EVOLVED ENERGY RESEARCH

UNITED STATES ANNUAL DECARBONIZATION PERSPECTIVE 2022

ABOUT THIS REPORT

This report investigates options for long-term deep decarbonization pathways for the United States. It inaugurates a series of annual updates that aim to move pathways analysis beyond isolated proofs-of-concept towards becoming a practical implementation tool for addressing next-stage challenges in energy and climate change mitigation.

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EVOLVED ENERGY RESEARCH

ABOUT EVOLVED ENERGY RESEARCH

Evolved Energy Research (EER) is a research and consulting firm focused on questions posed by transformation of the energy economy. Their consulting work and insight, supported by sophisticated technical analyses of energy systems, are designed to support strategic decision-making for policymakers, stakeholders, utilities, investors, and technology companies.

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I INTRODUCTION

Purpose of this Report

This report investigates options for long-term deep decarbonization pathways for the United States. These are detailed technical blueprints for the transition to a net-zero economy, including the production and use of energy, the land carbon sink, and non-energy greenhouse gas emissions. We used sophisticated, fine-scaled software modeling to map the infrastructure changes, technologies, and costs required to reach carbon neutrality by mid-century along various alternative pathways, while maintaining U.S. economic productivity and a reliable energy system. A growing list of long-term pathways studies in the last few years indicates increasing interest in this type of work. However, a lack of transparency and standardization across these studies renders comparison of results, methods, data sources, and input assumptions difficult. Pathways studies to date are largely a set of one-off snapshots of possible futures, with relatively little coordination between research efforts or continuity over time.

This report inaugurates a series of annual updates that aim to move pathways analysis beyond isolated proofs-of-concept towards becoming a practical implementation tool for addressing next-stage challenges in energy and climate change mitigation. It uses the EnergyPATHWAYS and RIO modeling platforms, widely recognized as best-in-class, in combination with the most current data on technology cost and performance, to refresh and expand the analysis first reported in the scholarly journal *AGU Advances*, with technical appendices and databases, in 2021.

The annual update results are being reported online on ClimateDeck, managed by the Rhodium Group, and accompanied by a publicly available database of results and input assumptions. This provides a standard, public benchmark for use in technical analysis and policy making and allows year-on-year comparisons highlighting how new developments in technologies, costs, policies, and global markets affect the outcomes of different decarbonization decisions, and what policy or investment course corrections may be needed.

The objectives of this project, supported by Breakthrough Energy, are similar in some ways to those of the U.S. Department of Energy's *Annual Energy Outlook* (AEO): providing an annually refreshed objective benchmark for use by a wide variety of audiences. The AEO is an indispensable tool, but where the AEO's focus is a long-term forecast of business as usual, our analysis is focused specifically on pathways to deep decarbonization to enable better decision making by policy makers, better informed advocacy, and more clarity for the business community.

Policy Relevance

This report does not prescribe policy, but it does highlight what policy outcomes and technological advances are needed to meet climate goals. It informs investment planning for capital intensive businesses, points to critical gaps in R&D, quantifies potential land use and socio-economic transition challenges, clarifies the risks of overreliance on specific technologies, and helps focus the energy policy debate on useful questions.

The Inflation Reduction Act (IRA) of 2022 is a major event in federal climate policy and can help the U.S. make important steps on the path to net-zero. Many of its provisions, especially those accelerating the growth of carbon-free electricity and vehicle electrification by providing policy certainty for the next decade, move in the direction indicated by our earlier work and confirmed by the findings of this study.

While the IRA addresses several key climate mitigation priorities for the 2020s, it will not by itself lead the U.S. to net-zero by mid-century. Its successful implementation will largely depend on the actions of state and local government, utilities, manufacturers, and citizen-consumers. It has important gaps in reducing near-term emissions. It only begins to address some of the decarbonization challenges of the 2030s and beyond.

By mapping pathways to net-zero with high resolution, this report and subsequent annual updates can inform implementation of the IRA at many levels, identify what additional policies will be needed, and help decision-makers and society at large to anticipate future choices and prepare for changes along the way.

II ANALYSIS FRAMEWORK

This analysis addresses the questions "what are the infrastructure, spending, and natural resources requirements needed to decarbonize the U.S. economy by mid-century?" and "how does this change if factor X is adjusted?" Factor X represents many variables of potential importance, from technology breakthroughs, to rates of consumer adoption, to changes in oil prices, to societal restrictions on what technologies or land uses are allowed. The questions are answered by the modeling of scenarios and sensitivities, and comparison of the model results.

Scenarios

Scenarios represent different avenues to decarbonization based on societal preferences or policy restrictions regarding what technologies and resources may or may not be used, for example nuclear power or biomass, though they share many commonalities. For each scenario, the pathway to net-zero greenhouse gas emissions in 2050 is modeled in every year starting from the present, for all the infrastructure stocks and activities within all major economic sectors and subsectors, with a temporal granularity of every hour of the year for electricity, and a geographic granularity of 27 separate regions into which the U.S. is divided.

There are eight distinct scenarios, which are briefly described in Table 1 below. Six of these are very similar to those in our previous analysis (Link). This is partly for comparison purposes, but primarily because we think these still represent the most salient forks in the road for decarbonization in the U.S. Two new scenarios, "Drop-In" and "High Hydrogen," have also been added.

TABLE 1. Scenarios

Scenario	Description
Baseline	This is a business-as-usual scenario based on the DOE's Annual Energy Outlook 2022. It has the same demand for energy services as the net-zero cases but does not achieve deep decarbonization. It is used as a basis of comparison for the cost, emissions, infrastructure, land use and other attributes of the net-zero cases.
Central	This is the least-cost pathway for achieving net-zero greenhouse gas emissions by 2050 in the U.S. It is economy-wide and includes energy and industrial CO_2, non-CO_2 GHGs, and the land CO_2 sink. It is built using a high electrification demand-side case, and on the supply-side has the fewest constraints on technologies and resources available for decarbonization.
Drop-In	This net-zero scenario prioritizes maintaining the use of existing infrastructure to the greatest extent possible consistent with carbon neutrality, implemented by placing cost penalties on new infrastructure build, delaying the uptake of electrification technologies by twenty years, and avoiding the uptake of other zero-carbon fuel-using technologies (hydrogen and ammonia). It is designed to explore the effects of trying to minimize dislocation on the existing energy industry in the U.S.
High Hydrogen	This net-zero scenario emphasizes the direct use of hydrogen in some applications in which the potential for electrification is uncertain, specifically in industry and heavier vehicles. It is designed to explore the effects of a hydrogen economy that extends all the way to energy end-users.
Low Demand	This net-zero scenario reduces the demand for energy services from that used in the other net-zero scenarios. It is designed to explore how high levels of conservation and energy efficiency, achieved through behavior, planning, policy, and other means, could reduce requirements for low-carbon infrastructure and land.
Low Land	This net-zero scenario limits the use of land-intensive mitigation solutions, including bioenergy crops, wind and solar power generating plants, and transmission lines. It is designed to explore the effect of societal barriers to the siting of low-carbon energy infrastructure for environmental and other reasons.
Slow Consumer Uptake	This net-zero scenario delays by twenty years the uptake of fuel-switching technologies including electric vehicles, heat pumps, fuel-cell vehicles, etc. It is designed to explore the effects of slow consumer adoption on energy system decarbonization, including the impacts on electricity and alternative fuel demand.
100% Renewables	This net-zero scenario allows only wind, solar, biomass, and other forms of renewable energy by 2050. It is designed to explore the effects of eliminating fossil fuels and nuclear power altogether on energy infrastructure, electric power, and the production of alternative fuels and feedstocks.

Sensitivities

Sensitivities begin with the **Central** scenario (except where noted) and determine the effects on the energy system of changing a single key variable. There are fourteen separate sensitivities, described in Table 2 below. Many of these relate to the readiness and expected cost of potentially important technologies, for example direct air capture. Others relate to future fossil prices, the effects of changing the year in which the net-zero target is reached, and the requirements for reaching net-negative emissions.

