented. Additionally, as with any modeling of complex policy, the representation of the provisions are generally simplifications. We highlight these omissions and simplifications below, and where analysts are using the data provided to perform derivative analyses, we encourage them to reflect critically on whether any omission is impactful for their specific purpose.

Four electricity sector tax credits are represented in ReEDS:

- **Production Tax Credit (PTC):** $26/MWh for 10 years (2022 dollars) plus a bonus credit that starts at $1.3/MWh and increases to $2.6/MWh by 2028
- **Investment Tax Credit (ITC):** 30%, plus a bonus credit that starts at an additional 5% and increases to 10% by 2028 (for totals of 35% and 40% respectively)
- **Captured CO_2 Incentive (45Q):** $85 per metric ton of CO_2 for 12 years for fossil-CCS and bioenergy-CCS, and $180 per metric ton of CO_2 for 12 years for direct air capture; nominal through 2026 and inflation adjusted after that
- **Existing Nuclear Production Tax Credit (45U):** This tax credit is $15/MWh (2022 dollars), but it is reduced if the market value of the electricity produced by the generator exceeds $25/MWh. As a simplification, this dynamic calculation was not directly represented in ReEDS. Instead, to represent the effect of this provision, existing nuclear generators are not subject to economic retirement in ReEDS through 2032.

Note that IRA allows for bonus credits for both the PTC and ITC (but not applicable to 45Q or 45U) if a project either meet certain domestic manufacturing requirements or is in an "energy community." Projects can obtain both bonus credits if they meet both requirements, which would equate to $5.2/MWh for the PTC and 20% for the ITC. In ReEDS, we assume projects will, on average, capture one of the bonus credits by 2028, the value of which is expressed in the summary above. In practice, there will likely be greater diversity of captured credits amongst projects. Relatedly, the values above are based on the assumption that all projects will meet the prevailing wage requirements.

Under IRA, eligible projects can select whether to take the PTC or the ITC. As implemented in ReEDS, however, an a priori analysis was performed to estimate which credit was most likely to be more valuable, and the technology was assigned that credit. The assignments are:

- **PTC:** Onshore wind, utility-scale PV, and biopower
- **ITC:** Offshore wind, CSP, geothermal, hydropower, new nuclear, pumped storage hydropower, distributed PV, and batteries.

In previous implementations of tax credits in ReEDS, the value of tax credits was reduced by 33% as a simple representation of the costs of monetizing the tax credits (such as tax equity financing). Due to provisions in IRA that make it easier to monetize the tax credits, that cost penalty is reduced to 10% for non-CCS technologies and 7.5% for CCS technologies.[7] These cost penalties are not reflected in the values given for each incentive above.

The PTC and ITC are scheduled to start phasing out when electricity sector emissions fall below 25% of 2022 levels, or 2032, whichever is later. Because 2022 emissions are not known at the time of publication, the emissions are estimated as the emissions from June 2021 through May 2022 (1560 MMT CO_2). This equates to a phase-out threshold of 390 MMT CO_2. The 45Q and 45U credits do not have a dynamic phaseout and are instead just scheduled to end at the end of 2032.

In the dGen model, distributed PV was assumed to take an ITC: the 25D credit for residential, and the Section 48 credit for commercial and industrial. For residential projects placed in service through 2032 the ITC was assumed to be 30%, declining to zero for projects placed in service in 2036. For commercial and industrial projects coming online through 2035 the ITC was assumed to be 40%, dropping to zero after that. These representations are simplifications, as there can be greater diversity in captured value depending on factors such as ownership type and tax status. Furthermore, due to limitations of the models used in this study, the dynamic phase-out of the Section 48 ITC was not reflected. In practice, many scenarios did not cross the emissions threshold specified in IRA at this point, and therefore the adoption of commercial and industrial distributed PV in the later years of those scenarios was potentially underestimated.

IRA includes additional bonus credits (up to 20%) for up to 1.8 GW per year for solar facilities that are placed in service in low-income communities. The dGen model runs used in this analysis did not have an explicit representation of that additional bonus credit. Instead, 0.9 GW per year of distributed PV was added to the original dGen estimates through 2032. The estimate of 0.9 GW reflects the assumption that some of the projects capturing the bonus credit may not be additional (i.e., they would have occurred anyway even if the bonus credit was not available).

All the IRA tax credits are assumed to have safe harbor periods, meaning a technology can capture a credit as long as it started construction before the expiration of the tax credit. The maximum safe harbor periods are assumed to be 10 years for offshore wind, 6 years for CCS and nuclear, and 4 years for all other technologies. Generators will obtain the largest credit available within their safe harbor window, meaning that once a credit starts to phase down or terminate, ReEDS assumes that efforts were made to start construction at the maximum length of the safe

[7] CCS projects are eligible for a direct pay option for the first 5 years of the 45Q credit or until 2032 (whichever comes first), with the credits returning to non-refundable status after that point. The lower monetization penalty is meant to approximate the benefit of the direct pay option.

harbor window before the unit came online. In practice this means ReEDS will show generators coming online and capturing the tax credits for several years beyond the nominal year in which they expired.

The impact of manufacturing incentives in IRA are not explicitly represented. Instead, it is simply assumed that the incentives will have no net impact on technology costs and will be sufficient to enable the assumptions about domestic content bonus credits described above.

The IRA provisions related to hydrogen and biofuels production are not explicitly represented, although the incentives for renewable fuels could be a factor in reaching the cost of $20/MMBtu for delivered renewable fuels for renewable combustion turbines that was assumed in these scenarios. The electrical load that may be caused by fuel production is not included in these scenarios.

Lastly, IRA includes demand-side provisions. A modified version of a demand trajectory from NREL's Electrification Futures study is used to represent slightly greater electrification as a result of IRA. The approach for this demand trajectory is described in Section A.1 in the appendix. We emphasize that the use of this modified trajectory is just an initial approximation of the impact of the demand-side IRA provisions, and we expect more thorough modeling and analysis to be developed later.

3 The Mid-Case Scenarios

The Mid-case scenarios use central assumptions for demand growth, resource availability, fuel price, and technology inputs (see Figure 1, page 3, for a summary of those assumptions and Appendix A.1 for details about the assumptions). In this way, the Mid-case scenarios provide reference points 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 (page 11) shows the generation and capacity mix through 2050 for the Mid-case scenarios, with nascent technologies included, under the three levels of electricity sector decarbonization. The Current Policies trajectory does not impose any CO_2 emission limit other than those already in place, the 95% by 2050 trajectory imposes a net 95% reduction in national electricity sector CO_2 emissions by 2050 relative to 2005, and the 100% by 2035 trajectory requires that national CO_2 emissions are net zero by 2035. Direct air capture is not enabled in these scenarios, but biopower with carbon capture is available to offset stack emissions from carbon-emitting generators.

All three scenarios see significant increases in wind, solar, and storage deployment. In part because of this deployment, all three scenarios hit the 75% emissions reduction threshold specified in IRA, and consequently the PTC and the ITC phase out in the 2030s. In the scenario with current policies, this results in a reversal of several trends, as the absence of the PTC results in wind capacity declining in the 2040s (from retirements that are not repowered) and natural gas generation increasing. The tax credits also expire in the other two scenarios, but their decarbonization trajectories largely prevent the same reversals.

With the increased value of the 45Q incentive for captured carbon in IRA, all three scenarios see fossil-CCS deployed. In both the scenario with current policies as well as the 95% by 2050 scenario there is an initial retrofitting of natural gas plants with CCS, which then operate at their maximum capacity factor for the 12-year duration of the 45Q credit. However, once the credit expires for those plants, they revert to much lower capacity factors while primarily providing firm capacity.[8] In the 100% by 2035 scenario, natural gas units are likewise retrofitted in the late 2020s and their generation contribution remains consistent after that even as they lose the 45Q credit, as their carbon emissions are offset by bioenergy with CCS plants.

The Current Policies and 95% by 2050 scenarios also see coal-CCS retrofits in the 2030s. The deployment of these plants, which is later than natural gas CCS, is driven by the cost trajectory for retrofitting coal plants (see Section A.1 in the appendix), which is assumed to be the difference between greenfield CCS and non-CCS plants, plus a 20% adder. We emphasize that, as with all technologies, and especially nascent technologies, the ultimate deployment of these generators is sensitive to their future costs. More rapid reductions in the cost of retrofitting could see earlier deployment of coal-CCS, whereas slower cost reductions could see the 45Q credit terminate before widespread retrofitting becomes economical.

[8] Note that ReEDS does not have the ability to operate CCS generators with their capture equipment turned off, or to remove the equipment entirely. In practice, these generators may disable their capture equipment once they are no longer capturing the 45Q credit.

In addition to the fossil-CCS, natural gas capacity without CCS remains in both decarbonization scenarios despite the stringent CO_2 limits. The capacity persists by running at lower utilization rates and, in the 100% by 2035 scenario, by having its emissions offset using biopower with CCS. These natural gas generators, along with other resources such as nuclear, hydropower, storage, and geothermal plants, provide a 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).

Bioenergy with CCS generation capacity is deployed in both the 95% by 2050 scenario and the 100% by 2035 scenario. Renewable fuel combustion turbines are also deployed, primarily for providing firm capacity, in the 100% by 2035 scenario. We note that IRA includes incentives for hydrogen production (one of several potential fuels that could be used in renewable generators), and while this analysis did not explicitly incorporate that incentive, it could play a role in bringing the cost of hydrogen down to the $20/MMBtu assumed in these scenarios.

Existing nuclear plants are not subject to economic retirement through 2032, due to ReEDS' interpretation of the IRA incentives for existing nuclear, and beyond 2032, they generally remain sufficiently competitive to avoid early retirement,[9] resulting in a near-constant level of nuclear capacity and generation through 2050. No new nuclear is added in the Mid-case scenarios, even with stringent CO_2 limits.

[9] Nuclear power plants have an assumed lifetime of 80 years within the model unless an earlier retirement date has been announced.

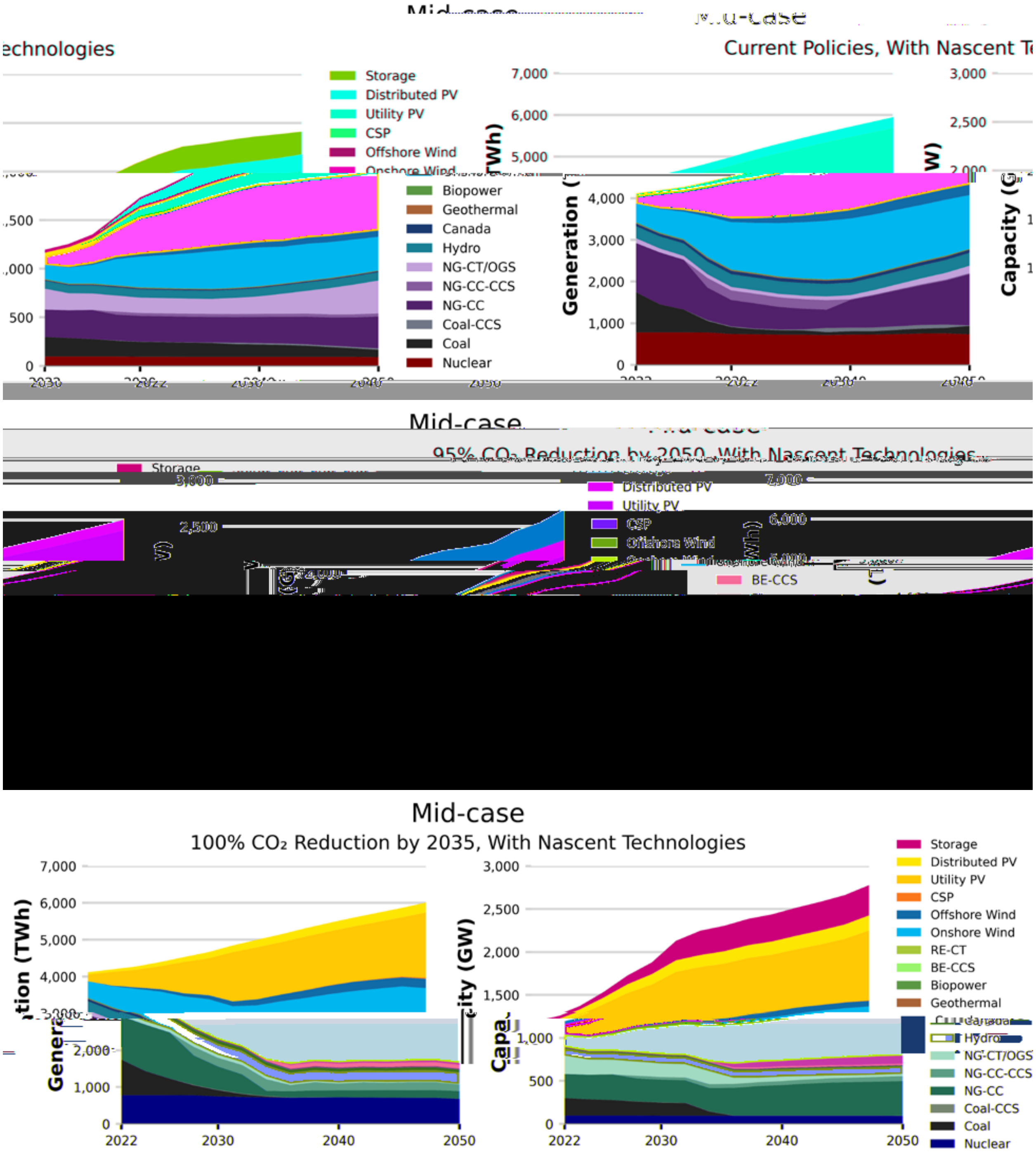

Figure 2. U.S. electricity sector generation (left) and capacity (right) over time for the three Mid-case scenarios with both established and nascent generation technologies. NG-CC is natural gas combined cycle, NG-CT is natural gas combustion turbine, OGS is oil-gas-steam, RE-CT is renewable fuel combustion turbine, BE is bioenergy, CSP is concentrating solar power, and CCS is carbon capture and storage.

The three panels in Figure 2 show the Mid-case scenarios where all generation technologies are included, including nascent technologies. Figure 3 (page 12) shows the generation and capacity projections for the two Mid-cases where nascent technologies are excluded.

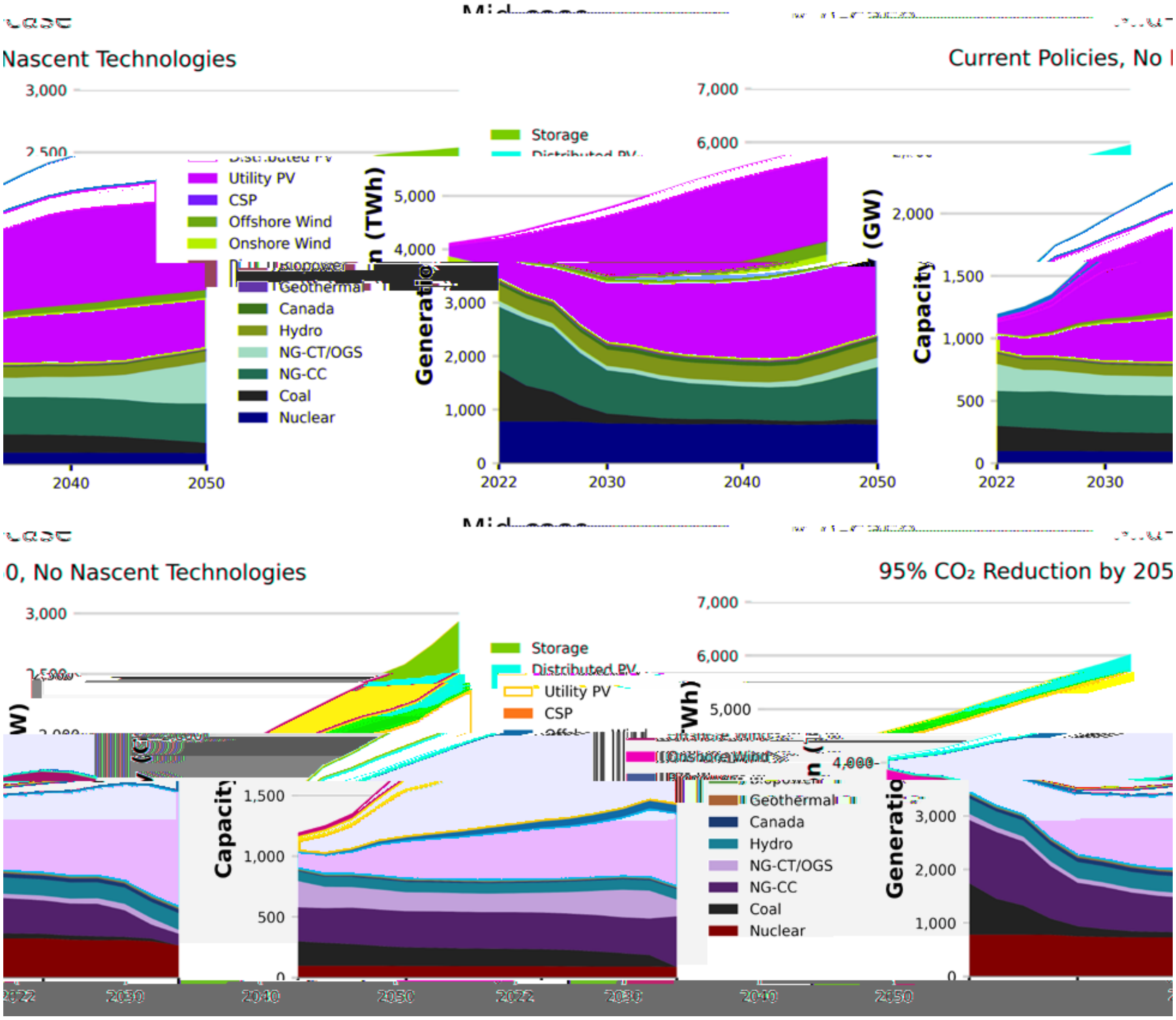

Figure 3. U.S. electricity sector generation (left) and capacity (right) over time for the two Mid-case scenarios where nascent generation technologies are not included. NG-CC is natural gas combined cycle, NG-CT is natural gas combustion turbine, OGS is oil-gas-steam.

Table 2 and Table 3 show the generation fraction for the major fuel types in 2032 (a decade from the release of this report) and 2050, respectively for the Mid-case scenarios with different levels of CO_2 emission limits. Unlike previous iterations of the Standard Scenarios, there is a fair degree of similarity in the 2032 mixtures between these scenarios, in large part because the IRA-induced emissions reduction outpaces the 95% by 2050 decarbonization trajectory and is only moderately behind the 100% by 2035 trajectory. However, there is much greater variation in the 2050 mixtures.