TABLE 2. Sensitivities

Sensitivity	Description
Baseline Low Fossil Fuel Price	This sensitivity uses a low long-term fossil fuel price forecast in the baseline case. It shows the effect of low fossil fuel prices on business as usual and provides a point of comparison for the low fossil fuel price sensitivity based off the **Central** scenario.
Baseline Low Renewables Cost	This sensitivity uses a low long-term renewable energy technology cost forecast in the baseline case. It shows the effect of low renewable cost on business as usual and provides a point of comparison for the **Low Renewable Cost** sensitivity based off the **Central** scenario.
Low Fossil Fuel Price	This sensitivity explores the changes in energy system infrastructure and cost in the **Central** scenario when low long-term fossil fuel prices are assumed.
Low Renewables Cost	This sensitivity explores the changes in energy system infrastructure and cost in the **Central** scenario when low long-term renewable technology costs are assumed.
Nuclear Breakthrough	This sensitivity explores the changes in energy system infrastructure and cost when a breakthrough in nuclear technology is assumed (50% reduction in new reactor costs) in the **Centra**l scenario.
DAC Breakthrough	This sensitivity explores the changes in energy system infrastructure and cost when a breakthrough in direct air capture (DAC) costs is assumed (50% reduction) in the **Central** scenario.
High Flexible Load	This sensitivity explores the changes in energy system infrastructure and cost when higher levels of flexible end-use load (e.g., EVs, water heating, space heating) are assumed in the **Central** scenario.
No Sector Coupling	This sensitivity explores the changes in energy system infrastructure and cost in the **Central** scenario when there is no dynamic coupling between the electricity and fuel-supply sectors, and electric loads and technologies such as electrolyzers and electric boilers operate like many of today's loads, without any signal as to when they should operate to minimize electricity cost.
Limited Biomass	This sensitivity explores the changes in energy system infrastructure and cost in the **Central** scenario when the availability of biomass feedstocks (specifically purpose-grown energy crops) is constrained.

Sensitivity	Description
Transmission Constrained	This sensitivity explores the changes in energy system infrastructure and cost in the central case when there is limited ability to expand transmission capacity. It is implemented via a 50% constraint on MW-miles of transmission compared to the unconstrained **Central** scenario.
Net-Zero by 2045	This sensitivity explores the changes in energy system infrastructure and cost in the **Central** scenario when the net-zero GHG target is accelerated to 2045.
Net-Zero by 2060	This sensitivity explores the changes in energy system infrastructure and cost in the **Central** scenario when the net-zero GHG target is delayed to 2060 and the Biden 50-52% target in 2030 is not reached.
Net-Zero CO_2-Only	This sensitivity explores the changes in energy system infrastructure and cost in the **Central** scenario when only CO_2 is reduced to net-zero by 2050, and non-CO_2 gases are not addressed.
Net Negative	This sensitivity is the least-cost pathway to economy wide net-negative GHGs by mid-century (-500 Mt CO_2e in 2050), consistent with returning global warming to 1ºC by 2100.

III MODELING UPDATES

Data Updates

As part of the annual update to our modeling, we engaged in a review of key data sources. Some data sources are on an annual update cycle and in these cases, we updated to the most recent versions that were available for inclusion as of June 1, 2022. This included:

- The U.S. Department of Energy's Annual Energy Outlook 2022 (Link) for energy service demand, equipment stocks, and baseline demand technology forecasts; fossil fuel prices; and delivery prices for different energy carries (electricity, pipeline gas, etc.)
- The National Renewable Energy Laboratory's Annual Technology Baseline 2021 (Link) for renewable costs and performance.

We additionally updated foundational sources for key technologies shown in the table below.

TABLE 1. Updated and new technology data sources

Technology	Sources
Nuclear	• Rasti, Maryam, "Nuclear small modular reactors: an analysis of projected cost estimates and economic competitiveness"; Link • "The Future of Nuclear Energy in a Carbon-Constrained World" (Massachusetts Institute of Technology Interdisciplinary Study, 2018; Link)
HEFA Jet Fuel	• Pavelenko et. al, "The cost of supporting alternative jet fuels in the European Union" (The International Council on Clean Transportation, 2019; Link)
Thermal Energy Storage	• "Innovation Outlook: Thermal Energy Storage" (International Renewable Energy Agency, 2020; Link)
Industrial Heat Pumps	• P. Capros et al., "Technology Pathways in Decarbonisation Scenarios" (Advanced System Studies for Energy Transition, 2018; Link)
Hydrogen Storage	• Argonne National Laboratory, "System Level Analysis of Hydrogen Storage Options" (Project Id: ST001 U.S. Department of Energy Hydrogen and Fuel Cells Program; Link) • Lord, Anna S., "Overview of Geologic Storage of Natural Gas with an Emphasis on Assessing the Feasibility of Storing Hydrogen" (Report No SAND2009-5878, Sandia National Laboratories, 2009; Link)
BECCS H_2	• G. del Alamo et al., "Implementation of Bio-CCS in Biofuels Production" (Task 33 Special Project ISBN 978-1-910154-44-1, IEA Bioenergy, 2015; Link). • National Renewable Energy Laboratory, "Hydrogen Production Cost Estimate Using Biomass Gasification" (National Renewable Energy Laboratory, 2011: Link)
Hydrogen and Ammonia Transmission Costs	• D. DeSantis et al., "Cost of long-distance energy transmission by different carriers" (iScience, 2021; Link)

Finally, our updated modeling approach includes the use of supply curves for the land sector and non-energy, non-CO_2 emissions that were derived from the sources listed in the table below.

TABLE 2. Sources for newly modeled emissions domains.

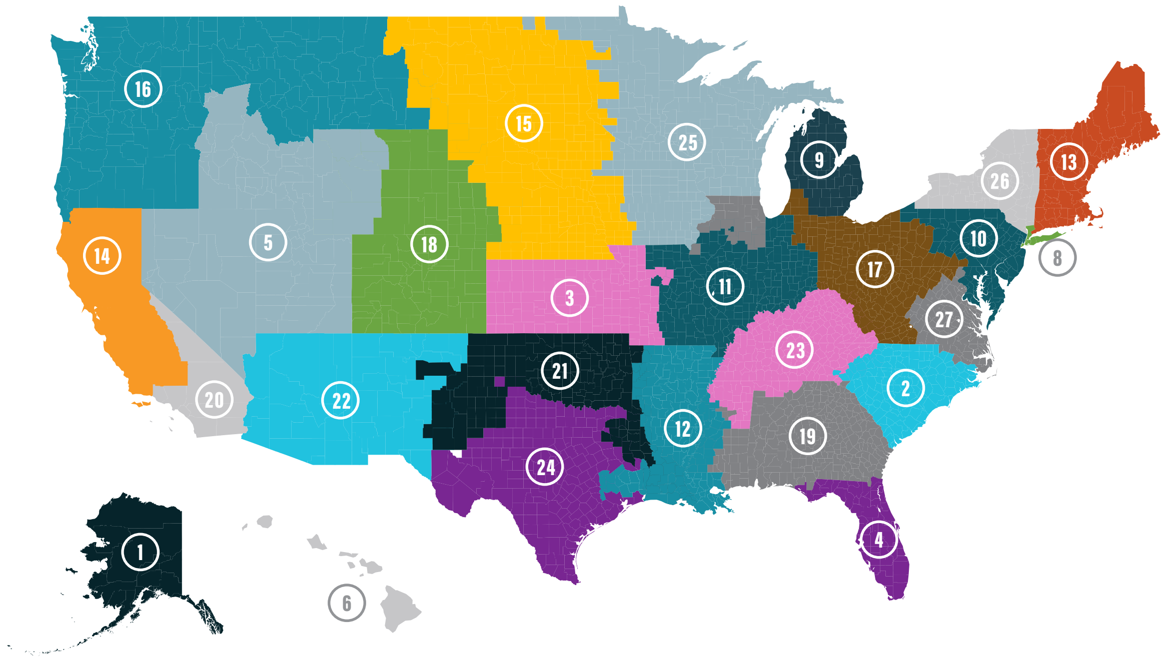
Emissions Category	Source
Land Sector	• Fargione et al., Natural climate solutions for the United States, *Science Advances* **4**, (2018); Link • White House. "United States mid-century strategy for deep decarbonization." United Nations Framework Convention on Climate Change, Washington, DC. 2016; Link
Non-Energy, Non-CO_2	• "Global Non-CO_2 Greenhouse Gas Emissions Projections and Mitigation" (U.S. Environmental Protection Agency, Office of Atmospheric Programs, 2019, Link)