Table 2. Generation Fraction in 2032 for Each Fuel Type in the Mid-Cases under Three Levels of CO_2 Requirements

Fuel Type	Current Policies	Current Policies, No Nascent Technologies	95% by 2050	95% by 2050, No Nascent Technologies	100% by 2035
Total Renewables	60%	61%	60%	61%	62%
Wind	28%	28%	28%	29%	30%
Solar	25%	25%	24%	25%	25%
Nuclear	16%	16%	16%	16%	16%
Total Natural Gas	19%	18%	19%	18%	18%
Non-CCS Natural Gas	14%	18%	14%	18%	12%
CCS Natural Gas	5%	N/A	5%	N/A	5%
Total Coal	3%	3%	3%	3%	2%
Non-CCS Coal	3%	3%	3%	3%	2%
CCS Coal	0%	N/A	0%	N/A	0%

Table 3. Generation Fraction in 2050 for Each Fuel Type in the Mid-Cases under Three Levels of CO_2 Requirements

Fuel Type	Current Policies	Current Policies, No Nascent Technologies	95% by 2050	95% by 2050, No Nascent Technologies	100% by 2035
Total Renewables	59%	66%	73%	84%	79%
Wind	26%	30%	34%	40%	38%
Solar	27%	30%	33%	38%	35%
Nuclear	12%	12%	12%	10%	11%
Total Natural Gas	24%	19%	13%	5%	7%
Non-CCS Natural Gas	24%	19%	5%	5%	4%
CCS Natural Gas	<0.5%	N/A	8%	N/A	3%
Total Coal	4%	2%	0%	0%	0%
Non-CCS Coal	3%	2%	0%	0%	0%
CCS Coal	<0.5%	N/A	0%	N/A	0%

Comparison with Other Reference Case Scenarios

Here, we compare the Current Policies Mid-case projection with recent projections from three other organizations: the U.S. Energy Information Administration (EIA), the International Energy Agency (IEA), and BloombergNEF (BNEF).[10] Note that the most recent projections from the non-NREL organizations all were published before the passage of IRA and therefore do not include its effects, hindering effective comparison. Nonetheless, we plot these results to enable readers to compare NREL's historical projections against other organizations, and to place NREL's new projections alongside a wider range of pre-IRA estimates.

Two other early analyses of IRA's potential impact have estimated that it could bring annual U.S. economy-wide greenhouse gas emissions down to 40% of 2005 levels by 2030 (DOE 2022) and 58% of 2005 levels by 2030 (Jesse D. Jenkins et al. 2022). Note that the projections shown in Figure 4 are only for the U.S. electricity sector, not the whole economy.

Although NREL and most of these organizations publish multiple scenarios that span a wide range of assumptions, this comparison uses only the "reference" scenarios.[11] Note that the decrease in renewable energy share and increase in CO_2 emissions in this year's projections from NREL are driven mostly by an increase in natural gas generation from already-existing generators, not from a decrease in renewable energy generation. This is caused by the expiration of IRA's tax credits, as discussed previously in this report. For reference, a line has been added showing the trends in NREL's projections under Mid-case assumptions, but where IRA's PTC and ITC are extended through the modeling horizon.

[10] The NREL scenario is the Current Policies (previously No New Policy) Mid-case including nascent technologies. The BNEF case is the New Energy Outlook scenario. The EIA case is the Annual Energy Outlook Reference Case. The IEA is the World Energy Outlook Stated Policies scenario. Note that the IEA's *World Energy Outlook 2022* was not yet available at the time of this writing and that in 2021 BNEF changed their forecasts to be centered on the pathways for power sector decarbonization, and therefore are no longer updated here.

[11] The input assumptions, including the policies represented differ among these reference scenarios.

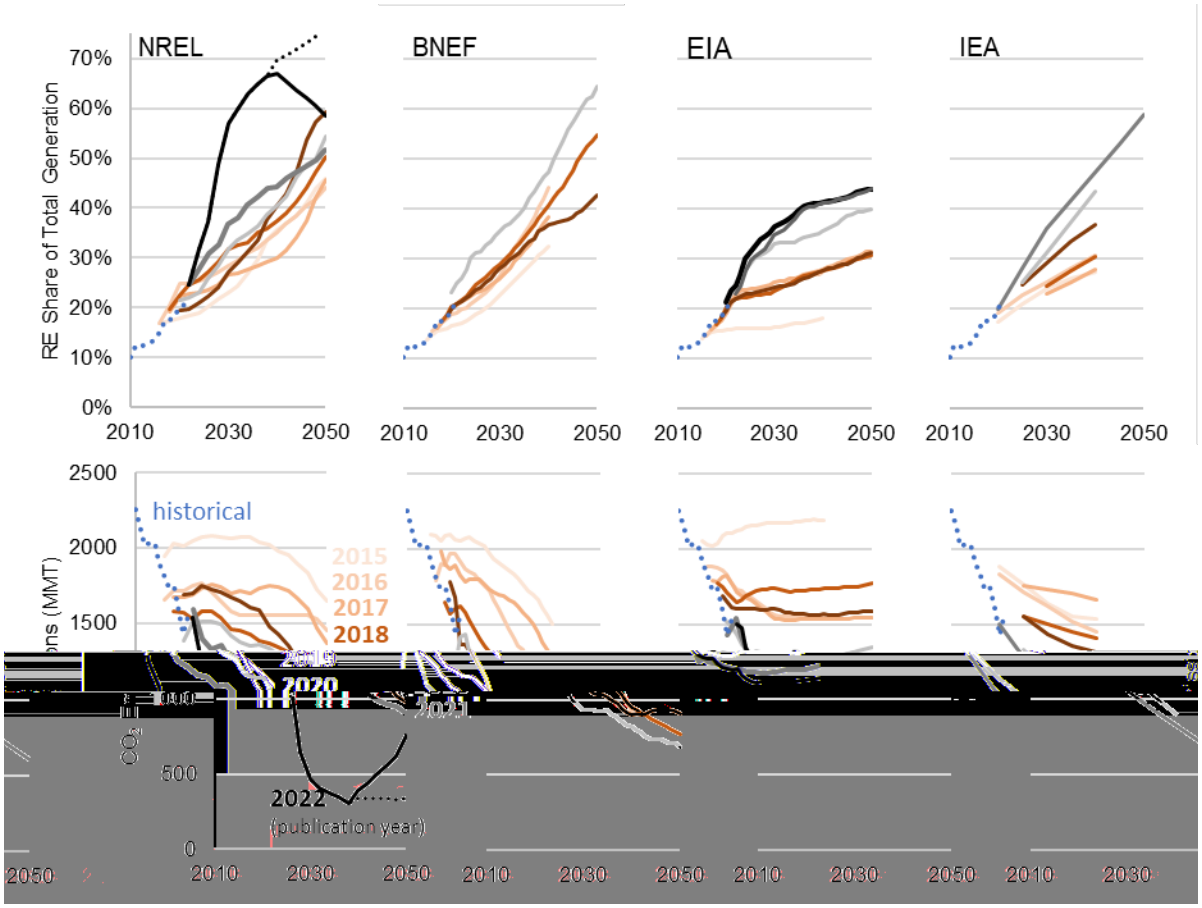

Figure 4. Renewable energy generation fraction (top) and electricity sector CO_2 emissions (bottom) from the organizations and publication years indicated

Only reference case scenarios are shown. The dashed black line on the NREL panels shows projections from the *PTC and ITC Extension* sensitivity with Current Policies and nascent technologies (where the PTC and ITC are made to persist through the end of the modeling horizon).

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-cases share many underlying assumptions, it is important to understand how the electric grid might evolve over a broader range of futures.

We note that, because sensitivities are perturbations off of the Mid-case set of assumptions, there is a natural clustering of projections around the Mid-case scenarios. This clustering should not be interpreted as indicating a higher likelihood.

Figure 5 (page 17) 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 Current Policies scenarios, and its contribution in the scenarios with national emissions limits is generally less but also sensitive to the specific policy (95% or 100% decarbonization) and the presence or absence of carbon removal technologies. Non-CCS coal generation tends to decline over time, although some of the decline is from the retrofitting of existing generators with CCS. Nuclear generation remains largely 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 (without a corresponding decline in nuclear capacity) due to decreases use induced by relatively higher VRE deployment.

Some scenarios have a reversal in trends in the 2040s (e.g., the increase in natural gas and decline in wind generation in the Current Policies Mid-case) that is caused by the expiration of the PTC and ITC once emissions have been reduced by 75%. Not all Current Policies scenarios hit that emissions threshold.

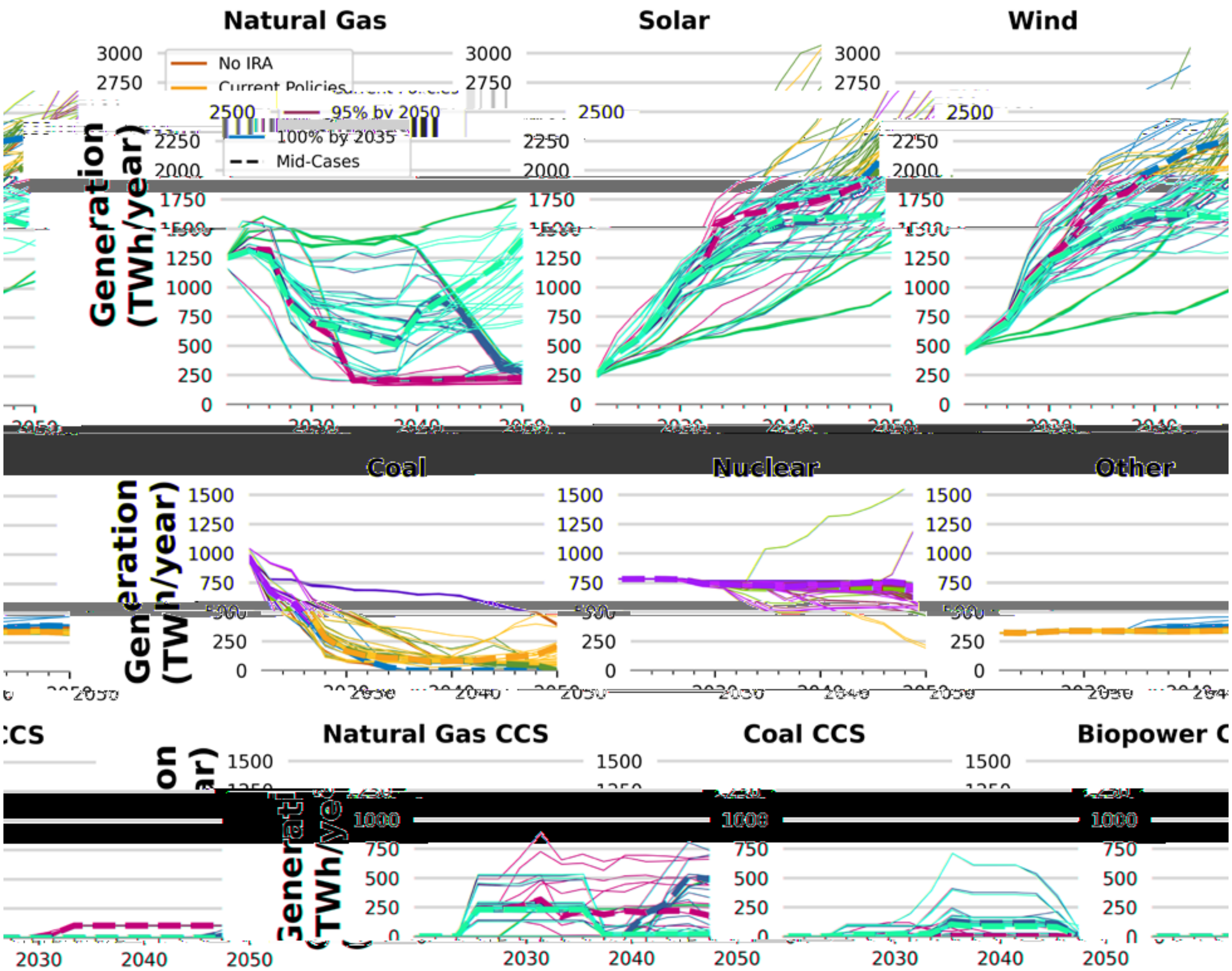

Figure 5. Generation by fuel type across the Standard Scenarios. The Mid-case scenarios with the full technology set (including nascent technologies) are shown with the heavier dashed lines. Solar includes PV, PV-battery hybrids, and CSP with and without thermal energy storage. Other includes hydropower, geothermal, biopower without CCS, landfill gas, and renewable fuel combustion turbines

Natural gas capacity (see Figure 6, page 18) grows in most scenarios, although the scenarios with the 100% by 2035 decarbonization trajectory see a slight reduction in capacity. Even when it sees declines, natural gas capacity remains similar or greater than current levels, largely because it is a low-cost source of firm capacity, even in scenarios with limited natural gas generation. In the scenarios with national emissions constraints, the natural gas generators provide firm capacity while lowering their utilization rates, retrofitting with CCS, or offsetting their emissions with carbon removal technologies. Solar and wind have the widest range of 2050 deployment, and they are sensitive to the assumed technology costs, resource availability, policy assumptions, and transmission availability.

As observed in the previous generation plot, some scenarios have a reversal in trends in the 2040s (e.g., the decline in wind capacity in the current policies Mid-case) that is caused by the expiration of the PTC and ITC once emissions have been reduced by 75%. Other drivers of variation in capacity buildouts are the costs of wind and solar, fuel costs, assumptions about resource availability, the rate of load growth, the presence or absence of nascent technologies, and the presence or absence of national CO_2 constraints.

Figure 6. Capacity by fuel type across the Standard Scenarios. The Mid-case scenarios with the full technology set (including nascent technologies) are shown with the heavier dashed lines. Solar includes PV, PV-battery hybrids, and CSP with and without thermal energy storage. Other includes hydropower, geothermal, biopower without CCS, landfill gas, and renewable fuel combustion turbines.

Total renewable energy share, which is defined as the fraction of total generation that is from renewable energy generators, ranges from approximately 55% to over 80% in 2050 (other than the non-IRA sensitivities with current policies, both with and without nascent technologies, which reaches approximately 45%, see Figure 7). From the generation figures above (Figure 5), the increase in renewable energy deployment is primarily from wind and solar. Unlike previous editions of the Standard Scenarios, the renewable energy share is not generally influenced by the national emissions constraints until the early 2030s for the 100% by 2035 scenario and the late 2040s for the 95% by 2050 scenario. This is because the IRA-induced emissions reductions generally outpace the 95% by 2050 decarbonization trajectory through the late 2040s and is only moderately behind the 100% by 2035 trajectory until the early 2030s—meaning that those policies often do not become binding until later years. 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.

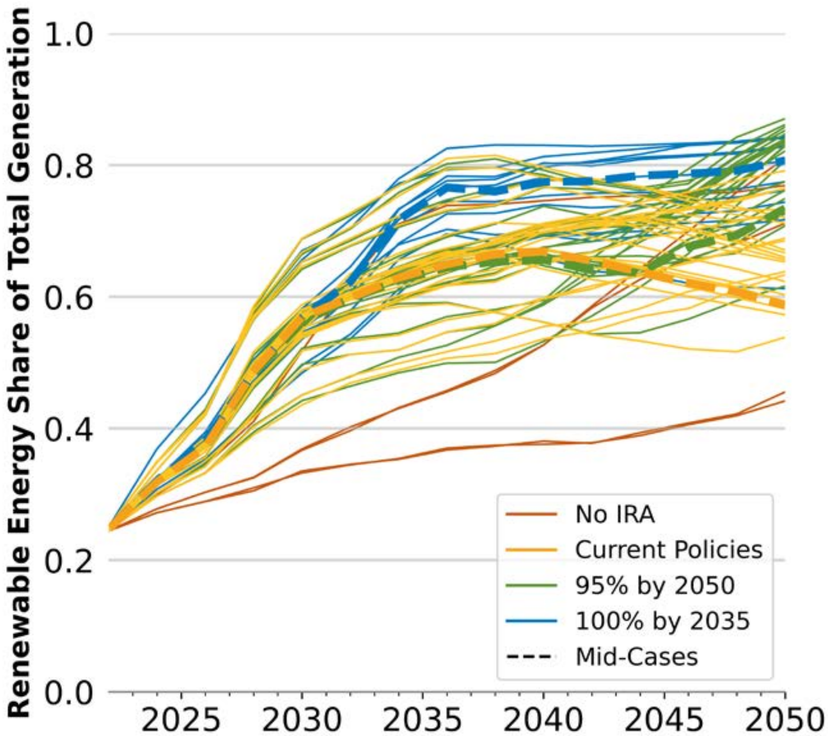

Figure 7. Renewable energy share over time across the Standard Scenarios. The Mid-case scenarios with the full technology set (including nascent technologies) are shown with the heavier dashed lines. Renewable energy share is defined as annual renewable energy generation divided by total generation.

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 buildouts 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, thereby increasing the value of transmission.

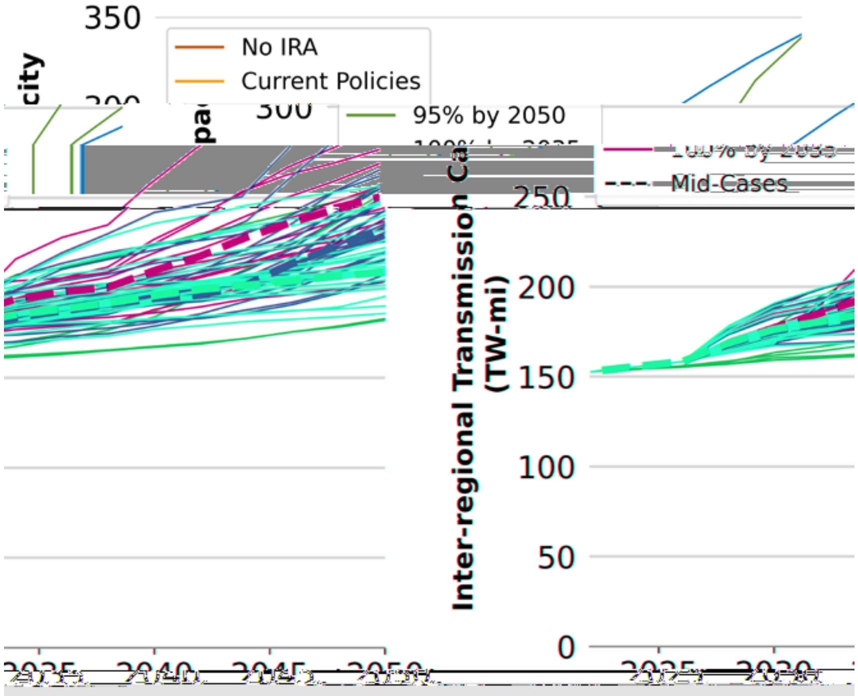

Figure 8. Interregional transmission capacity over the Standard Scenarios. The Mid-case scenarios with the full technology set (including nascent technologies) are shown with the heavier dashed lines. This reported capacity does not include the capacity of spur lines for connecting wind and solar plants to the transmission system.

Electricity sector CO_2 emissions are shown in Figure 9 (page 21). Emissions decline in all scenarios, even those without an emission limit. The two scenarios with the highest emissions are the sensitivities without IRA or national emissions constraints, as labeled in Figure 9.

As seen in other metrics, there can be a reversal of emissions trends in some scenarios, caused by the expiration of the PTC and ITC when emissions go below 25% of their 2022 level (shown in Figure 9 as the red dotted line). There can be a several-year lag from when the IRA threshold is passed before the emissions trend starts to reverse; this is caused by safe-harbor provisions that allow generators that are placed in service several years after the nominal expiration of the tax credits to still capture them.

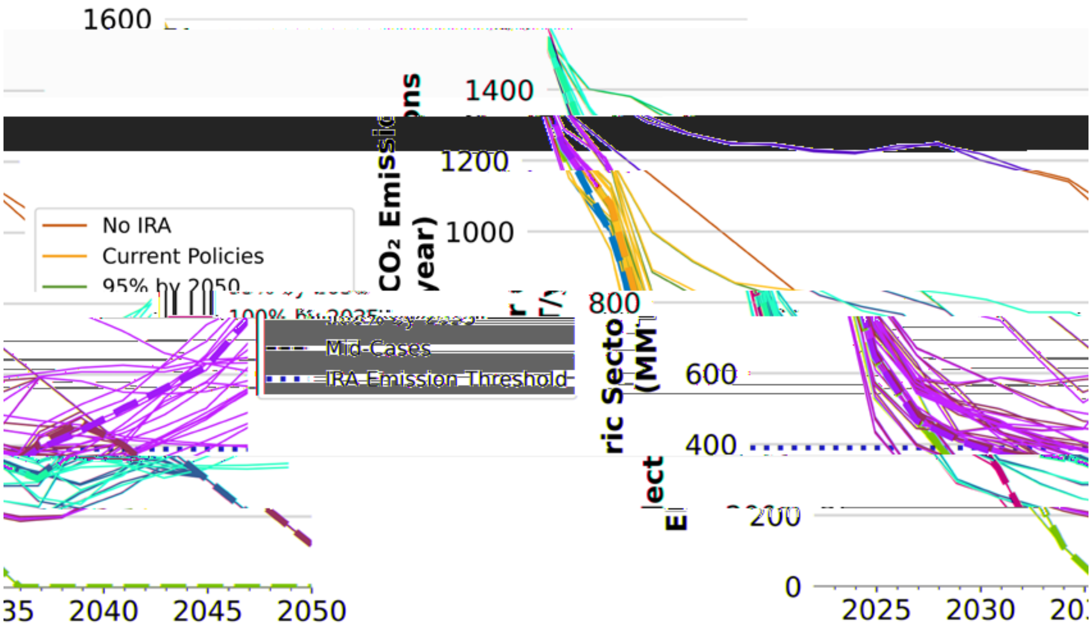

Figure 9. Electricity sector emissions over time across the Standard Scenarios. The Mid-case scenarios with the full technology set (including nascent technologies) are shown with the heavier dashed lines. MMT is million metric tons.

The incentive for captured carbon in IRA induces the retrofitting of existing fossil plants in many (but not all) of the scenarios, and its role in meeting national emissions constraints often induces further deployment in the scenarios with those constraints. Figure 10 (page 22) shows the installed capacity of CCS generators through 2050 across the suite of scenarios that include nascent technologies (CCS is categorized as a nascent technology) and Table 4 (page 22) shows the maximum deployment for different CCS technologies.

We emphasize that the future competitiveness of CCS generators is highly uncertain. That is true for any nascent technology; however, CCS warrants attention because of the increase and extension of the 45Q credit under IRA, and its resulting deployment in the Mid-case with current policies. Key uncertainties include the capital costs for retrofitting, feasibility of retrofitting specific generators, costs of capital, fuel costs, ongoing operational expenses, the costs of CO_2 transport and storage, operational performance of capture equipment, achievable capacity factors (and therefore quantity of carbon captured), and potential regulatory barriers.

Cash flow analyses we have performed external to ReEDS have aligned with our central finding that both natural gas and coal CCS retrofits have a positive net present value under our central assumptions, but can also have negative returns under plausible conditions. However, there are further improvements we expect to make to our representation of the relevant finances within ReEDS for future analyses, that may influence the timing and magnitude of CCS deployment, as well as the relative competitiveness of CCS technologies. We encourage analysts to understand these projections as an initial effort, that will likely evolve over time as our understanding and the sophistication of our representation of the technology improves.

Note also that the appearance of CCS generators in 2028 is a result of the model structure, where CCS can first become operational in that year in ReEDS (this modeling choice is meant to reflect the lead time in constructing or retrofitting a generator). In practice, we would expect CCS capacity to be initially deployed in smaller amounts and ramp up over time; however, as the constraints on the speed at which existing plants could be retrofitted are poorly understood, no such constraint is implemented in ReEDS.

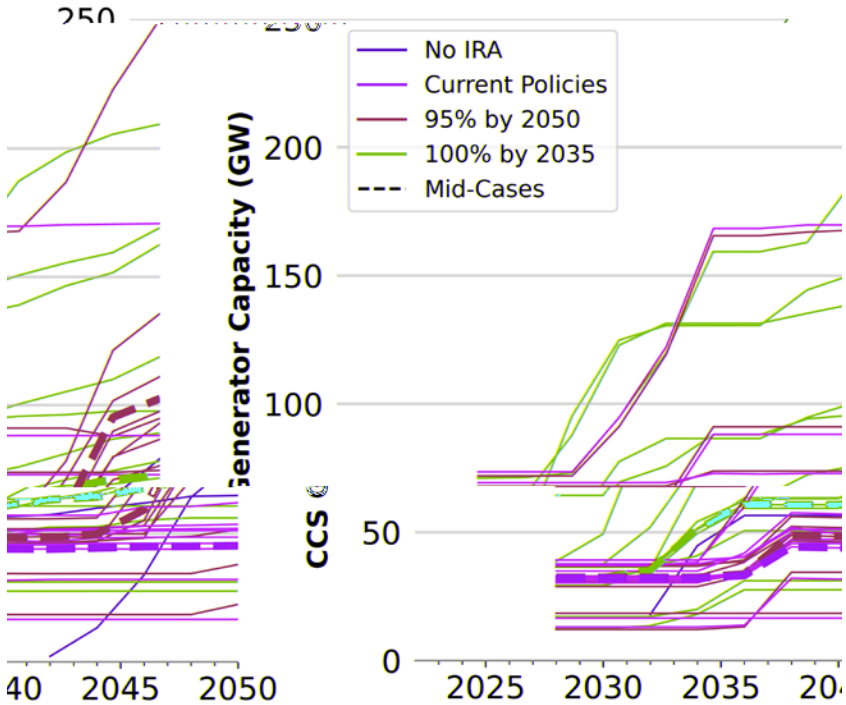

Figure 10. Deployment of CCS generator technologies across the Standard Scenarios

The Mid-case scenarios with the full technology set (including nascent technologies) are shown with the heavier dashed lines. This figure only shows CCS generator capacity, not the capacity from direct air capture.

Table 4. Maximum CCS Capacity (in gigawatts) of Each Type Deployed in 2050 across All Scenarios

Technology	Current Policies	95% by 2050	100% by 2035
NG-CC with CCS	71	147	183
Coal with CCS	100	100	20
Biopower with CCS	0	9	14
Direct air capture	0	16	97

Figure 11 shows the trends in the marginal costs[12] of two major grid services in the ReEDS model. The services are energy (providing enough generation to meet demand at each point in

[12] 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 electricity system operation or investment. Rather they reflect only the bulk generation and transmission system investment and operational costs in a given model year. Non-modeled costs, such as the costs of maintaining and expanding the distribution system, administrative costs, or program management costs, are not included.

time) and capacity (maintaining enough capacity to meet the planning reserve requirement, which is the annual maximum demand plus an additional margin that varies by region).

Marginal energy costs are influenced by the presence or absence of the PTC and ITC for renewable generators, the CO_2 reduction requirement, natural gas prices, and renewable energy technology costs. Energy costs tend to decline over time, until the 75% emissions reduction threshold specified in IRA is reached, at which point the PTC and ITC phase out and energy prices increase.

Marginal planning reserve costs grow over time as planning reserve margins tighten relative to today's levels (by the end of the 2020s, the ReEDS model has all regions exactly meeting the North American Electric Reliability Corporation-recommended planning reserve levels). The especially high planning reserve costs in a subset of the 95% by 2050 CO_2 scenarios are the cases where no nascent generator technologies are included in the model, which leads to relatively higher marginal costs for firm capacity.

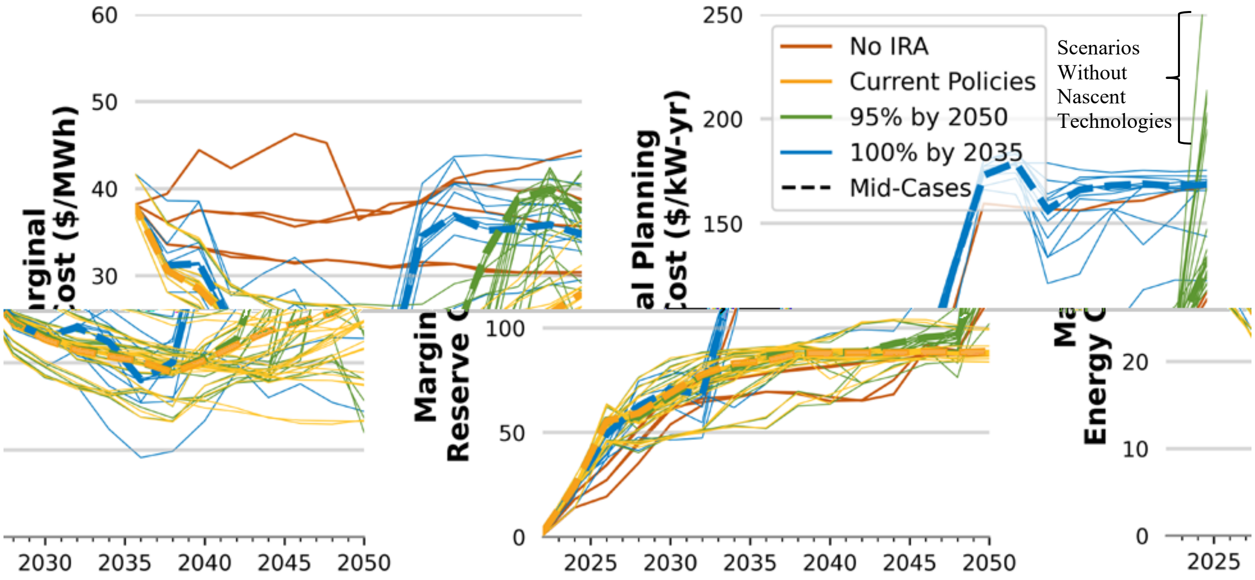

Figure 11. National annual average marginal costs for energy and capacity services. The Mid-case scenarios with the full technology set (including nascent technologies) are shown with the heavier dashed lines. Costs are in 2021 dollars.

Figure 12 shows the annual curtailed energy from wind and solar generators, in terms of both absolute amounts of curtailment as well as the percentage of total wind and solar generation. There are two groups of scenarios with exceptionally high curtailment rates: the first is the scenarios with low-cost wind and solar, all of which pass 10% curtailment in the 2030s, and then decline over time as the PTC and ITC phase out. The second are various scenarios with 95% emissions reduction in 2050 and no nascent technologies.

Figure 12. Wind and solar curtailment

The Mid-case scenarios with the full technology set (including nascent technologies) are shown with the heavier dashed lines.

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Appendix

A.1 Standard Scenarios Input Assumptions

This section contains a high-level summary of the input assumptions used in the Standard Scenarios, given in Table A-1, followed by a more detailed discussion of the inputs.

For details about the structure and assumptions in the models not mentioned here, see the documentation for ReEDS (Ho et al. 2021) and dGen (Sigrin et al. 2016). Both models are publicly available upon request,[13] 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 repository, so that any of the scenarios can be recreated.

Table A-1. Summary of Inputs to the 2022 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*	*Light electrification scenario derived by slightly modifying (reducing) the Medium Electrification* scenario from the Electrification Futures Study (Mai et al. 2018; Sun et al. 2020), described in the *Demand Growth and Flexibility* subsection below
	Low Demand Growth	AEO2022 reference growth scenario
	High Demand Growth	High electrification scenario from the Electrification Futures Study (Mai et al. 2018; Sun et al. 2020)
Fuel Prices	*Reference Natural Gas Prices*	*AEO2022 reference*[a]
	Low Natural Gas Prices	AEO2022 high oil and gas resource and technology[a]
	High Natural Gas Prices	AEO2022 low oil and gas resource and technology[a]
Electricity Generation Technology Costs	*Mid Technology Cost*	*2022 Annual Technology Baseline (ATB) moderate projections*
	Low RE and Battery Cost	2022 ATB renewable energy advanced projections
	High RE and Battery Cost	2022 ATB renewable energy conservative projections

[13] See www.nrel.gov/analysis/reeds/request-access.html and www.nrel.gov/analysis/dgen/model-access.html.

Group	Scenario Setting	Notes
	Low Nuclear and CCS Cost	2022 ATB advanced projection for coal and natural gas CCS technologies; 50% decline in small modular reactor technologies by 2030
Resource Availability	*Default Resource Constraints*	*Reference 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
Transmission Availability	*VSC[b] HVDC Transmission Not Allowed*	*VSC HVDC transmission lines disabled as investment option*
	VSC HVDC Transmission Allowed	VSC HVDC transmission lines enabled as investment option
Direct Air Capture	*Electricity-powered direct air capture of CO_2 Not Allowed*	*Electricity-powered direct air capture not available as an investment option*
	Electricity-powered direct air capture of CO_2 Allowed	Electricity-powered direct air capture available as an investment option
Policy/Regulatory Environment	*Current Law*	*Includes state, regional, and federal policies as of September 2022*
	95% by 2050	*95% net reduction in electricity sector CO_2 emissions by 2050 (relative to 2005)*
	100% by 2035	*Net zero electricity sector CO_2 emissions by 2035*
	PTC and ITC Extension	Federal PTC and ITC indefinitely extended at the values set by IRA
	No Inflation Reduction Act	Federal tax credits assumed to be at their levels prior to IRA, including scheduled phaseouts; demand assumed to be AEO2022 Reference demand

[a] Natural gas prices are based on AEO2022 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.
[b] VSC is voltage source converter.

Demand Growth and Flexibility

The Mid-case scenarios contain a demand growth trajectory that is meant to reflect light electrification induced in part by the demand-side provisions of IRA. The trajectory was created by taking the Medium Electrification scenario from the Electrification Futures Study (Mai et al. 2018) and reducing the rate of electricity growth such that the original values that were reached in 2046 are instead reached in 2050. This rate of growth was selected such that the level of electrification in 2050 was approximately halfway between the AEO2022 (EIA 2022a) Reference case and the original Medium Electrification scenario. We emphasize that this is only a simple estimate and that users should look to forthcoming work from NREL and others that develops more-sophisticated estimates of future demand growth.

The low demand growth scenario is based on the AEO2022 Reference scenario load growth. The high demand growth scenario is the High Electrification with Moderate end-use technology advancement scenario from the Electrification Futures Study (Jadun et al. 2017).

The demand trajectories have compound annual growth rates of 0.91%, 1.27%, and 1.99% from 2022 through 2050. We assume inelastic, inflexible electricity demand in all scenarios.

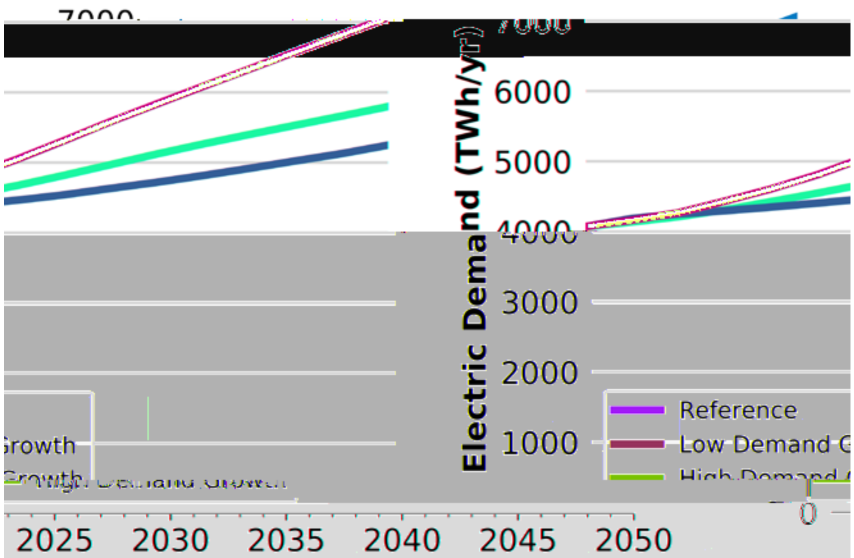

Figure A-1. Demand trajectories used in the Standard Scenarios

The Reference trajectory is used in the Mid-case set of assumptions.

The demand shapes are illustrated in Tables A-2 through A-5. The demand shapes shown are the national month-hour average demand, divided by the national annual average demand. Table A-2 shows the demand shape in 2022 in the reference demand trajectory, which is nearly identical to the demand shape in the other trajectories in 2022. The next three tables show the demand shapes in 2050. While there are broad similarities (e.g., all have summer evening peaks, and are lowest during the nighttime in the spring and fall), there are also some differences; most notably in the higher winter loads in the high-growth scenarios, driven by heating electrification. Some regions see much greater variation than is seen in these national plots, with some switching from being summer-peaking to winter-peaking systems.