Transmission and Pipeline Modeling

Improvement: We've increased the spatial granularity of our modeling from 16 to 27 zones to allow for a better representation of the cost of moving energy and CO_2. This representation includes all electricity market module regions used by the EIA in *Annual Energy Outlook 2022* and additionally includes representations of Hawaii and Alaska (the EIA models only the lower-48 electricity system). The 27 model zones (Figure 2) follow NERC, ISO, and RTO regional boundaries and use the geographic names from EIA's National Energy Modeling System (NEMS), which are approximations of jurisdictional borders (for example, the "Texas" zone does not fully conform to the borders of that state).

FIGURE 1.

Zonal Representation in the Model

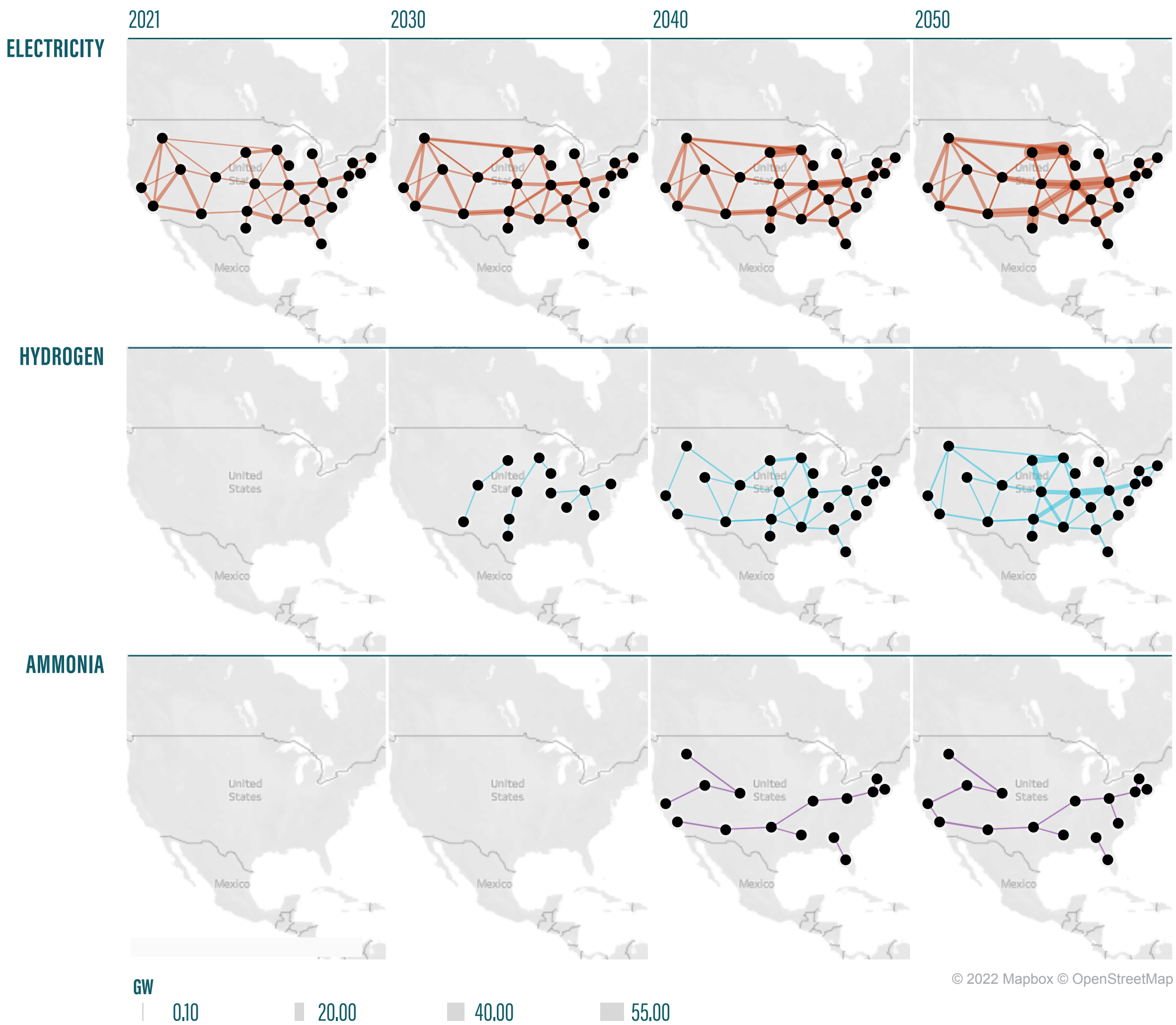


1	Alaska	8	Metropolitan New York	15	Northern Great Plains	22	Southwest
2	Carolinas	9	Michigan	16	Northwest	23	Tennessee Valley
3	Central Great Plains	10	Mid-Atlantic	17	Ohio Valley	24	Texas
4	Florida	11	Middle Mississippi Valley	18	Rockies	25	Upper Mississippi Valley
5	Great Basin	12	Mississippi Delta	19	Southeast	26	Upstate New York
6	Hawaii	13	New England	20	Southern California	27	Virginia
7	Metropolitan Chicago	14	Northern California	21	Southern Great Plains		

In addition to increasing geographic granularity, we have also added explicit representations of new pipeline capacity for transporting hydrogen, ammonia, and CO_2. In addition to new electricity transmission, we also added the ability to model reconductoring of existing electricity transmission corridors (up to 50% of existing transmission capacity) which we assume can be done at a lower cost than building transmission on new rights of way. Figure 3 shows maps of electricity, hydrogen, and ammonia transmission and pipeline infrastructure development by decade.

FIGURE 2.

Transmission and Pipeline Maps, Central Scenario. Dots represent model zones, and the colored lines show transmission or pipelines between zones. The thickness of the line indicates the size of the connection.



Result: By increasing the number of modeled zones, and by allowing new mechanisms of low-cost energy flow between them, compared to our previous work we see increased opportunities to access high-quality renewables in the middle of the country. Where previously this would necessitate electricity transmission, the use of pipelines to deliver produced hydrogen and ammonia represents a lower-cost way of delivering renewable energy destined for fuel applications, specifically to the midwestern and eastern regions of the country.

Nuclear Technologies

Improvement: We have expanded the representation of nuclear technologies from a single generic Gen III nuclear power plant to two main nuclear configurations: small modular reactors (SMRs) and high-temperature gas reactors (HTGRs).

1. **Small modular reactors (SMRs).** SMRs are modeled as operating at conventional light-water reactor temperatures. They can either be built new or retrofitted at existing coal power plant sites. Capacity allocation and operational decisions among reactors, thermal storage, and steam turbine generators are independent in the model, allowing for flexible system designs depending on electricity system needs.

2. **High temperature gas reactors (HTGRs)**. HTGRs are modeled as producing heat at sufficiently high temperatures (>750 °C) to power highly efficient steam cycles, support high-temperature electrolysis, and provide thermal inputs for direct air capture. They can either be built new or retrofitted at existing coal power plant sites. In the model, these reactors can also be built in conjunction with thermal energy storage. This allows for a variety of plant configurations that can variously generate clean electricity, produce carbon-free hydrogen, and/or capture atmospheric CO_2.