Table A-2. National Month-Hour Demand Shape in 2022 in the Reference Demand Growth Trajectory

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0.97	0.92	0.88	0.86	0.86	0.86	0.89	0.95	1.02	1.06	1.06	1.05	1.04	1.03	1.01	1	0.99	0.99	1.02	1.08	1.11	1.1	1.07	1.03
2	0.94	0.89	0.86	0.84	0.83	0.84	0.86	0.92	0.99	1.03	1.03	1.03	1.02	1.01	1	0.98	0.97	0.97	0.99	1.03	1.07	1.07	1.04	1
3	0.87	0.81	0.77	0.75	0.74	0.75	0.78	0.84	0.9	0.93	0.94	0.96	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.98	1	1.01	0.99	0.94
4	0.85	0.79	0.75	0.73	0.72	0.72	0.75	0.8	0.85	0.88	0.91	0.93	0.95	0.96	0.97	0.97	0.98	0.98	0.98	0.98	0.97	0.98	0.97	0.92
5	0.93	0.85	0.8	0.77	0.75	0.75	0.77	0.82	0.87	0.92	0.97	1.02	1.06	1.09	1.11	1.13	1.15	1.16	1.16	1.14	1.11	1.1	1.08	1.02
6	1.03	0.95	0.89	0.85	0.82	0.81	0.83	0.86	0.91	0.98	1.05	1.11	1.17	1.22	1.25	1.28	1.3	1.31	1.31	1.29	1.25	1.22	1.18	1.13
7	1.16	1.07	1	0.95	0.92	0.91	0.92	0.94	0.99	1.06	1.15	1.23	1.3	1.36	1.41	1.44	1.46	1.47	1.47	1.44	1.4	1.36	1.32	1.25
8	1.1	1.01	0.95	0.9	0.88	0.87	0.89	0.93	0.97	1.03	1.1	1.17	1.24	1.29	1.34	1.38	1.4	1.41	1.41	1.38	1.34	1.3	1.26	1.19
9	0.96	0.89	0.84	0.8	0.78	0.78	0.81	0.85	0.9	0.94	0.99	1.04	1.09	1.13	1.16	1.19	1.2	1.21	1.21	1.19	1.17	1.15	1.11	1.03
10	0.85	0.79	0.76	0.73	0.72	0.73	0.76	0.82	0.87	0.9	0.93	0.95	0.97	0.98	0.99	1	1	1	1	1.01	1.03	1.02	0.98	0.92
11	0.89	0.84	0.79	0.79	0.78	0.79	0.81	0.87	0.93	0.96	0.97	0.97	0.96	0.96	0.95	0.94	0.94	0.94	0.97	1.02	1.04	1.02	0.99	0.95
12	0.96	0.9	0.86	0.83	0.82	0.83	0.85	0.9	0.96	1	1.01	1.02	1.01	1	0.99	0.98	0.98	0.98	1.02	1.09	1.1	1.09	1.07	1.02

Table A-3. National Month-Hour Demand Shape in 2050 in the Low Demand Growth Trajectory

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0.95	0.9	0.87	0.85	0.85	0.86	0.9	0.96	1.02	1.05	1.05	1.05	1.04	1.02	1	0.99	0.98	0.99	1.02	1.07	1.1	1.08	1.06	1.01
2	0.93	0.88	0.84	0.83	0.83	0.84	0.87	0.93	1	1.02	1.03	1.02	1.01	1	0.99	0.97	0.97	0.97	0.99	1.03	1.06	1.06	1.03	0.99
3	0.85	0.8	0.77	0.75	0.74	0.76	0.8	0.85	0.91	0.93	0.94	0.95	0.96	0.96	0.96	0.96	0.96	0.96	0.97	0.98	1	1	0.97	0.91
4	0.83	0.78	0.75	0.73	0.72	0.74	0.78	0.82	0.86	0.89	0.92	0.94	0.95	0.96	0.97	0.97	0.98	0.98	0.98	0.98	0.98	0.98	0.95	0.9
5	0.91	0.84	0.8	0.77	0.76	0.77	0.8	0.85	0.9	0.94	0.99	1.03	1.06	1.09	1.12	1.14	1.15	1.16	1.15	1.13	1.11	1.09	1.06	0.99
6	1.01	0.93	0.88	0.85	0.83	0.83	0.85	0.89	0.95	1.01	1.08	1.14	1.19	1.23	1.26	1.29	1.31	1.31	1.3	1.27	1.24	1.21	1.17	1.1
7	1.13	1.05	0.99	0.95	0.93	0.92	0.94	0.97	1.03	1.1	1.18	1.26	1.33	1.38	1.42	1.45	1.47	1.47	1.46	1.42	1.38	1.34	1.29	1.22
8	1.07	1	0.94	0.91	0.89	0.89	0.91	0.95	1.01	1.07	1.14	1.2	1.27	1.32	1.36	1.39	1.41	1.41	1.39	1.36	1.33	1.29	1.24	1.16
9	0.94	0.88	0.83	0.8	0.79	0.8	0.84	0.88	0.92	0.96	1.01	1.06	1.1	1.14	1.17	1.19	1.21	1.21	1.2	1.18	1.16	1.14	1.08	1.01
10	0.83	0.78	0.75	0.73	0.73	0.75	0.79	0.84	0.88	0.91	0.93	0.95	0.97	0.98	0.99	0.99	1	1	1.01	1.02	1.02	1	0.95	0.89
11	0.87	0.83	0.8	0.78	0.78	0.79	0.82	0.88	0.93	0.96	0.97	0.97	0.96	0.95	0.95	0.94	0.93	0.94	0.97	1.01	1.02	1.01	0.98	0.93
12	0.94	0.89	0.85	0.83	0.82	0.83	0.86	0.91	0.97	1	1.01	1.01	1.01	1	0.99	0.98	0.97	0.99	1.03	1.08	1.09	1.08	1.05	1.01

Table A-4. National Month-Hour Demand Shape in 2050 in the Reference Demand Growth Trajectory

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0.94	0.87	0.82	0.79	0.78	0.78	0.81	0.87	0.96	1.02	1.03	1.03	1.03	1.04	1.04	1.04	1.04	1.08	1.16	1.25	1.24	1.15	1.09	1.02
2	0.91	0.84	0.79	0.76	0.76	0.76	0.78	0.85	0.93	0.99	1	1	1	1.01	1.02	1.01	1.02	1.05	1.11	1.18	1.19	1.12	1.06	0.99
3	0.85	0.78	0.72	0.69	0.68	0.68	0.7	0.77	0.85	0.9	0.93	0.95	0.97	1	1.02	1.02	1.04	1.08	1.13	1.17	1.15	1.08	1.02	0.94
4	0.83	0.76	0.7	0.67	0.65	0.66	0.68	0.74	0.8	0.86	0.9	0.92	0.95	0.99	1.02	1.03	1.05	1.09	1.14	1.16	1.12	1.06	1.01	0.93
5	0.9	0.81	0.74	0.7	0.68	0.68	0.7	0.75	0.81	0.89	0.95	1	1.05	1.1	1.15	1.17	1.2	1.26	1.31	1.33	1.25	1.15	1.09	1
6	0.98	0.89	0.81	0.76	0.74	0.73	0.74	0.78	0.85	0.94	1.02	1.08	1.15	1.21	1.27	1.3	1.33	1.39	1.44	1.45	1.37	1.25	1.18	1.1
7	1.09	0.99	0.9	0.85	0.82	0.81	0.81	0.85	0.91	1.01	1.1	1.18	1.26	1.34	1.41	1.44	1.47	1.52	1.57	1.57	1.49	1.37	1.29	1.2
8	1.03	0.94	0.86	0.81	0.78	0.78	0.79	0.84	0.9	0.99	1.06	1.13	1.21	1.29	1.35	1.38	1.42	1.48	1.53	1.53	1.45	1.33	1.24	1.14
9	0.91	0.83	0.77	0.73	0.7	0.7	0.72	0.78	0.84	0.9	0.96	1.01	1.07	1.13	1.18	1.21	1.24	1.29	1.33	1.34	1.28	1.19	1.11	1.01
10	0.83	0.76	0.7	0.67	0.66	0.66	0.69	0.75	0.82	0.88	0.91	0.94	0.97	1.01	1.04	1.05	1.07	1.11	1.16	1.2	1.18	1.09	1	0.92
11	0.87	0.8	0.74	0.72	0.71	0.71	0.73	0.79	0.87	0.93	0.94	0.95	0.96	0.97	0.99	0.99	1	1.04	1.12	1.2	1.18	1.08	1.02	0.95
12	0.94	0.86	0.8	0.76	0.75	0.75	0.77	0.82	0.91	0.97	0.99	1	1	1.02	1.03	1.03	1.04	1.08	1.17	1.27	1.25	1.16	1.1	1.02

Table A-5. National Month-Hour Demand Shape in 2050 in the High Demand Growth Trajectory

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0.94	0.87	0.81	0.78	0.77	0.78	0.8	0.86	0.97	1.04	1.04	1.04	1.04	1.05	1.07	1.06	1.07	1.13	1.22	1.33	1.3	1.19	1.11	1.02
2	0.91	0.84	0.79	0.76	0.75	0.75	0.77	0.84	0.94	1.01	1.01	1.01	1.01	1.02	1.04	1.03	1.04	1.09	1.17	1.25	1.24	1.15	1.07	0.99
3	0.85	0.77	0.72	0.68	0.67	0.67	0.7	0.76	0.85	0.91	0.93	0.95	0.97	1.01	1.04	1.04	1.06	1.12	1.19	1.24	1.2	1.1	1.03	0.94
4	0.82	0.75	0.69	0.66	0.65	0.65	0.67	0.73	0.8	0.86	0.9	0.92	0.96	1	1.04	1.05	1.07	1.13	1.19	1.22	1.17	1.08	1.02	0.92
5	0.88	0.79	0.72	0.68	0.66	0.66	0.68	0.73	0.8	0.88	0.94	0.98	1.04	1.1	1.15	1.17	1.21	1.27	1.35	1.37	1.28	1.15	1.07	0.98
6	0.95	0.86	0.78	0.73	0.71	0.71	0.71	0.76	0.83	0.92	1	1.06	1.12	1.2	1.26	1.28	1.32	1.39	1.46	1.48	1.38	1.23	1.15	1.06
7	1.04	0.94	0.86	0.8	0.78	0.77	0.77	0.81	0.88	0.98	1.07	1.14	1.23	1.31	1.39	1.41	1.45	1.51	1.57	1.58	1.49	1.34	1.25	1.16
8	0.99	0.9	0.82	0.77	0.75	0.75	0.76	0.81	0.87	0.96	1.04	1.11	1.18	1.26	1.33	1.36	1.4	1.47	1.54	1.55	1.45	1.3	1.21	1.1
9	0.89	0.81	0.74	0.7	0.68	0.68	0.7	0.75	0.81	0.88	0.94	1	1.05	1.12	1.18	1.2	1.23	1.29	1.36	1.37	1.3	1.18	1.09	0.99
10	0.83	0.75	0.7	0.66	0.65	0.65	0.67	0.74	0.81	0.87	0.91	0.93	0.97	1.01	1.05	1.07	1.09	1.14	1.21	1.26	1.22	1.1	1.01	0.92
11	0.86	0.8	0.73	0.71	0.7	0.7	0.72	0.78	0.87	0.94	0.95	0.95	0.96	0.99	1.01	1.01	1.03	1.08	1.18	1.28	1.23	1.11	1.04	0.95
12	0.93	0.86	0.79	0.76	0.74	0.74	0.76	0.82	0.92	0.99	1	1	1.01	1.03	1.05	1.06	1.07	1.13	1.23	1.34	1.31	1.19	1.12	1.03

Fuel Prices

Natural gas input price points are based on the trajectories from AEO2022 (EIA 2022a). The input price points are drawn from the AEO2022 Reference scenario, the AEO2022 Low Oil and Gas Supply scenario, and the AEO2022 High Oil and Gas Supply scenario (EIA 2022a). 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 in the electric sector. 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.

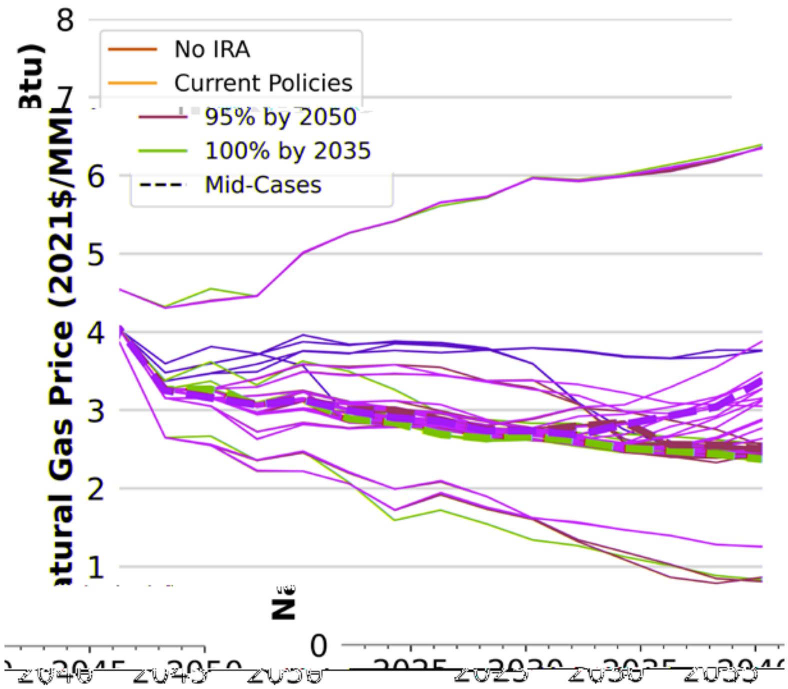

Figure A-2. National average natural gas price outputs from the suite of scenarios

The coal and uranium price trajectories are from the AEO2022 Reference scenario and are shown in Figure A-3. Both coal and uranium prices are assumed to be fully inelastic. Coal prices vary by census region (using the AEO2022 census region projections. Figure A-3 shows the maximum and the minimum coal prices, across the census regions. Uranium prices are the same across the United States.

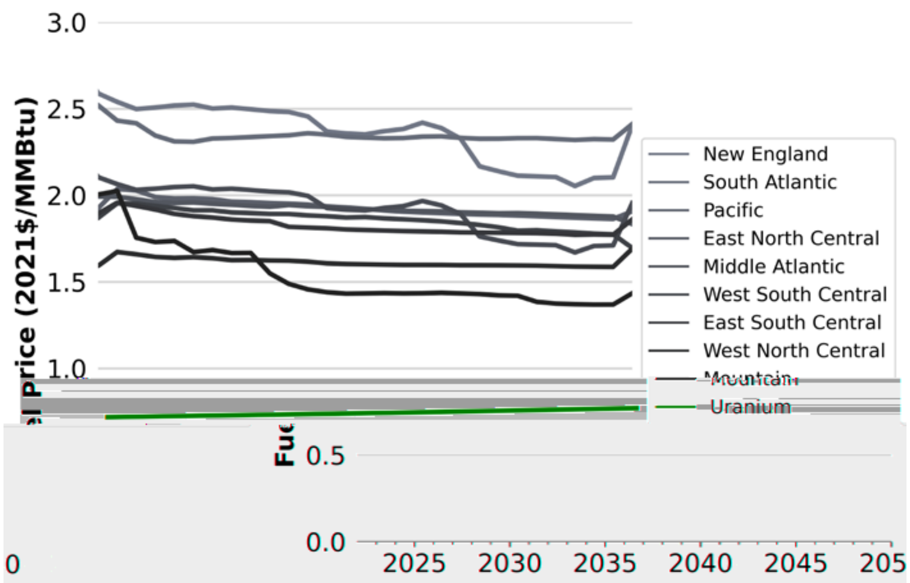

Figure A-3. Input coal and uranium fuel prices used in the Standard Scenarios

Uranium prices are the same across the United States. Coal prices vary by census region, and as listed in descending order of average price in the legend in this figure.

Renewable fuel 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 (e.g., hydrogen, biodiesel, ethanol, or green methane) that is assumed to cost $20/MMBtu in 2022 dollars at any point in time, in these scenarios. The additional electric load from the production of a renewably derived fuel is not incorporated into these scenarios. The actual delivered cost that a renewably derived fuel could achieve is, like all future costs, highly uncertain. Current delivered prices for fuels like hydrogen are significantly higher than assumed here (e.g., the cost of delivering hydrogen via liquid tankers, not including production costs, was estimated at $68/MMBtu in 2021 dollars in 2020 (DOE 2020), although such delivery costs would be expected to decrease significantly if pipeline infrastructure were built). NREL's Annual Technology Baseline (ATB) estimates that the delivered price of hydrogen could reach $56/MMBtu (in 2021 dollars) when using high temperature electrolysis in futures with high volume markets—although the ATB estimates do not include the incentives for hydrogen production in IRA, which can be as high as $22/MMBtu.

Technology Cost and Performance

Technology cost and performance assumptions are taken from the 2022 ATB (NREL 2022). 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 renewable energy (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 (for these scenarios, RE technologies include all solar, geothermal, hydropower, and wind generators). Scenarios with low CCS costs use the advanced coal and natural gas CCS technology projections from the ATB. Low nuclear costs are not available in the ATB, so to create a low nuclear cost projection, we assume nuclear capital and fixed operation 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).

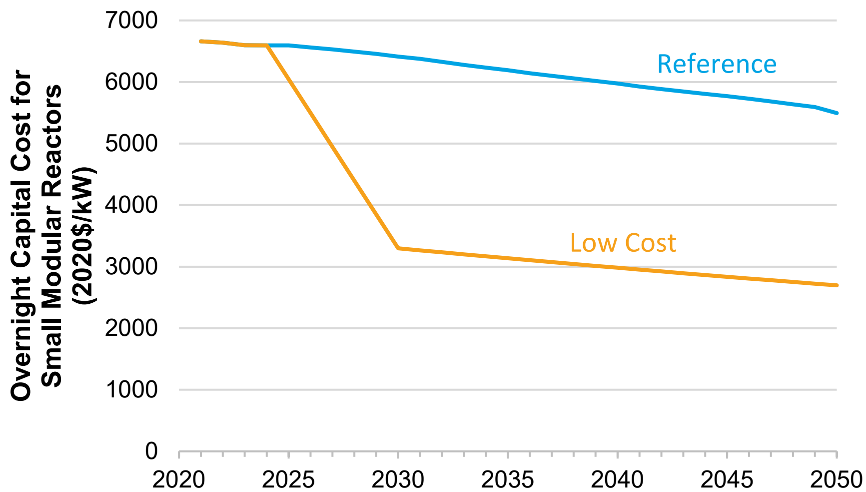

Figure A-4. Capital cost projections for small modular reactor technologies

ReEDS allows coal and natural gas generators to be retrofitted into their CCS equivalents. The ATB does not contain explicit estimates of CCS retrofit costs. Instead, the cost of retrofitting a generator with a CCS system is assumed to be the difference between the CAPEX of a greenfield CCS and non-CCS version of the generator in that scenario, plus a 20% adder (shown in Figure A-5). As with all technology costs, the future n^{th} plant retrofit costs are highly uncertain, and will likely have greater diversity than we assume, given that the necessary expenses may vary meaningfully by generator. Note that the first year the ReEDS model is enabled to have fossil-CCS become operational is 2028, reflecting construction lead times.

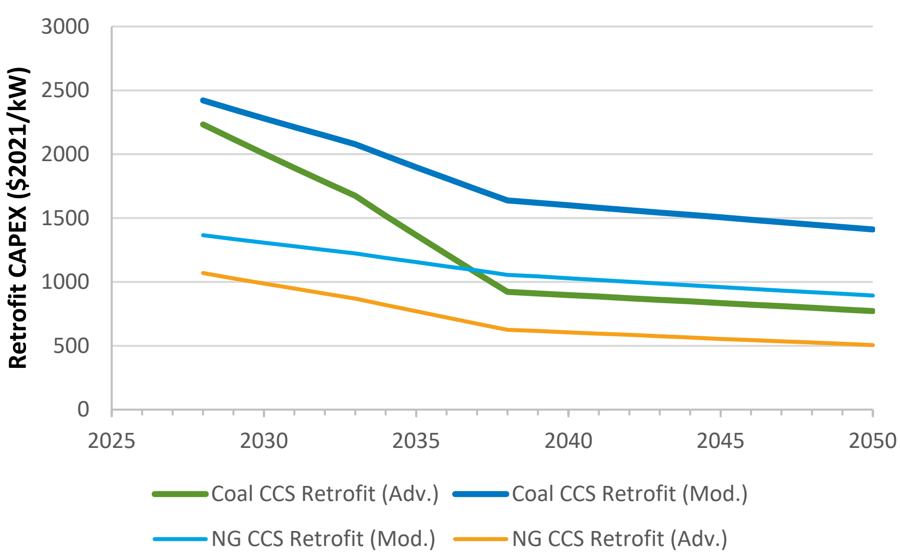

Figure A-5. Capital cost projections for fossil-CCS retrofits

Direct air capture cost and performance values are the conservative assumptions from Fasihi, Efimova, and Breyer (2019). 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). Natural gas turbines can be upgraded to RE-CTs for 20% the cost of a new gas turbine or be built new at a cost 3% higher than natural gas turbines. Heat rates and operation 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-6 and A-7. These lifetimes represent that maximum lifetimes generators are allowed to remain online in the model. The model will retire generators before these lifetimes if their value to the system is less than 50% of their ongoing fixed maintenance and operational costs (50% is assumed, instead of 100%, to roughly approximate the friction of plant retirements, as retirement decisions in practice are often not strictly economic decisions). If a retirement date has been announced for a generator, ReEDS will retire the capacity retiring that generator at that date or earlier.

Table A-6. 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)
CSP	30	SunShot Vision (DOE 2012)
Geothermal	30	GeoVision (DOE 2019)
Hydropower	100	Hydropower Vision (DOE 2016)
Biopower	50	2021 National Energy Modeling System plant database (EIA 2021)
Battery	15	Cole, Frazier, and Augustine (2021)
RE-CT	50	Matching natural gas combustion turbines

Table A-7. 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 resource available to 2.03 TW, compared with 6.64 terawatts (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 from 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).

Transmission Expansion

All scenarios except the high and low transmission scenarios allow the current transmission network to be expanded. Expansion can only occur in regions that are currently connected by transmission.

The high transmission availability sensitivity allows new high voltage direct current (HVDC) transmission capacity to be built between any pair of regions that are connected by existing transmission. HVDC transmission is assumed to have a loss rate of 0.5%/100 miles (as compared to 1%/100 miles for AC) and to use voltage source converters (VSC) with a 1% loss rate for AC/DC conversion. For additional descriptions of how the transmission networks are modeled, see Section B.2 in the appendix of (Denholm et al. 2022).

Rooftop PV Adoption

The Standard Scenarios rely on the dGen model to provide estimates of rooftop PV deployment over time. dGen produces projections for rooftop PV deployment over time using marginal electricity costs from ReEDS. Only a subset of the Standard Scenarios have corresponding dGen runs (the Mid-case, Low RE Cost, High RE Cost, and No IRA scenarios). 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 reported here. See Section 2.3 for a discussion of the interpretation of IRA's provisions for distributed generation.

A.2 Changes from the 2021 Edition

Since last year's Standard Scenarios report (Cole et al. 2021), we have made the key modeling changes in the ReEDS model that are summarized in Table A-8.

Table A-8. Key Differences in Model Inputs and Treatments for ReEDS Model Versions. The 2021 version (Ho et al. 2021) was used in the 2021 Standard Scenarios report (Cole et al. 2021), and the 2022 version is used for this report.

Inputs and Treatments	**2021 Version**	**2022 Version**
Fuel prices	AEO2021	AEO2022
Demand growth	AEO2021	Electrification Futures Study, AEO2022
Demand shape	In most scenarios, demand shape would remain essentially constant going forward in time.	In most scenarios, demand shape changes slightly to reflect light electrification.
Generator technology cost, performance, and financing	2021 ATB[a]	2022 ATBa
Existing generator plant database	AEO2021	AEO2022
Incentive safe harbor	Safe harbor is implicitly set at the construction time of each generator.	Safe harbor is explicitly represented for most technologies. Generators select the most valuable incentive available within their safe harbor window.
Federal policy	Representations of PTC, ITC, and 45Q as of June 2021	Representations of the PTC, ITC, and carbon capture credits in IRA, explained in Section 2.3
Supply chain capital cost adjustment	No adjustment	Based on empirical observations in proprietary market reports, a technology-neutral multiplier of 1.1 was applied to the CAPEX of all generators in 2022, linearly decreasing to 1.0 over 5 years.
Transmission investment	ReEDS could only endogenously invest in transmission starting in 2026. Only announced projects are built before then.	ReEDS can endogenously invest in up to 1.4 TW-mi per year from 2023 through 2027, and investment is unrestricted after that.
Rooftop PV adoption scenarios	The same scenarios as were used in the 2020 Standard Scenarios (W. Cole, Corcoran, et al. 2020)	Updated scenarios based on an extension of the ITC under IRA, as described in Section 2.3
Retail cost adder for electricity-consuming resources	Not included	A cost adder of $29.4/MWh (2021$) is applied to direct air capture costs to represent the costs associated with additional electricity consumption that are not natively in the ReEDS model. The adder amount is derived from the difference between wholesale electricity costs and industrial retail rates.

Inputs and Treatments	2021 Version	2022 Version
Voluntary procurement of clean energy credits	Not included	Voluntary (e.g., corporate) demand for clean energy credits starts at 5.5% of retail sales and grows at 0.16%/year. The rates are based on observed trends (Heeter, O'Shaughnessy, and Burd 2021).
PV-battery hybrid technology	Included with an inverter loading ratio of 1.3- and a 4.0-hour battery sized at half the PV inverter capacity	Not available by default; only included in a sensitivity case due to lack of inputs for the Reduced RE Resource sensitivity. When enabled, multiple configurations are available for investment.
Electricity-powered direct air capture	Turned on by default in scenarios unless otherwise specified	Not available by default in scenarios unless otherwise specified
State policies	Policies as of June 2021	Policies as of September 2022
Emissions	Only CO_2 emissions from direct combustion are reported.	Emissions reported in online data are expanded to include CH_4, N_2O, SO_2, and NOx. See Section A.3 (Emission Factors by Fuel, page 38).

[a] The default cost recovery periods are 20 years in ReEDS, while it is 30 years in the ATB.

A.3 Metric Definitions

This section defines the metrics that are available for download through NREL's Scenario Viewer (https://scenarioviewer.nrel.gov/).

Metric Family: nameplate capacity by technology
Metric Name: *technology_MW*
Units: MW

These metrics report the total nameplate capacity within a region for each of the specified technologies. Behind-the-meter PV is reported as the AC inverter capacity—it is not adjusted to a busbar equivalent capacity, unlike generation from the same technology. The capacities of wind and solar generation are reported at their original nameplate capacities when they were installed (i.e., their reported capacity is not reduced over time by degradation). Electric battery capacities are reported by their duration (e.g., *battery_2_MW* is the MW capacity of 2-hour electric battery storage).

The nameplate capacity of Direct Air Capture (DAC) devices are reported as *dac_MW*. It should be noted that DAC consumes electricity, it does not generate it.

Metric Family: generation by technology
Metric Name: *technology_MWh*
Units: MWh_{busbar} / year

These metrics report the total generation within either a state or the nation for the specified technology. These generation values do not include curtailed energy. Generation from behind-the-meter PV, which is assumed to occur at the point of end use, is reported as an equivalent amount of busbar generation. Storage generation is reported as the total discharge from a given technology over the course of the year (as opposed to the net effect, which would be negative due to losses). Electric battery generation is reported by its duration (e.g., *battery_2_MWh* is the total MWh of electric discharge from 2-hour electric batteries storage).

Metric Family: total emissions by region
Metric Name: *co2_c_mt, co2e_c_mt, ch4_c_mt, n2o_c_mt, so2_c_mt, nox_c_mt, co2_p_mt, co2e_p_mt, ch4_p_mt, n2o_p_mt, dac_co2_capture_mt*
Units: metric tons

This family of metrics reports the total emissions from all generation within a region, in metric tons. No adjustment is made for imported or exported electricity. Start-up and shut-down emissions are not included. The capture from CCS generators and direct air capture technologies is incorporated into the CO_2 and CO_2e metrics (i.e., the CO_2 metrics are net of carbon capture). For users interested in net emissions from generators alone, the *dac_co2_capture_mt* metric can be used to remove the contribution of direct air capture from the metric of interest.

The emissions are reported by emission type (CO_2, CO_2e, CH_4, N_2O, SO_2, and NO_x) and whether the emissions are from direct combustion or precombustion activities (which include fuel extract, processing, and transport). "*_c*" indicates emissions from direct combustion, whereas "*_p*" indicates emissions from precombustion activities. The CO_2e metrics report the combined CO_2 equivalence of CO_2, CH_4, and N_2O, using global warming potentials from IPCC AR6.

Metric Family: average emission rates of in-region generation
Metric Name: *co2_c_kg_per_mwh, co2e_c_kg_per_mwh, ch4_c_g_per_mwh, n2o_c_g_per_mwh, so2_c_g_per_mwh, nox_c_g_per_mwh, co2_p_kg_per_mwh, ch4_p_g_per_mwh, n2o_p_g_per_mwh*
Units: $kg/MWh_{generation}$ for CO_2 and CO_2e, $g/MWh_{generation}$ for all others

This family of metrics reports the average emission rate from all generation within a region. CO_2 and CO_2e metrics are reported in kg per MWh, whereas the others are reported in grams per MWh. No adjustment is made for imported or exported electricity. Start-up and shut-down emissions are not included. The capture from CCS generators and direct air capture technologies is incorporated into the CO_2 and CO_2e metrics (i.e., the CO_2 metrics are net of carbon capture). For users interested in net emissions from generators alone, the *dac_co2_capture_mt* metric can be used to remove the contribution of direct air capture from the metric of interest.

The emissions are reported by emission type (CO_2, CO_2e, CH_4, N_2O, SO_2, and NO_x) and whether the emissions are from direct combustion or precombustion activities (which include fuel extract, processing, and transport). "*_c*" indicates emissions from direct combustion, whereas "*_p*" indicates emissions from precombustion activities. The CO_2e metrics report the combined CO_2 equivalence of CO_2, CH_4, and N_2O, using global warming potentials from IPCC AR6.

A.4 Emission Factors by Fuel

Previous editions of the Standard Scenarios only reported CO_2 emissions from direct combustion of fuels for electricity generation. In the 2022 edition, the emissions reported and available through the online data downloader have been expanded. The emissions metrics are calculated using the fuel-specific emissions factors given in this section. The resulting emissions per megawatt-hour of electric generation is a function of the generator's heat rate (i.e., the rate at which fuel is converted into electricity), which can vary by generator. Heat rates for newly built generators generally follow the projections in NREL's ATB. Heat rates for existing generators draw from EIA data. The input data and logic driving the overall mixture of heat rates in ReEDS can be viewed via the publicly available ReEDS repository.

Emissions factors for CO_2, CH_4, and N_2O are national averages. SO_2 and NO_x emissions factors for non-CCS gas, non-CCS coal, and oil are the average of state-level averages for those fuels from 2019 and 2020 eGRID data. The remaining SO_2 and NO_x emissions factors are national averages drawn from the ATB or prior ReEDS assumptions. There are no precombustion values for SO_2 or NO_x. All reported emissions are derived from historical emissions intensities, which neglect how emissions may change in the future (e.g., increases in emissions intensities from more variable generator operations or decreases in emissions intensities from improvements in control technologies).

The precombustion emission factors include fuel extraction, processing, and transport, including fugitive emissions. The precombustion emissions for natural gas are drawn from (Littlefield et al. 2019). Power plants are assumed to avoid distribution losses, which results in a fugitive methane emissions rate of 1.08%.[14]

Emissions from ongoing, non-combustion activities (e.g., the emissions induced by operation and maintenance activities) are not included in the emissions metrics. Emissions from commissioning or decommissioning generators or other physical infrastructure are also not included.

Bioenergy with CCS is assumed to have a net combustion rate of negative 60.0 kg of CO_2 per MMBtu of fuel (where the CO_2 removal from feedstock growth and subsequent capture post-combustion is combined into a single factor). The bioenergy with CCS values for precombustion activities take the same values as the biomass category. Natural gas and coal generators with carbon capture are assumed to have a 90% reduction in their CO_2 from direct combustion.

Sources indicated in Table A-9 are:

- US LCI: *U.S. Life Cycle Inventory Database* (NREL 2021)
- ReEDS 2021: *Regional Energy Deployment System (ReEDS) Model Documentation: Version 2020* (Ho et al. 2021)
- EPA 2016: *Greenhouse Gas Inventory Guidance: Direct Emissions from Stationary Combustion Sources* (United States Environmental Protection Agency 2016)
- ATB 2021: *Annual Technology Baseline 2021* (NREL 2021)
- CARB 11-307: *Assessment of the Emissions and Energy Impacts of Biomass and Biogas Use in California* (Carreras-Sospedra et al. 2015).
- NETL 2019: *Life Cycle Analysis of Natural Gas Extraction and Power Generation* (Littlefield et al. 2019)

[14] Assuming power plants avoid distribution losses was explicitly stated by Skone et al. in a predecessor publication (Skone et al. 2014).

- eGRID: *eGRID2019 Data File*, *eGRID2020 Data File* (EIA 2022b).

Table A-9. Emission Factors by Fuel

Fuel	Type	Emission	Emission Factor	Units	Source
Coal	Precombustion	CO_2	2.94	kg/MMBtu	USLCI: Bituminous Coal at power plant
		CH_4	208.26	g/MMBtu	USLCI: Bituminous Coal at power plant
		N_2O	0.05	g/MMBtu	USLCI: Bituminous Coal at power plant
	Combustion	CO_2	95.52	kg/MMBtu	ReEDS 2021
		CH_4	11.00	g/MMBtu	EPA 2016: Table A-3, Coal and Coke, Mixed (Electric Power Sector)
		N_2O	1.60	g/MMBtu	EPA 2016: Table A-3, Coal and Coke, Mixed (Electric Power Sector)
		SO_2	state	g/MMBtu	eGRID 2019 & 2020
		NOx	state	g/MMBtu	eGRID 2019 & 2020
Coal CCS	Precombustion	CO_2	2.94	kg/MMBtu	USLCI: Bituminous Coal at power plant
		CH_4	208.26	g/MMBtu	USLCI: Bituminous Coal at power plant
		N_2O	0.05	g/MMBtu	USLCI: Bituminous Coal at power plant
	Combustion	CO_2	9.55	kg/MMBtu	ReEDS 2021
		CH_4	11.00	g/MMBtu	EPA 2016: Table A-3, Coal and Coke, Mixed (Electric Power Sector)
		N_2O	1.60	g/MMBtu	EPA 2016: Table A-3, Coal and Coke, Mixed (Electric Power Sector)
		SO_2	0.0	g/MMBtu	ATB 2021
		NOx	35.0	g/MMBtu	ATB 2021
Natural Gas	Precombustion	CO_2	6.27	kg/MMBtu	USLCI: Natural Gas at power plant
		CH_4	277.45	g/MMBtu	NETL 2019
		N_2O	0.02	g/MMBtu	USLCI: Natural Gas at power plant
	Combustion	CO_2	53.06	kg/MMBtu	ReEDS 2021
		CH_4	1.00	g/MMBtu	EPA 2016: Table A-3, Natural Gas
		N_2O	0.10	g/MMBtu	EPA 2016: Table A-3, Natural Gas
		SO_2	state	g/MMBtu	eGRID 2019 & 2020
		NOx	state	g/MMBtu	eGRID 2019 & 2020
	Precombustion	CO_2	6.27	kg/MMBtu	USLCI: Natural Gas at power plant

Fuel	Type	Emission	Emission Factor	Units	Source
Natural Gas CCS		CH_4	277.45	g/MMBtu	NETL 2019
		N_2O	0.02	g/MMBtu	USLCI: Natural Gas at power plant
	Combustion	CO_2	5.31	kg/MMBtu	ReEDS 2021
		CH_4	1.00	g/MMBtu	EPA 2016: Table A-3, Natural Gas
		N_2O	0.10	g/MMBtu	EPA 2016: Table A-3, Natural Gas
		SO_2	0.0	g/MMBtu	ATB 2021
		NOx	1.5	g/MMBtu	ATB 2021
Residual Fuel Oil	Precombustion	CO_2	9.91	kg/MMBtu	USLCI at power plant
		CH_4	153.45	g/MMBtu	USLCI at power plant
		N_2O	0.17	g/MMBtu	USLCI at power plant
	Combustion	CO_2	75.10	kg/MMBtu	ReEDS 2021
		CH_4	3.00	g/MMBtu	EPA 2016: Table A-3, Petroleum Products, Residual Fuel Oil No. 6
		N_2O	0.60	g/MMBtu	EPA 2016: Table A-3, Petroleum Products, Residual Fuel Oil No. 6
		SO_2	state	g/MMBtu	eGRID 2020
		NOx	state	g/MMBtu	eGRID 2020
Uranium	Precombustion	CO_2	0.84	kg/MMBtu	USLCI: Uranium at power plant
		CH_4	2.10	g/MMBtu	USLCI: Uranium at power plant
		N_2O	0.02	g/MMBtu	USLCI: Uranium at power plant
	Combustion	CO_2	0.00	kg/MMBtu	ReEDS 2021
		CH_4	0.00	g/MMBtu	-
		N_2O	0.00	g/MMBtu	-
		SO_2	0.00	g/MMBtu	-
		NOx	0.00	g/MMBtu	-
Biomass	Precombustion	CO_2	2.46	kg/MMBtu	CARB 11-307: Table 15
		CH_4	2.94	g/MMBtu	CARB 11-307: Table 15
		N_2O	0.01	g/MMBtu	CARB 11-307: Table 15
	Combustion	CO_2	0.00	kg/MMBtu	ReEDS 2021
		CH_4	0.00	g/MMBtu	-
		N_2O	0.00	g/MMBtu	-
		SO_2	36.00	g/MMBtu	ATB 2021
		NOx	0.00	g/MMBtu	ATB 2021
RE Fuel	Precombustion	CO_2	0.00	kg/MMBtu	-

Fuel	Type	Emission	Emission Factor	Units	Source
		CH_4	0.00	g/MMBtu	-
		N_2O	0.00	g/MMBtu	-
	Combustion	CO_2	0.00	kg/MMBtu	ReEDS 2021
		CH_4	0.00	g/MMBtu	-
		N_2O	0.00	g/MMBtu	-
		SO_2	0.00	g/MMBtu	ReEDS 2021
		NOx	70.00	g/MMBtu	ReEDS 2021

A.5 Generation and Capacity Figures for All Scenarios

The figures in this section show the generation and capacity for all scenarios, grouped by the 14 sensitivities:

- Mid-case (Figure A-6, page 44)
- Low Renewable Energy and Battery Costs (Figure A-7, page 45)
- High Renewable Energy and Battery Costs (Figure A-8, page 46)
- Low Nuclear and Carbon Capture Costs (Figure A-9, page 47)
- High Transmission Availability (Figure A-10, page 48)
- Reduced Renewable Energy Resource (Figure A-11, page 49)
- Hybrid PV-batteries (Figure A-12, page 50)
- Electricity-powered Direct Air Capture (Figure A-13, page 51)
- Low Demand Growth (Figure A-14, page 52)
- High Demand Growth (Figure A-15, page 53)
- Low Natural Gas Prices (Figure A-16, page 54)
- High Natural Gas Prices (Figure A-17, page 55)
- PTC and ITC Extension (Figure A-18, page 56)
- No Inflation Reduction Act (Figure A-19, page 57).