Result: The model improvements show an expanded economic potential for nuclear generators. This results from including additional economic advantages (retrofit over new build), applications (hydrogen production and direct air capture), and temporal flexibility (allowing for thermal energy storage of produced heat) that are critical to nuclear economics in systems with high levels of low-cost renewables.

For a host of reasons, the authors are agnostic on the likelihood of commercial success of any particular reactor technology in the U.S. We have specifically added the distinction between SMRs and HTGRs because their different operating temperatures mean they are more or less suitable for supporting high-temperature heat applications. These technologies are represented with different reactor and fuel cycle costs, but in the modeling don't appear to be drastically different in terms of economic competitiveness. For comparison to other analyses that don't include heat storage and applications, the levelized cost of energy (LCOE) of an SMR and HTGR operating in conventional power plant mode (that is, reactors supporting only electricity production at a 95% capacity factor) are shown in Table 3.

TABLE 3. LCOE of nuclear technologies, electricity production only

Technology	Electricity-only LCOE ($/MWh)
SMR	$58
HTGR	$64

When only electricity is needed, the model shows SMRs to be more competitive. When other applications requiring high-temperature heat become economic, HTGRs are constructed. In future modeling efforts, expanding the potential heat uses of nuclear to additional industrial processes in which temperature requirements may be lower and reactor size may be more important, may allow for the integration of SMRs into industrial heat.

Industrial Decarbonization

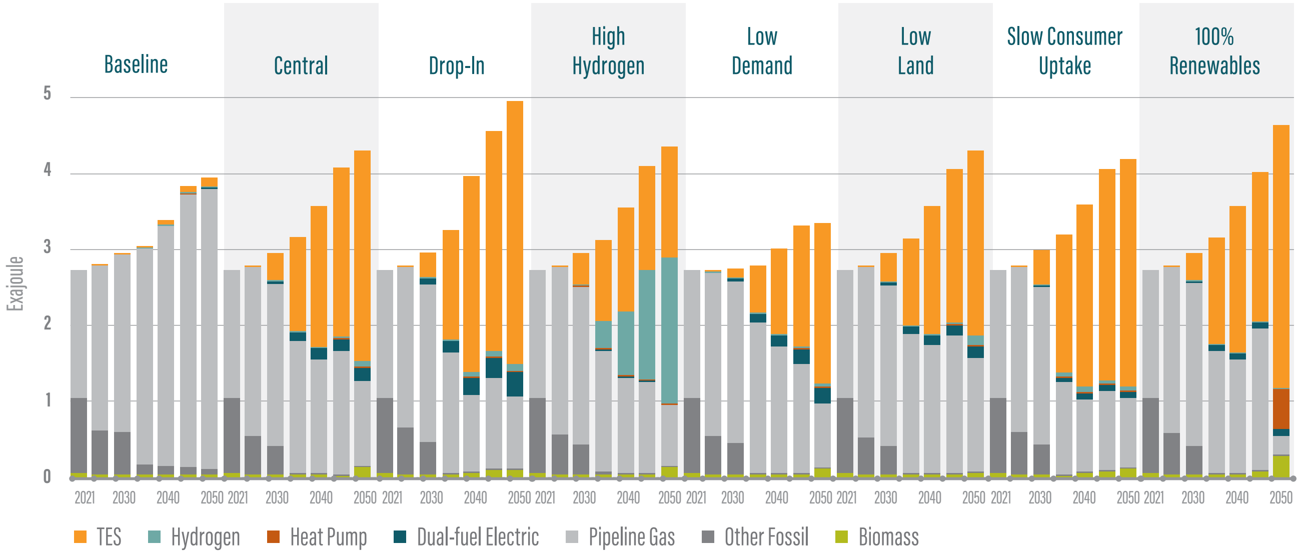
Improvement: We have added complexity to the modeling of industrial heat, so that we now can decarbonize industrial steam supply by employing three strategies that can be applied separately or in combination:

1. **Hybridization**: Hybridization builds redundancy into industrial boiler systems in the form of 'dual-fuel' boilers, where electric boilers are operated when electricity system conditions support their use (i.e. when renewable energy is available) and switching to fuel boilers (sometimes hydrogen) during the limited hours where their use would be supported by thermal generators. Our previous work used this strategy. Result: This strategy enhances reliability for both steam and electricity supply.

2. **Thermal Energy Storage**: Adding thermal storage allows for the 'charging' of heat when there is a plentiful supply of renewable energy and 'discharging' it when heat is needed and electricity system conditions are less advantageous. Result: Thermal storage is cheaper than electricity storage and provides renewable energy balancing at lower cost.

3. **Heat Pumps**: When renewables are in high demand or the use of steam production as a renewable balancing load is less attractive economically, heat pumps can reduce the overall amount of electricity needed to produce heat, using either ambient air or waste heat (which the heat pump upgrades to necessary temperatures). Result: High capital costs combined with low capacity factors limit the value of heat pumps in applications calling for flexible operation though they are still used as efficient electric heating sources; technology progress that reduces their upfront costs would encourage their deployment.

FIGURE 3.
Steam Production



Storage Technologies

Improvement: Our work to date has found that sector coupling is critical to the economics of highly renewable electricity systems, and significant analytical resources in the model formulation are dedicated to exploring this area. In the current update, we've expanded the number of technologies that can be built to store energy in different forms to balance supply and demand across a variety of energy carriers.

TABLE 4. Storage Technologies Used in the Modeling

Energy Carrier	Technology	Minimum Duration (hours)	2022 Update
Electricity	Li-Ion	1	(existing)
Electricity	Long-Duration Storage	24	(existing)
Heat	Industrial thermal energy storage in boiler systems	1	✓
Heat	High temperature (>750 °C) thermal storage for nuclear power	1	✓
Heat	Low temperature (<=750 °C) thermal storage for nuclear power	1	✓
Hydrogen	Salt Cavern Storage (limited by geographic availability)	100	✓
Hydrogen	Other Underground Storage	8	✓

This is not an exhaustive list of all potential energy carriers for storage, but liquid fuels, pipeline gas, and ammonia are three examples for which storage costs are sufficiently low, or existing storage infrastructure capacity sufficiently large, to make explicit representation in the model unnecessary.