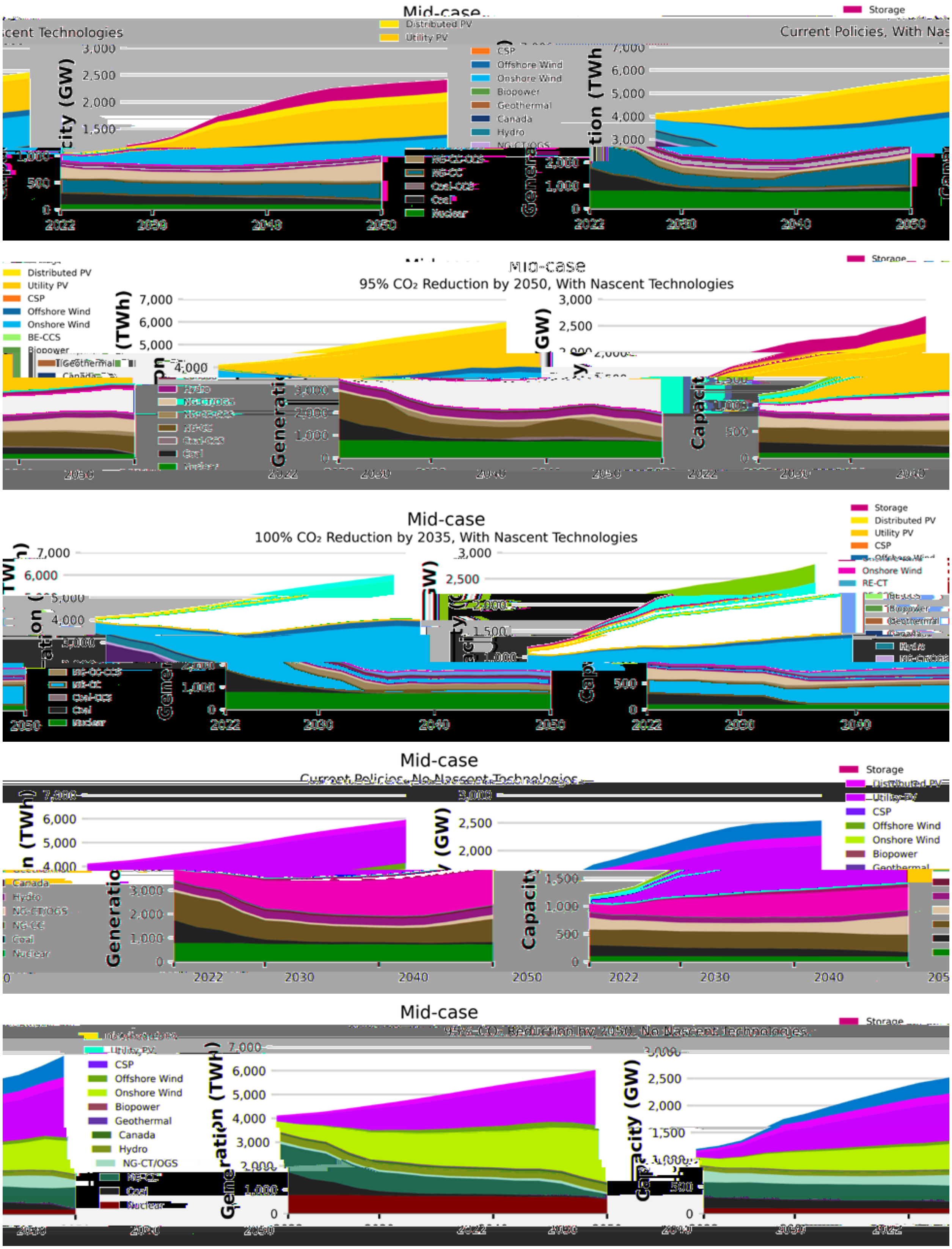

Figure A-6. Mid-case: Generation and capacity

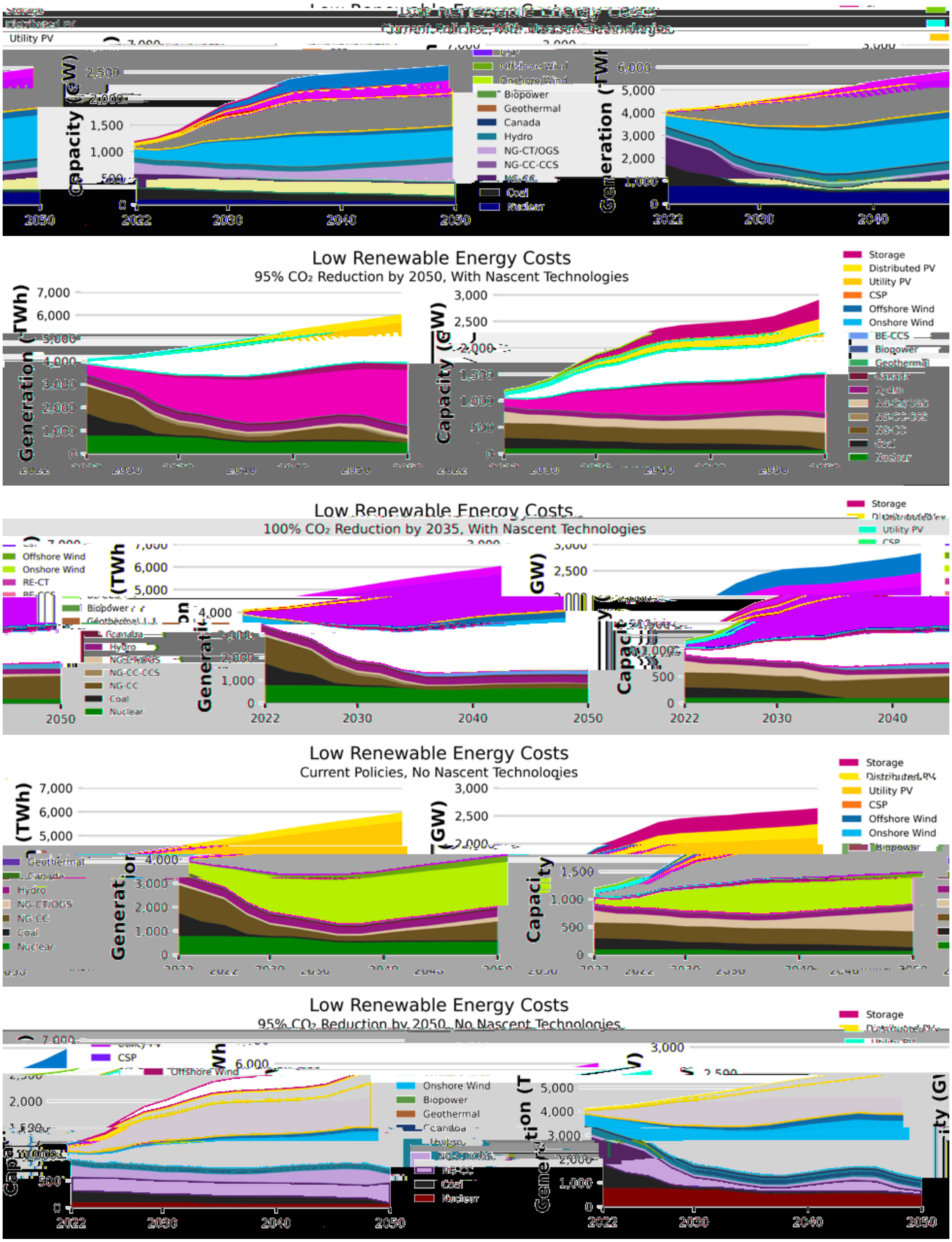

Figure A-7. Low Renewable Energy and Battery Costs sensitivity: Generation and capacity

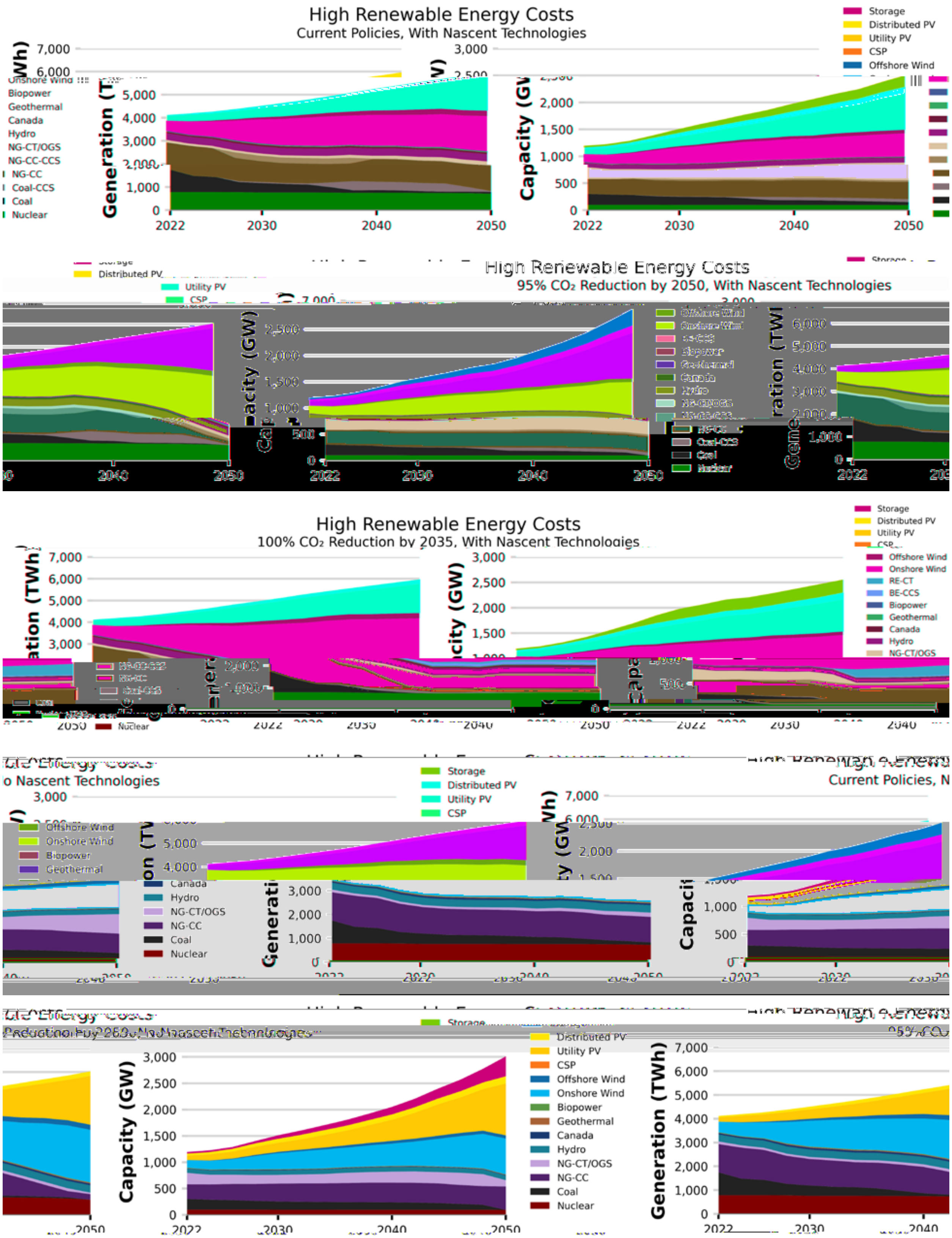

Figure A-8. High Renewable Energy and Battery Cost sensitivity: Generation and capacity

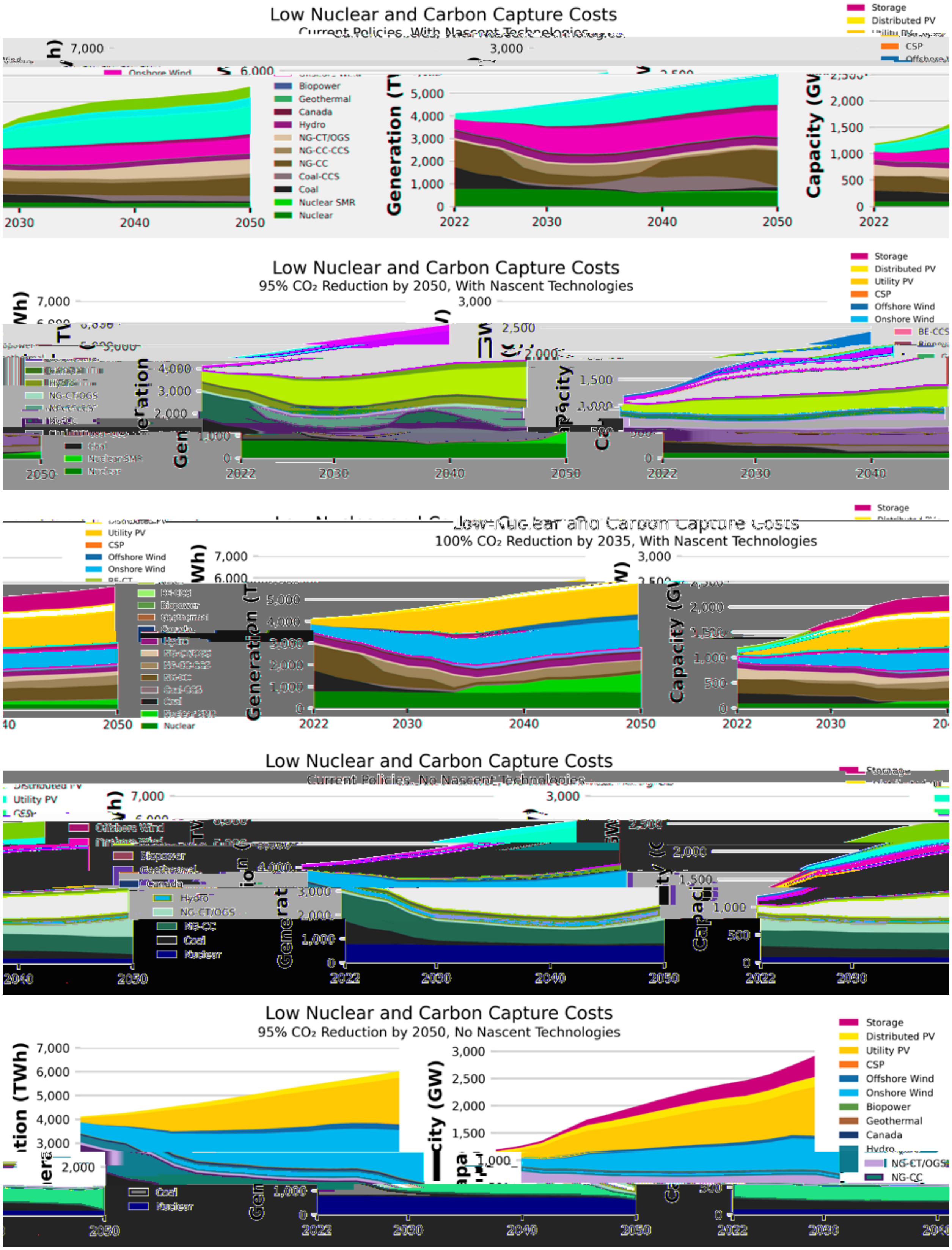

Figure A-9. Low Nuclear and Carbon Capture Costs sensitivity: Generation and capacity