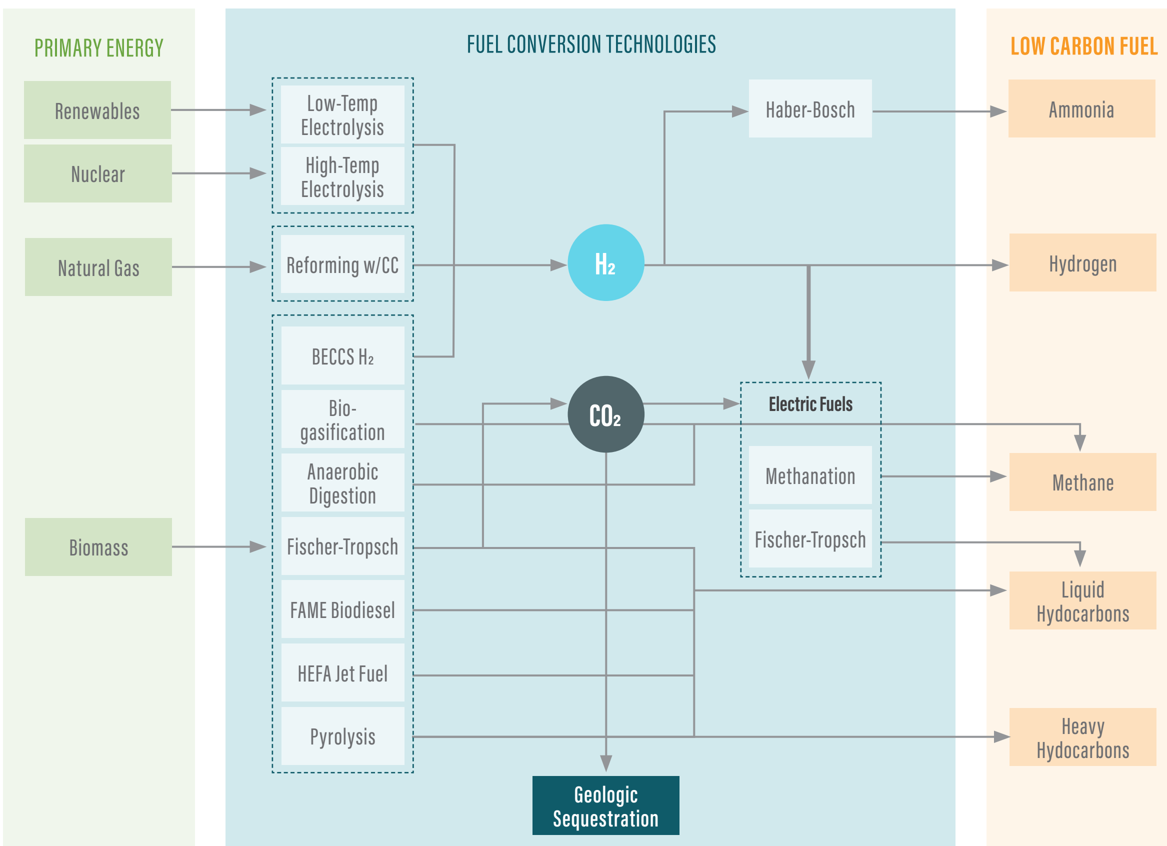
Result: Incorporation of different hydrogen storage technologies (specifically geographically limited salt cavern storage) changes the regional competitiveness of hydrogen and determines the configuration of large-scale hydrogen production and delivery networks. Thermal energy storage (TES) in industry provides a competitor for batteries and allows for additional cost-effective industrial steam decarbonization. TES incorporation in nuclear technologies improves the cost-effectiveness of nuclear power plant deployment and changes the nature of its operations (reduces annual electricity capacity factors).

Fuel Conversion Technologies

Improvement: We model a diverse set of fuel production technologies, using a variety of primary energy sources to produce drop-in fuels for our current energy system (methane, liquid hydrocarbons, and solid hydrocarbons) as well as other energy carriers that grow significantly in decarbonization scenarios (hydrogen and ammonia) and are prioritized due to lower-cost production pathways. The integration of the fuels sector with the electricity sector is critical to the economics of both electricity and low-carbon fuels production and is a key feature of our modeling approach.

FIGURE 4.

Low-Carbon Fuel Production Pathways



Our past work identified fuels pathways and carbon management as some of the major uncertainties in decarbonization pathways. While this finding remains true, in this study we have further developed the representation of fuels systems to better articulate the uncertainties, tradeoffs, and required physical infrastructure for pathways that rely on bio-, electricity-, or fossil-derived fuels. Specifically, this modeling now incorporates the following advances:

- Pipelines for hydrogen, CO_2, and ammonia that allow for freer movement of energy between zones and greater regional specialization. Prior work allowed liquid synthetic fuels to be traded, but hydrogen and CO_2 themselves could not trade between zones.
- The BECCS hydrogen technology has been updated with a new data source that points to this technology being more expensive than in previously modeled. On the modeling methodology front, BECCS hydrogen can no longer be used to synthesize fuels but must be used in demand-side applications. This re-configuration helps separate the bio- and electricity-derived fuel pathways when reporting results.
- New biofuels pathways have been added to the modeling that promote greater near-term applications. These pathways include low-cost biogas, carbon capture to ethanol plants, and FAME biodiesel.
- Existing petroleum refineries have been added to the model to explicitly represent refined fuel production capacity for all types. Not only does this help provide information about the scale of advanced fuel pathways, but new biomass technologies, such as fast pyrolysis, create bio-oil that can be used in existing petroleum refineries to produce refined products at low cost.
- Expansion of biomass supply curves to include explicit representation of all individual feedstocks from the DOE billion-ton study, use of land currently under cultivation for corn ethanol, and biogas potential estimates.
- Explicit representation of methane (from natural gas extraction and delivery) into the modeling framework changes the relative competitiveness of blue-hydrogen (natural gas with carbon capture) in hydrogen production. This includes abatement supply curves for natural gas extraction.

Result: Improved granularity of fuel production inputs (for example, biomass and geologic sequestration inputs); improved spatial granularity; and improved representation of the costs of hydrogen storage and pipelines give increased confidence in model results regarding types, relative quantities, and likely locations of low-carbon fuels production.

Oil & Gas Production

Improvement: Our prior work has focused on areas of the economy that are expanding (e.g., electricity) rather than on those that are contracting (e.g., fossil fuel production) under decarbonization constraints. This is in part because we believe growth areas are where proactive planning has the potential to create the largest societal benefits. Our prior modeling did not include explicit treatment of oil and gas production, only representing downstream fossil fuel products with adjusted emissions factors to account for upstream emissions. Primary production of oil and gas, including domestic extraction, imports, and exports, were not closely examined. In the current study, however, we are now accounting for oil and gas extraction explicitly, both as a consequence of needing to explicitly model all greenhouse gas emissions, and also because of the increasing economic and geopolitical importance of potential U.S. fossil fuel exports.

Result: An important and counterintuitive finding is that under a policy environment that prioritizes domestic production over imported fuels, oil extraction in the U.S. doesn't need to fall until after 2035 in all net-zero scenarios, even though on-road transportation is rapidly electrifying during this period. This also highlights the importance of controlling fugitive emissions from oil and gas production because domestic extraction continues at some level through 2050 in all scenarios except for **100% Renewables**.

Electricity Distribution Modeling

Improvement: The RIO optimization now includes basic representations of distribution loads and infrastructure, which it previously did not. This capability was added because: (1) distribution costs are a large portion of the incremental costs of decarbonization pathways; and (2) investment in decarbonization technologies such as distributed photovoltaics and electrified industrial steam production (thermal energy storage, boilers, and heat pumps), and operations of flexible end-use loads are dependent on both generation and these distribution system conditions.

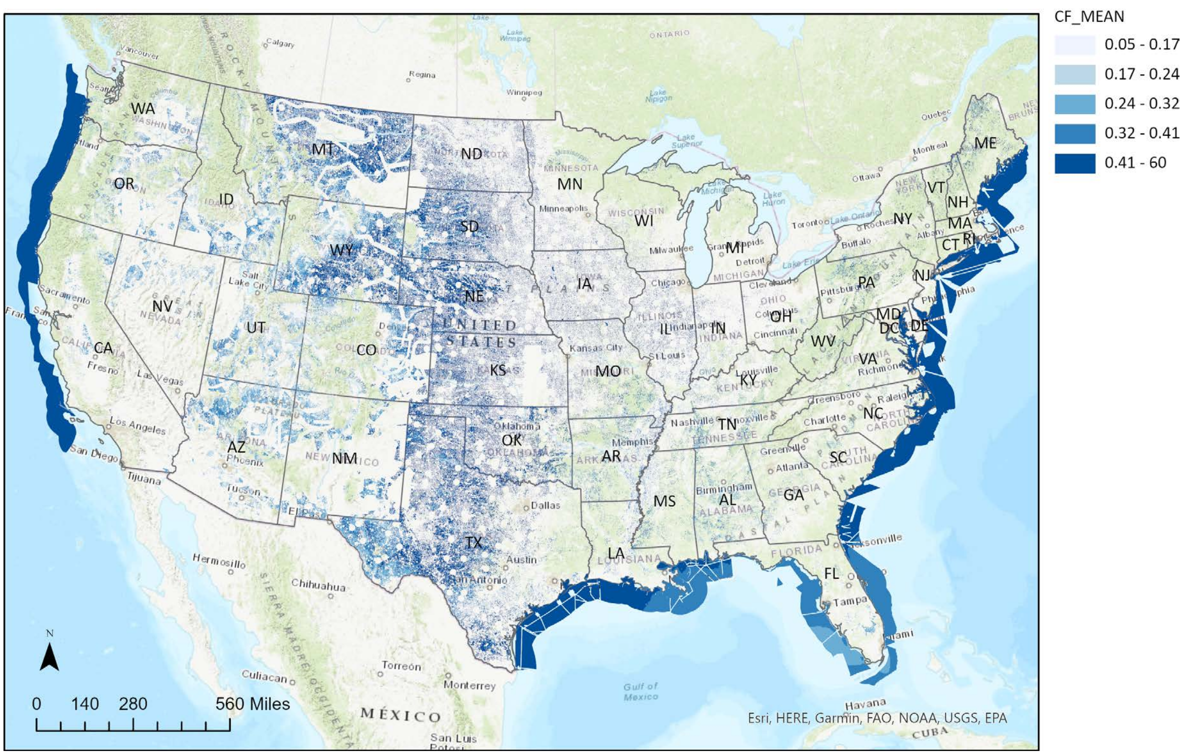
Result: The new model functionality shows economic deployment of both distributed photovoltaics and co-located industrial heat production (solar PV to thermal energy storage) as well as improved behavior of flexible end-use loads like EV charging with respect to distribution system constraints.

Geospatial Modeling

Improvement: Our modeling optimizes the building of renewable generating facilities based on supply curves that rank potential locations for wind and solar by cost of production, based on their resource quality and site suitability, at a fine geographic scale. In our 2021 study, we employed the renewable energy supply curves that are used as inputs to NREL's ReEDS model. For this study, we partnered with Montara Mountain Energy to develop our own renewable energy supply curves instead, updated with the latest setbacks and site feasibility screens, which exclude energy development in different locations for a variety of reasons (for example, national parks, ecologically or culturally sensitive areas, terrain features, proximity to roads, etc.). Among other things, this allows us to better determine the miles of transmission spur line (the interconnection between a wind or solar farm and the high-voltage grid) required for a given project. Figure 5 shows a detailed map of candidate project areas for wind energy across the U.S. These candidate areas are aggregated into bins of similar characteristics within each zone when used in the RIO optimization.

FIGURE 5.

Candidate Wind Projects Across the U.S.



Result: These modeling improvements have several important benefits for the results of this study, including (1) a more accurate representation of project economics; (2) a more accurate representation of land area requirements for solar, wind, and transmission; (3) the ability to create the **Transmission Friction** sensitivity, discussed in the sensitivity section; and (4) the ability to downscale the scenario results to specific locations at a fine geospatial scale. This detailed mapping exercise for potential solar, wind, and transmission siting for all the scenarios in this study will be published in a white paper as part of this project later in 2022.

Non-CO_2 and Land-Sink Modeling

Improvement: Our previous modeling efforts have used exogenously determined emissions reduction pathways for non-CO_2 and land sector greenhouse gas (GHG) emissions. This has led to a set of boundary assumptions for energy and industrial CO_2 scenarios within the overall GHG framework. For example, if by 2050 non-CO_2 emissions are reduced by 50% from today's level, and if the land-sink is increased by 50%, then these emissions would approximately offset one another in CO_2e terms. In this case, if energy and industrial CO_2 reaches net-zero, so do overall U.S. GHG emissions. In the current modeling, we've endogenized non-CO_2 and land sector CO_2, developing supply curves for emissions reductions in both sectors, and also developing a representation of methane emissions from leakage in fossil fuel extraction, processing, and delivery. This modeling advance allows for dynamic sector tradeoffs depending on assumptions made for the energy system, and consequently for economic allocation of reductions across the entire economy.

Result: While the basic logic of the land sink roughly offsetting non-CO_2 emissions has held, most of our new scenarios average a 2050 land-sink of -1100 Mt and remaining non-CO_2 emissions of 900 Mt. In these cases, 200 Mt of energy system emissions are offset by these net negative emissions in economy-wide net-zero scenarios.

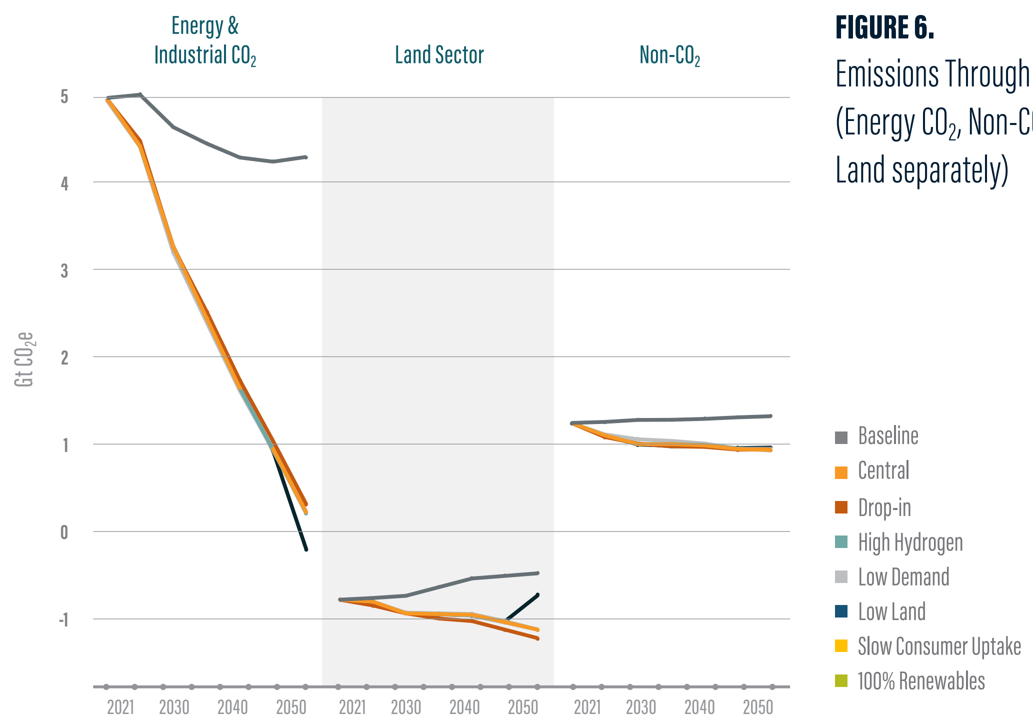


FIGURE 6.

Emissions Through 2050 (Energy CO_2, Non-CO_2, and Land separately)

Air Quality Modeling

Improvement: An entirely new feature in this study is the addition of criteria air pollutant calculations to our modeling, for the purpose of representing the societal cost savings from improved health outcomes attributable to reduced air pollution in each decarbonization scenario. Improvements in air quality over the baseline scenario come from reduced emissions from both point sources, such as electric power plants, and tailpipe emissions from vehicles. This capability was added because the dollar-value savings from the health benefits of improved air quality are so significant—on the same order of magnitude as the cost of investment in decarbonizing the energy system—that to neglect them in a discussion of decarbonization's costs grossly overstates the true cost to society of reaching net-zero.

The EnergyPATHWAYS model now calculates changes over time in $PM_{2.5}$, NO_x, and SO_x emissions from demand technologies, most notably vehicles and building technologies. The RIO model calculates changes in emissions from new and existing power plants. These results are then used to construct Air Quality Scenarios using the EPA's COBRA model, which employs a reduced form air quality model to estimate ambient concentrations of $PM_{2.5}$, NO_x, and SO_x by county. These county-level estimates are translated into health outcomes through concentration-response functions, and then into economic benefits using assumptions about the economic costs of each type of health impact. This allows us to compare the potential range of societal health benefits on a dollar basis across all scenarios.