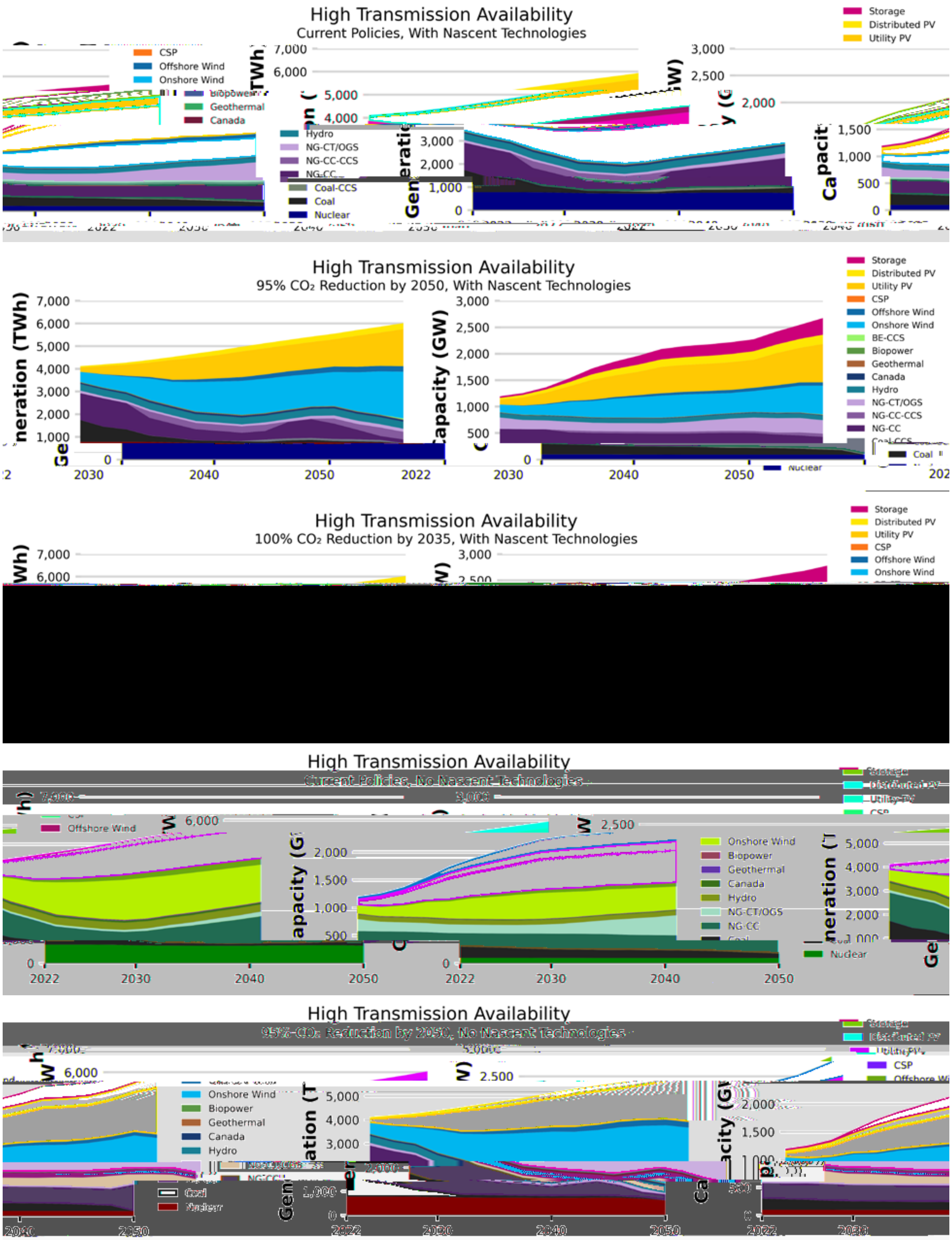

Figure A-10. High Transmission Availability sensitivity: Generation and capacity

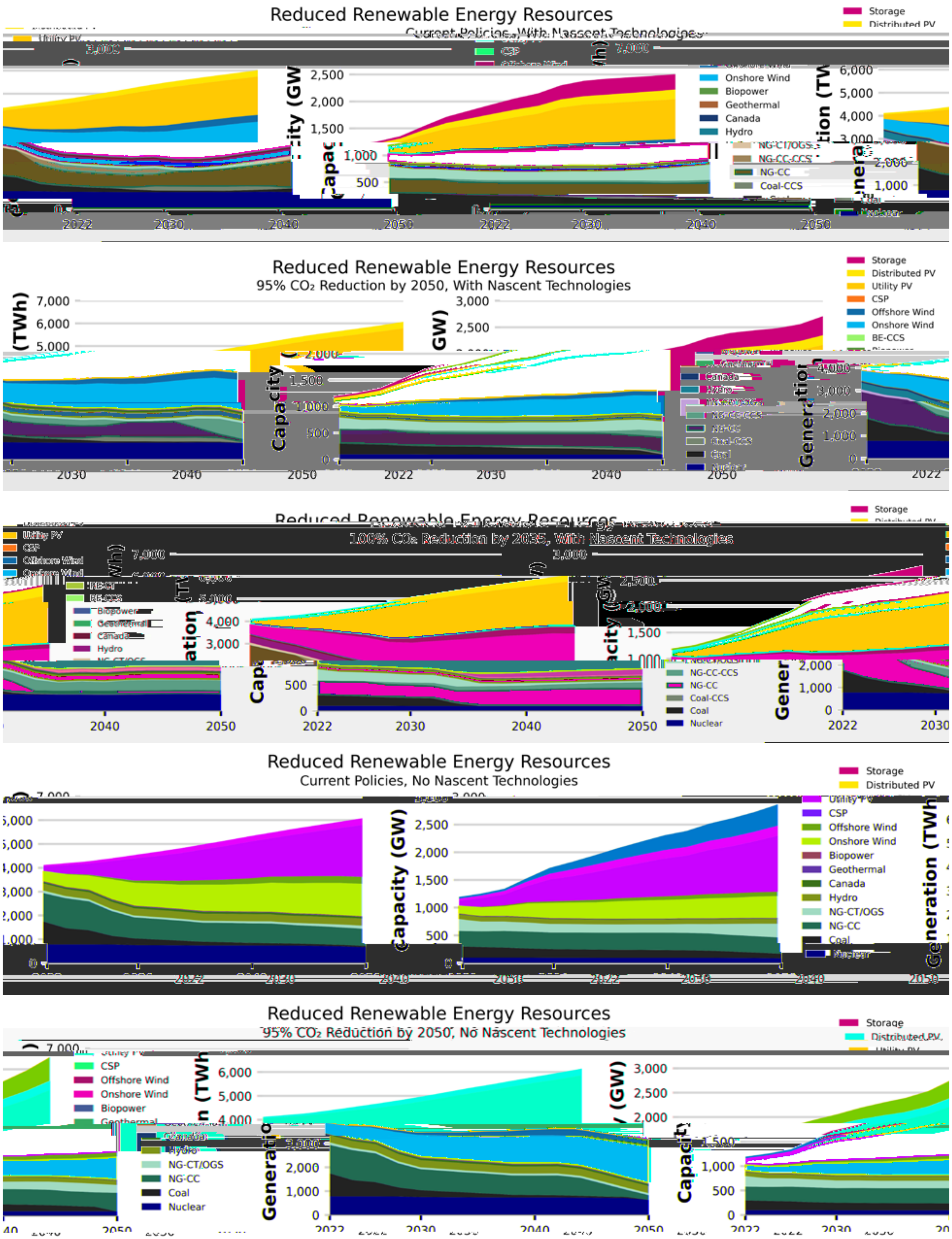

Figure A-11. Reduced Renewable Energy Resources sensitivity: Generation and capacity

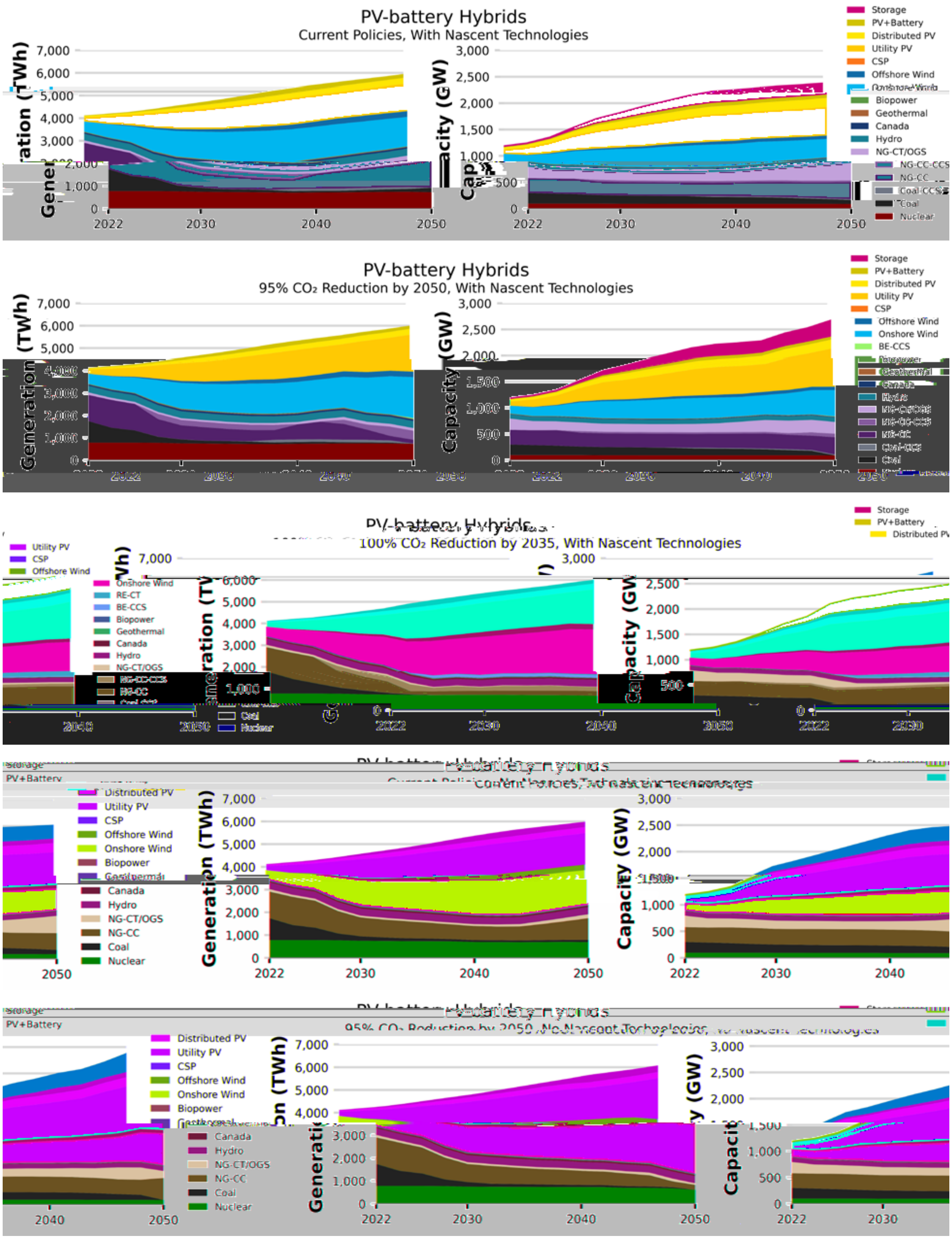

Figure A-12. PV-battery Hybrid sensitivity: Generation and capacity

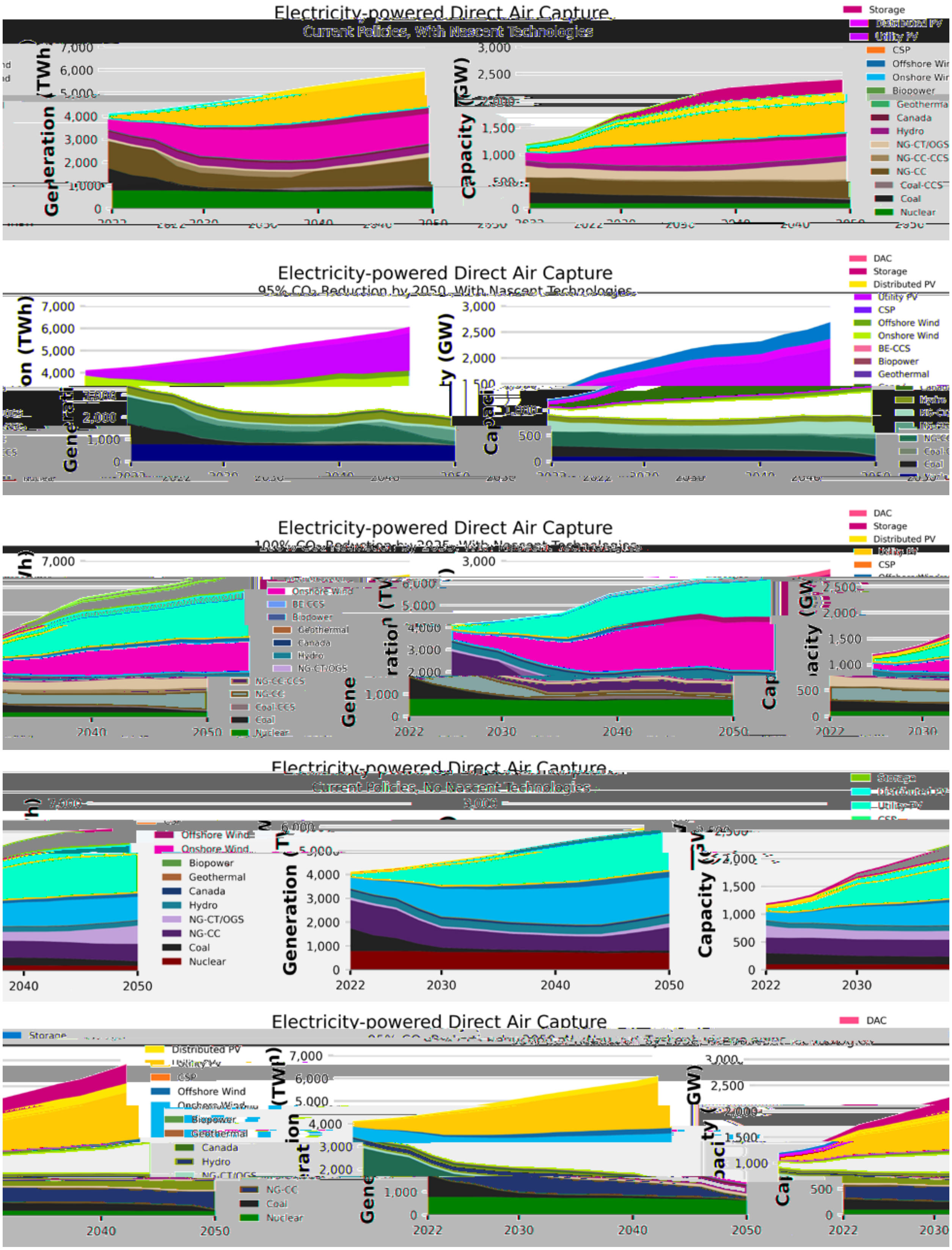

Figure A-13. Electricity-powered Direct Air Capture sensitivity: Generation and capacity