Result: In every net-zero scenario, we find the societal health savings that result from reduced air pollution are so significant that decarbonization should be seen as a compelling economic proposition on the basis of improved air quality alone. In the central scenario, the range of savings for health impacts is $247B – $553B (COBRA low and high estimates respectively).

IV HIGH-LEVEL RESULTS

The high-level results of this analysis are described below, organized into four sections: energy system decarbonization, infrastructure requirements, costs, and scenario highlights. These results are broadly consistent with those in our 2021 study. Significant new insights that derive from methodological changes, including increased spatial and sectoral resolution in modeling, and from sensitivities that cover a wide range of assumptions about technologies and other critical variables, are discussed in subsequent sections.

TABLE 3. Summary Metrics for Scenarios

Indicator	Units	2021	2050 Baseline	Central	Low Demand	Low Land	High Hydrogen	Slow Consumer Uptake	Drop-In	100% renewables
EMISSIONS										
Gross E&I	Mt	5,327	4,784	1,029	780	1,359	1,133	1,367	1,942	125
Non-CO_2	Mt	1,244	1,321	933	926	943	938	947	937	960
Uncombusted & bunkered CO_2	Mt	-340	-488	-376	-284	-376	-376	-376	-376	-376
Land-sink CO_2	Mt	-795	-490	-1,141	-1,141	-1,141	-1,141	-1,141	-1,240	-740
Geologic sequestration	Mt	0	-4	-449	-285	-790	-559	-802	-1,271	0
Net Emissions CO_2e	Mt	5,436	5,123	-4	-4	-5	-5	-5	-8	-31
Cumulative Net E&I CO_2	Gt	NA	135.9	74.5	73.6	74.5	74.4	74.8	76.3	73.3
CCUS										
E&I CO_2captured	Mt	0	9	620	420	819	706	1,058	1,320	484
E&I CO_2 utilized	Mt	0	5	171	135	29	147	256	49	484
E&I CO_2 sequestered	Mt	0	4	449	285	790	559	802	1,271	0
PRIMARY ENERGY										
Petroleum	EJ	35.5	36.5	8.8	6.4	11.3	9.2	10.9	17.5	0.0
Natural Gas	EJ	32.3	29.6	5.4	4.3	8.4	6.9	8.5	10.1	0.0
Coal	EJ	12.4	6.6	0.1	0.1	0.1	0.1	0.5	0.8	0.0
Biomass	EJ	4.3	4.5	10.3	7.6	9.3	10.5	18.2	18.4	16.3
Nuclear	EJ	8.8	7.9	9.3	8.8	12.0	9.1	10.3	11.4	0.0
Solar	EJ	0.6	5.5	15.9	11.9	18.5	15.8	14.2	10.3	27.7
Wind	EJ	1.4	6.5	22.7	18.5	12.5	23.3	21.7	14.0	30.1
Hydro	EJ	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Geothermal	EJ	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	EJ	96.3	97.9	73.6	58.6	73.2	76.0	85.4	83.6	75.3
FINAL ENERGY DEMAND										
Residential	EJ	12.7	14.1	9.3	7.9	9.3	9.3	10.5	10.5	9.3
Commercial	EJ	9.6	10.9	8.0	7.3	8.0	8.0	8.7	8.7	8.0
Transportation	EJ	25.8	26.1	14.8	10.4	14.8	14.9	18.8	19.5	14.8
Industry	EJ	19.6	25.6	22.1	17.1	22.1	22.5	22.5	22.8	22.1
Total	EJ	67.6	76.6	54.2	42.7	54.2	54.7	60.6	61.5	54.2
ELECTRICITY SHARE OF FINAL ENERGY										
Buildings — Residential	%	46%	55%	87%	87%	87%	87%	72%	72%	87%
Buildings — Commercial	%	50%	54%	90%	90%	90%	90%	74%	74%	90%

Indicator	Units	2021	2050 Baseline	Central	Low Demand	Low Land	High Hydrogen	Slow Consumer Uptake	Drop-In	100% renewables
On-road transport	%	0%	3%	74%	72%	74%	55%	33%	31%	74%
Transport other	%	0%	1%	8%	8%	8%	6%	5%	5%	8%
Industry	%	18%	31%	33%	29%	38%	36%	32%	36%	38%
Total	%	21%	29%	55%	55%	57%	53%	43%	44%	57%
HYDROGEN SHARE OF FINAL ENERGY										
On-road transport	%	0%	0%	17%	19%	17%	36%	6%	0%	17%
Transport other	%	0%	0%	16%	17%	16%	18%	8%	4%	16%
Industry	%	5%	4%	13%	13%	13%	18%	9%	5%	13%
Total	%	1%	2%	10%	10%	10%	15%	5%	2%	10%
ELECTRIC GENERATION										
Total generation	TWh	4,041	5,530	12,112	9,717	10,225	12,195	11,255	8,555	16,493
Thermal capacity factor	%	37.3%	24.6%	4.0%	3.6%	5.6%	3.7%	3.3%	13.2	1.7%
Wind	%	9.4%	32.4%	52.2%	52.9%	33.9%	53.1%	53.6%	45.5	50.7%
Solar	%	4.2%	27.4%	36.5%	34.1%	50.2%	36.0%	35.2%	33.5	46.7%
Hydro	%	7.4%	5.7%	2.8%	3.4%	3.4%	2.8%	3.0%	4.0%	2.1%
Biomass	%	0.7%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%
Biomass w/CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	3.5%	0.0%
Nuclear	%	20.0%	13.0%	7.0%	8.2%	9.8%	6.8%	7.2%	10.4	0.0%
Coal	%	26.8%	9.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Coal w/CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Gas	%	31.4%	11.3%	1.4%	1.3%	2.5%	1.2%	0.8%	1.7%	0.4%
Gas w/ CC	%	0.0%	0.0%	0.1%	0.0%	0.1%	0.0%	0.0%	1.3%	0.0%
HYDROCARBON FUELS										
Total production	EJ	76.3	69.1	17.2	13.5	20.0	18.7	29.5	33.6	14.1
Fossil share production	%	98%	98%	69%	66%	88%	73%	75%	87%	0%
Biomass share production	%	2%	2%	17%	19%	9%	16%	12%	11%	49%
Electric fuel share production	%	0%	0%	15%	15%	2%	12%	13%	2%	51%
Consumed as solid	%	16%	10%	2%	2%	2%	2%	2%	3%	2%
Consumed as liquid	%	44%	51%	64%	63%	55%	59%	68%	66%	77%
Consumed as gas	%	39%	39%	34%	36%	43%	39%	30%	31%	21%

Indicator	Units	2021	2050 Baseline	Central	Low Demand	Low Land	High Hydrogen	Slow Consumer Uptake	Drop-In	100% renewables
COST										
Gross Cost 2050	$B	1,085	1,296	1,532	1,200	1,558	1,608	1,612	1,798	1,678
Decarb net cost 2050	$B	NA	NA	236	NA	262	311	315	501	381
Decarb total net cost NPV	$B	NA	NA	1,866	NA	1,967	2,413	2,995	4,860	2,402
Net AQ health benefits 2050[1]	$B	NA	NA	400	439	398	398	344	324	403
INDICATORS										
US population	Million	335	406	406	406	406	406	406	406	406
Utility wind & solar land use	MHa	2.8	10.3	31.7	26.3	15.6	32.4	30.7	20.2	41
Interregional transmission capacity	GW-kilomiles	52	67	198	154	101	171	170	130	223
Per capita energy use rate	GJ/person	202	189	134	105	134	135	149	152	134
Per capita emissions	t CO_2/person	16.2	12.6	0.0	0.0	0.0	0.0	0.0	0.0	-0.1
US GDP	$T	21.3	40.1	40.1	40.1	40.1	40.1	40.1	40.1	40.1
Net cost as share of GDP	%	NA	NA	0.6%	NA	0.7%	0.8%	0.8%	1.2%	1.0%
Economic energy intensity	MJ/$	4.5	2.4	1.8	1.5	1.8	1.9	2.1	2.1	1.9
Economic emission intensity	kg CO_2/$	0.26	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric emission intensity	g CO_2/kWh	396	138	4	4	8	3	2	-21	0