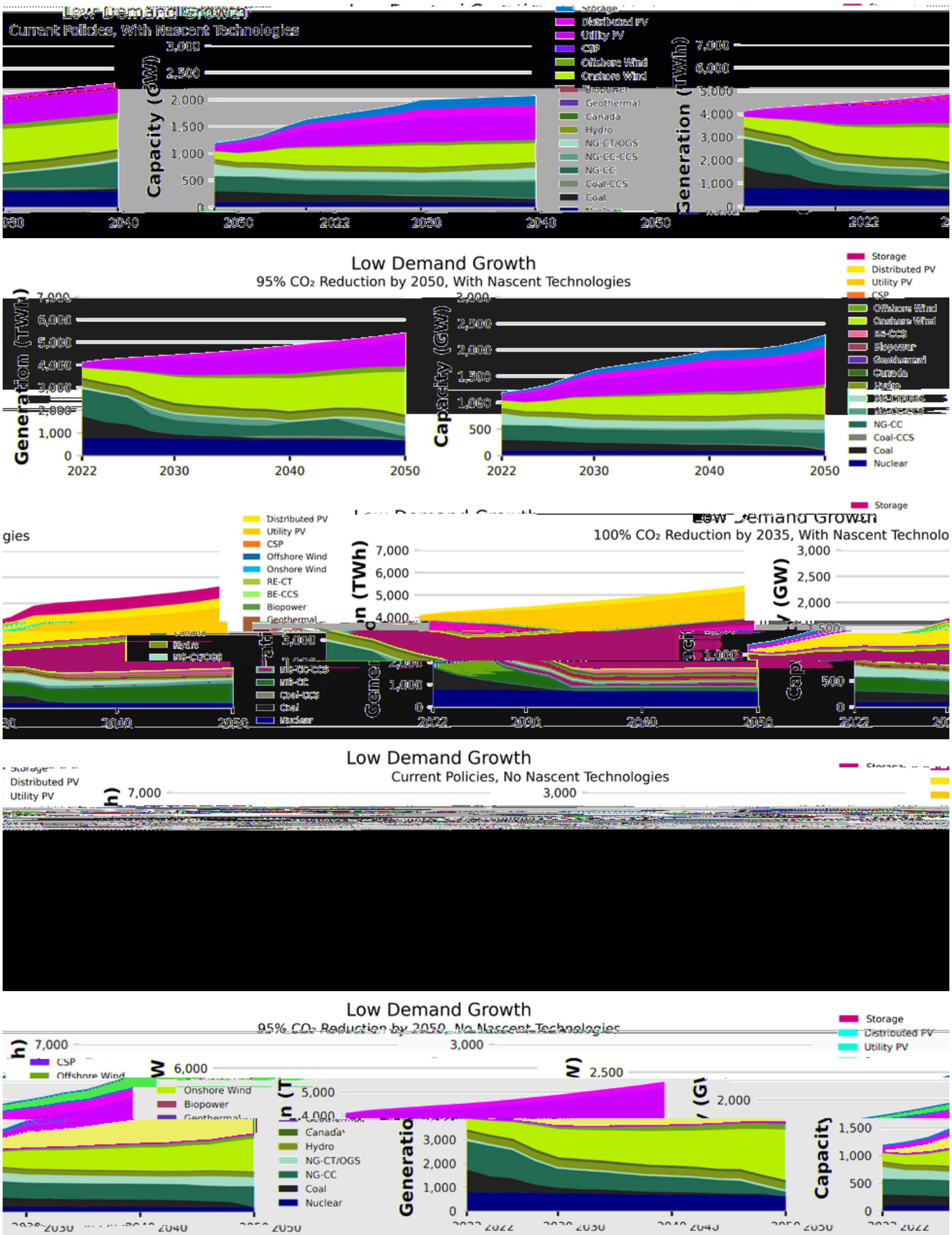

Figure A-14. Low Demand Growth sensitivity: Generation and capacity

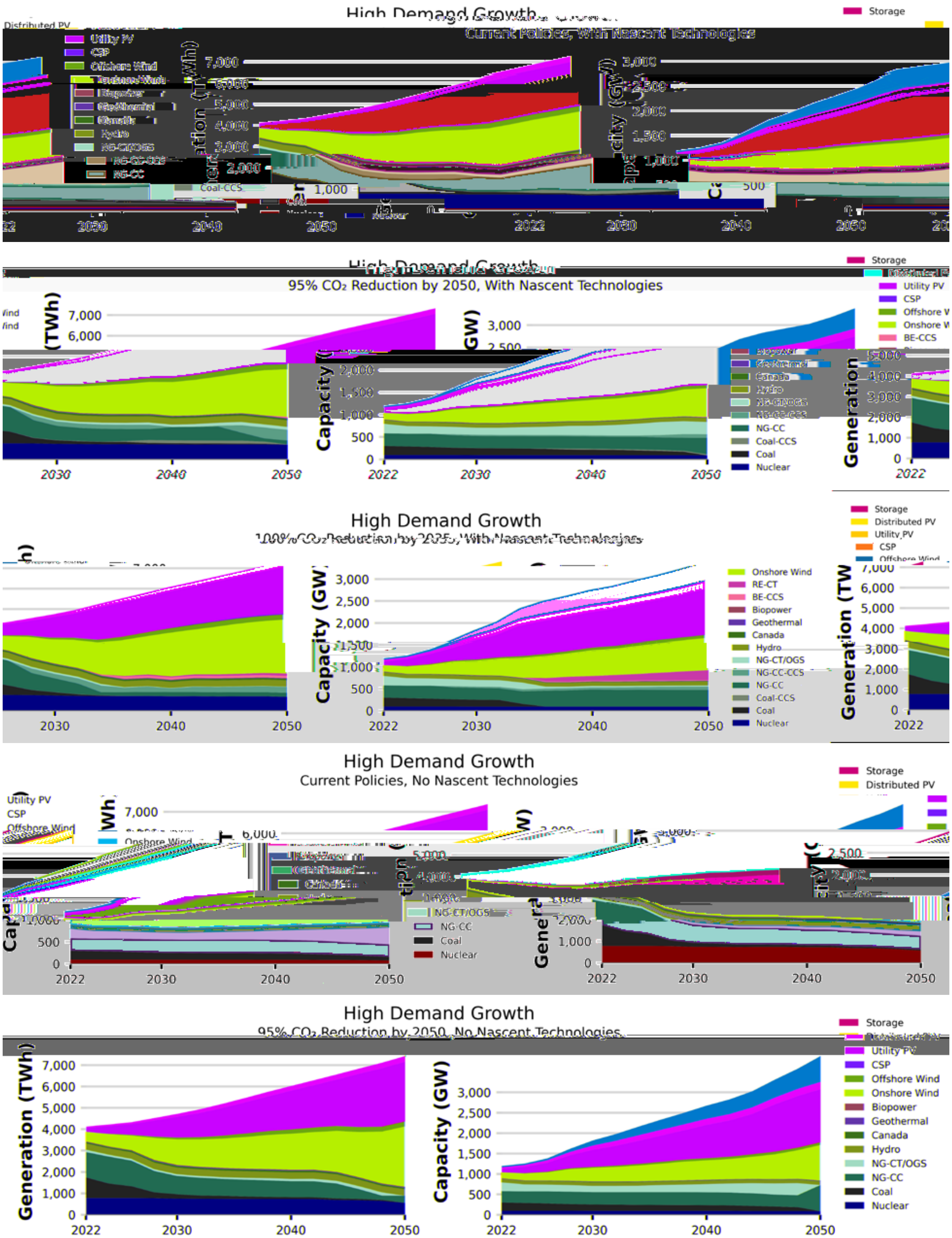

Figure A-15. High Demand Growth sensitivity: Generation and capacity

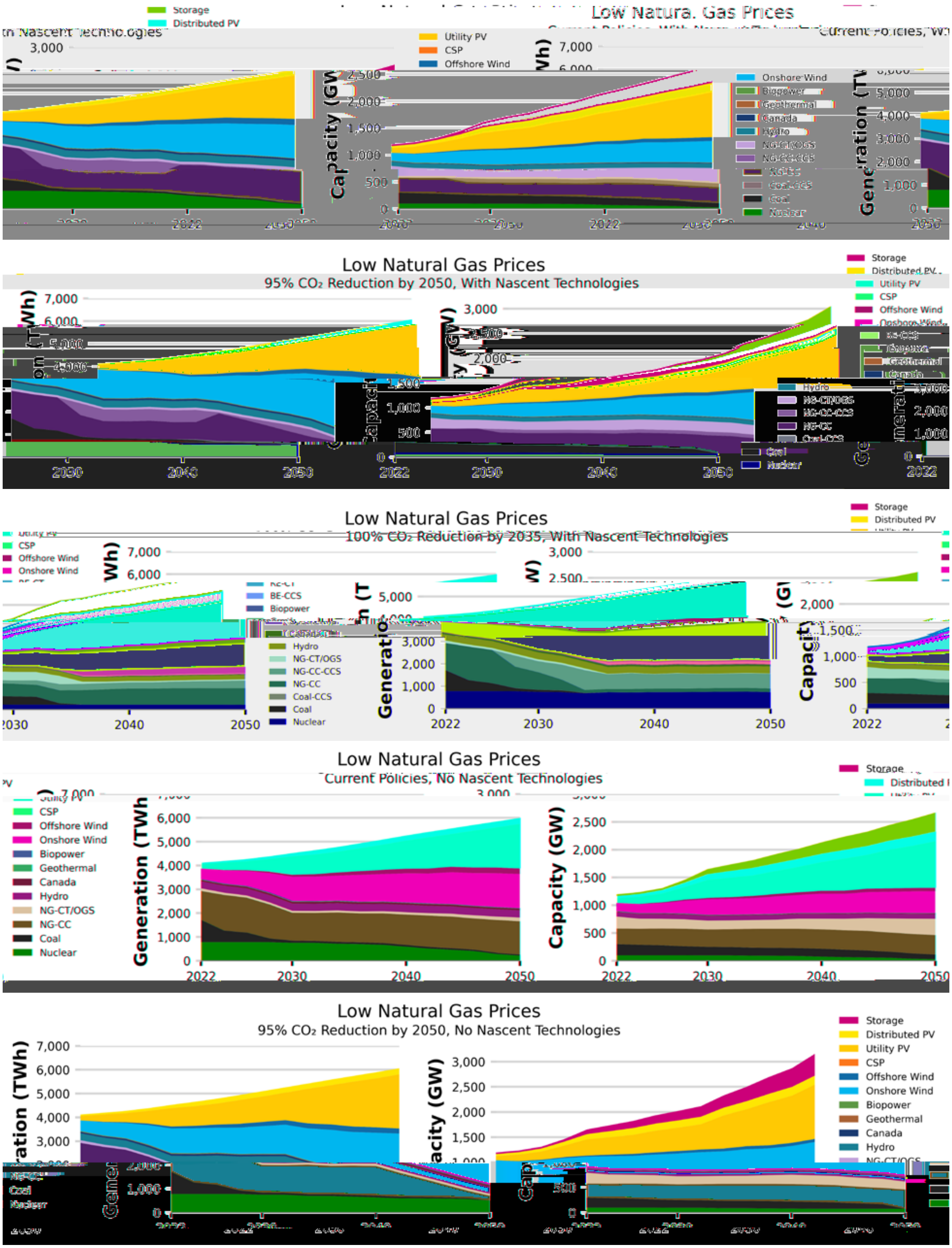

Figure A-16. Low Natural Gas Price sensitivity: Generation and capacity

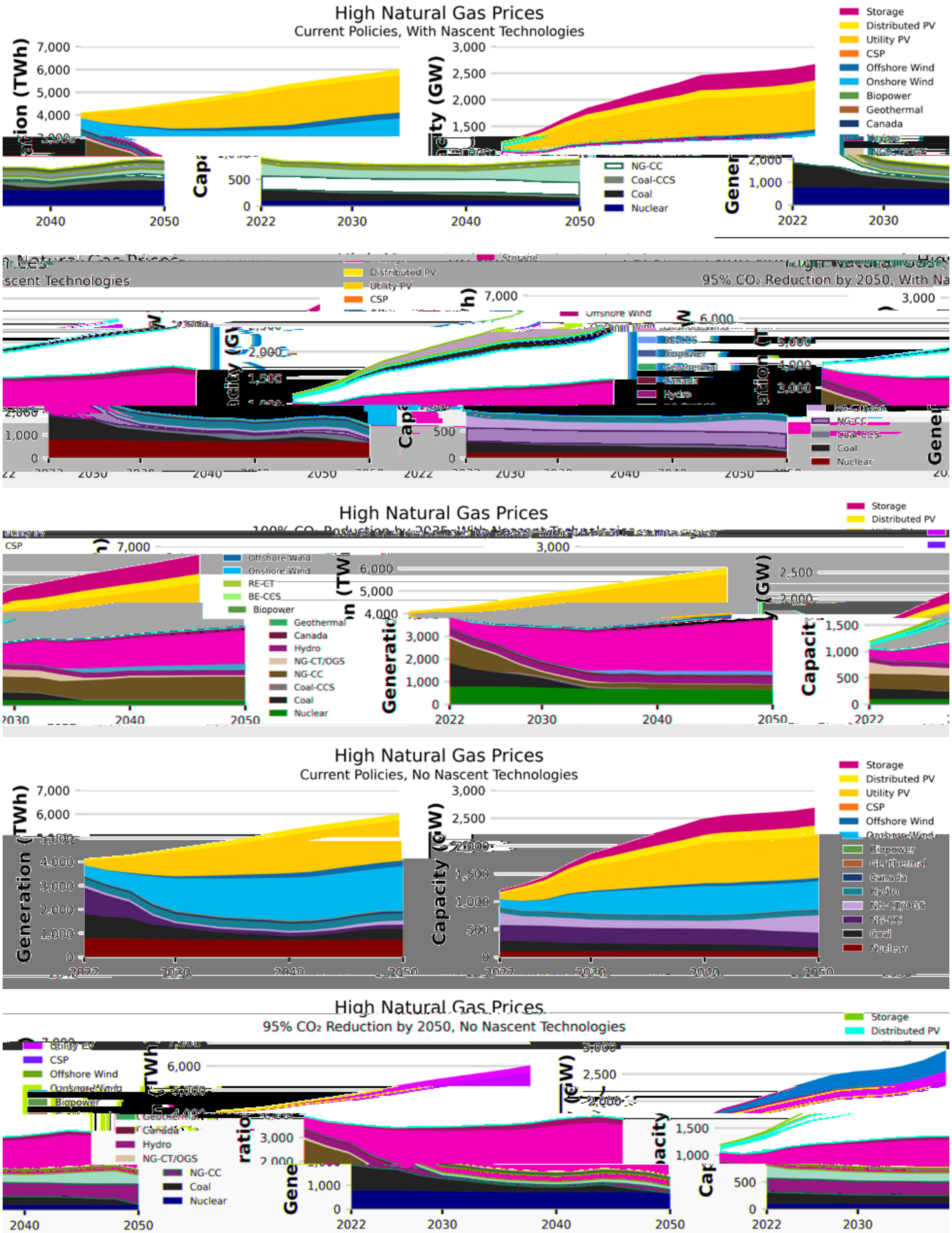

Figure A-17. High Natural Gas Price sensitivity: Generation and capacity

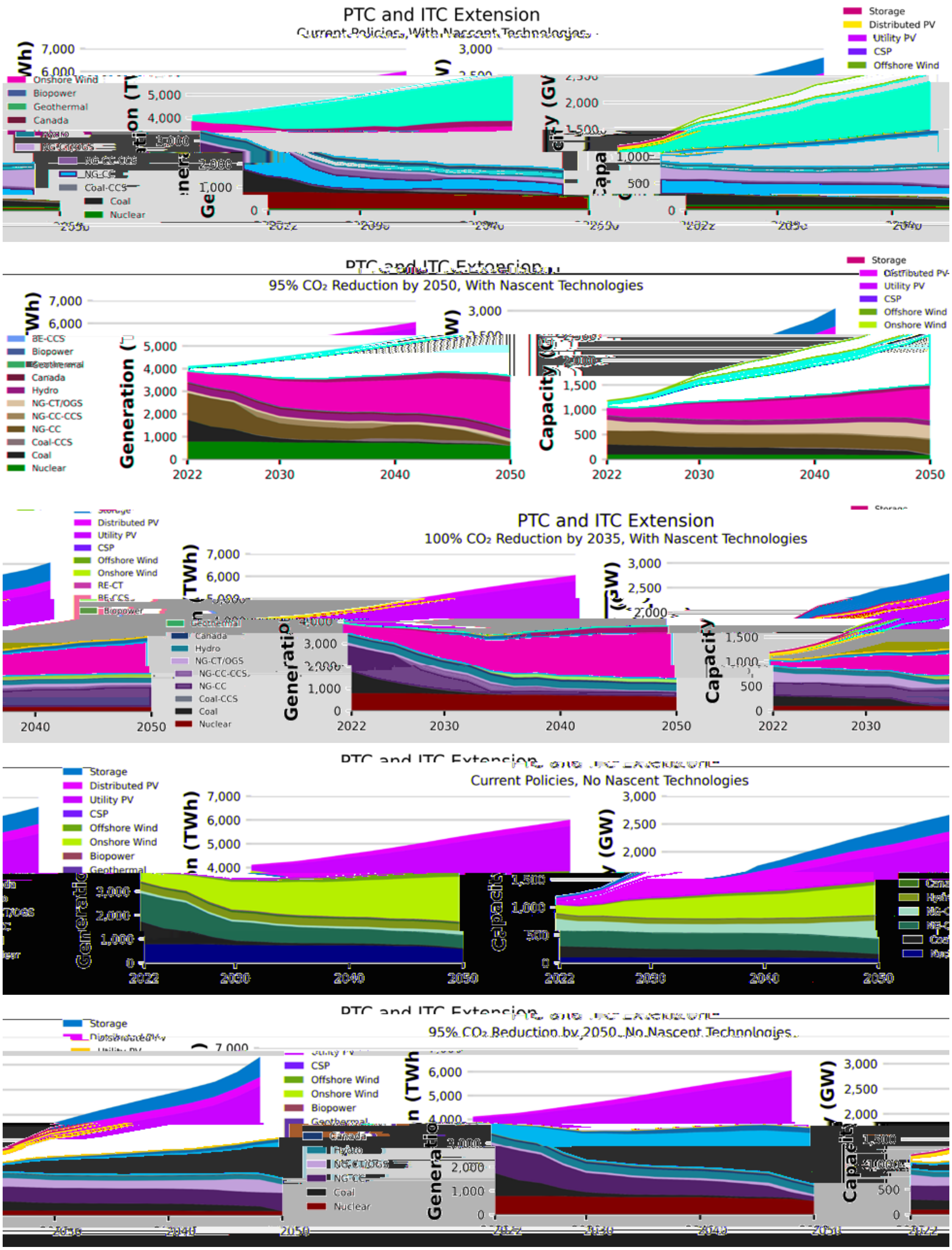

Figure A-18. PTC and ITC Extension sensitivity: Generation and capacity

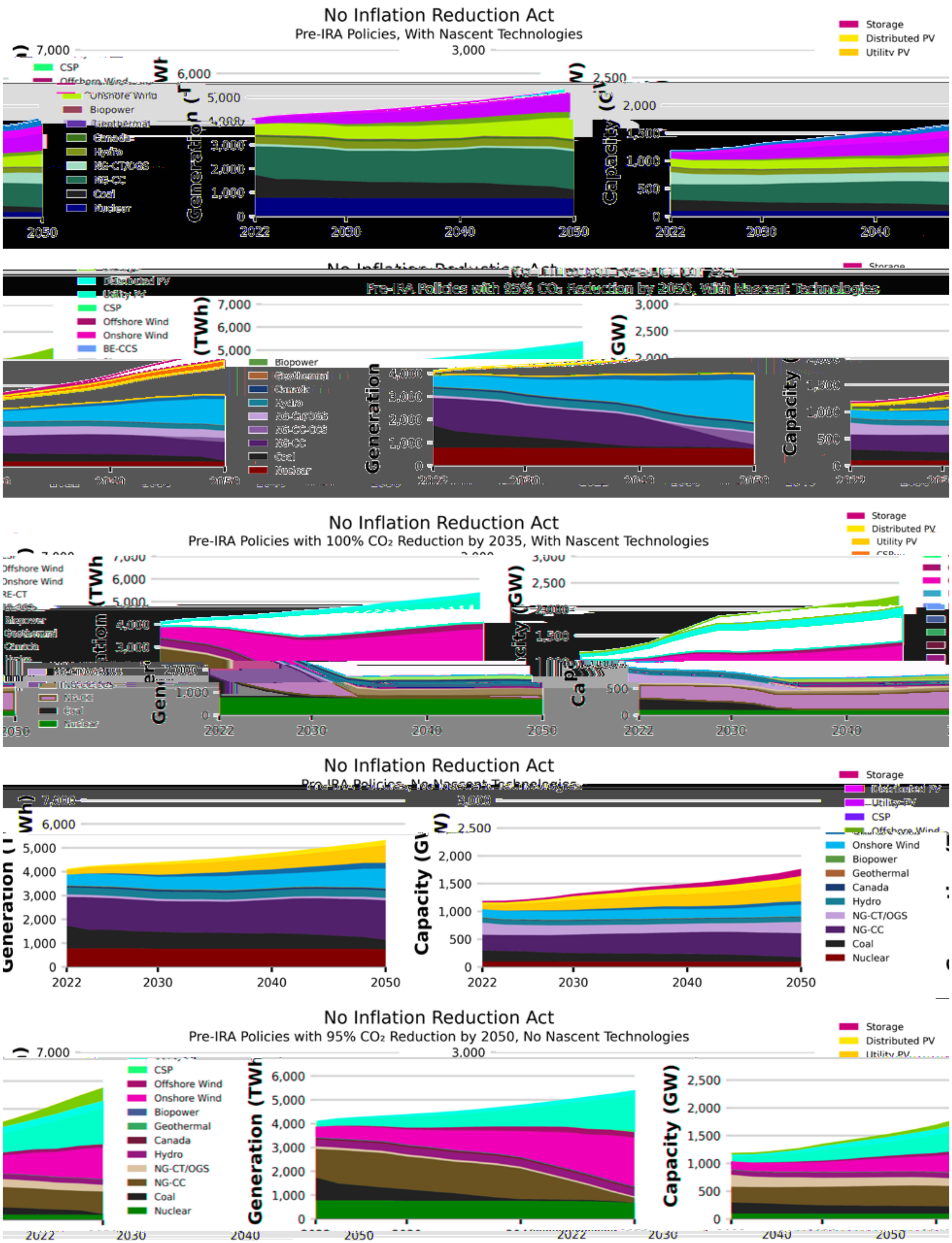

Figure A-19. No Inflation Reduction Act sensitivity: Generation and capacity