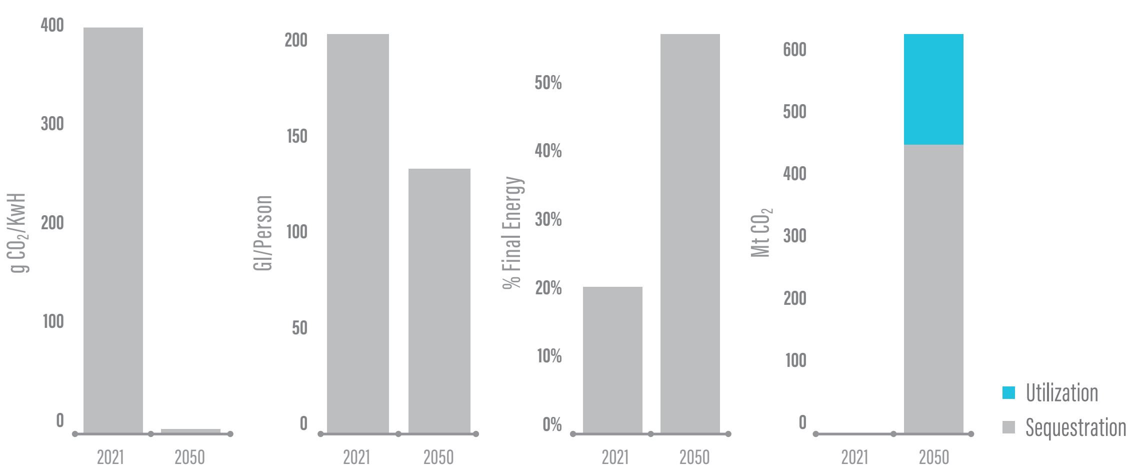
1 Health benefits from air quality (AQ) improvements are reported as an average of high and low cost estimates from the EPA COBRA model.

Energy System Decarbonization

Energy system decarbonization is based on four strategies: using energy more efficiently, decarbonizing electricity, electrifying end uses, and capturing carbon, which is either sequestered geologically or used to make carbon-neutral fuels. Benchmark values for each of these strategies are shown in Figure 1 for the **Central** scenario, in comparison to our energy system today. (1) Energy intensity is one-third lower on a per capita basis and 60% lower on a GDP basis. (2) The carbon intensity of electricity is 99% lower. (3) The electricity share of end use energy is about 55%, or 2.5 times higher. (4) Carbon capture is about 600 Mt CO_2/year, of which 25% is utilized and 75% is geologically sequestered. Current carbon capture is negligible.

FIGURE 7.

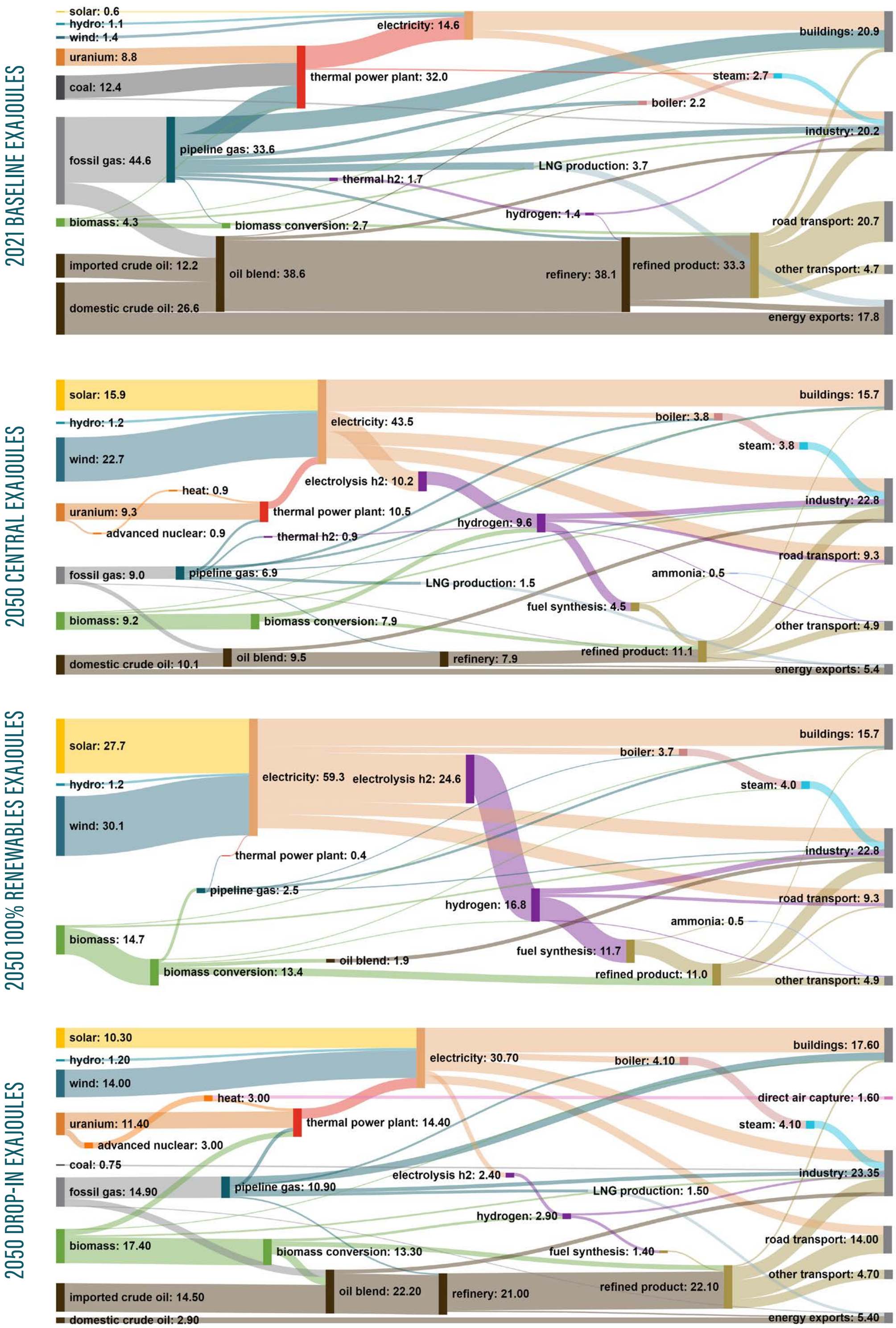
Metrics for the Four Main Strategies of Deep Decarbonization, 2050 Central Scenario Compared to Current Levels.



The energy system transformation resulting from these strategies is illustrated in Figure 2, which contrasts the U.S. energy system in 2021 with three different 2050 net-zero scenarios. In 2021 (Fig. 2a), coal, oil, and natural gas comprise 80% of the primary energy supply, and combustion fuels comprise 80% of final energy consumption. Petroleum refining and thermal power generation are the dominant forms of intermediate energy conversion. By contrast, in all net-zero scenarios, both primary and final energy use are lower than in today's system, as efficiency improvements outpace higher energy service demand due to rising population and GDP. Electrification increases the share of electricity in final energy and reduces the share of combustion fuels, above and beyond the overall decrease in final energy demand. Conversion processes that currently play a minimal role—the production of hydrogen and synthetic fuels from biomass and electricity— become essential components of the net-zero systems. The **Central** scenario (Figure 8b) is book-ended by the **100% Renewables** (Figure 8c) and **Drop-In** (Figure 8d) scenarios, which represent opposite extremes for the residual role of fossil fuels in a net-zero energy system.

FIGURE 8.

Sankey Diagrams for (a) 2021 (b) Central (c) 100% Renewables (d) Drop-In Scenarios. Labeled energy flows are in exajoules.

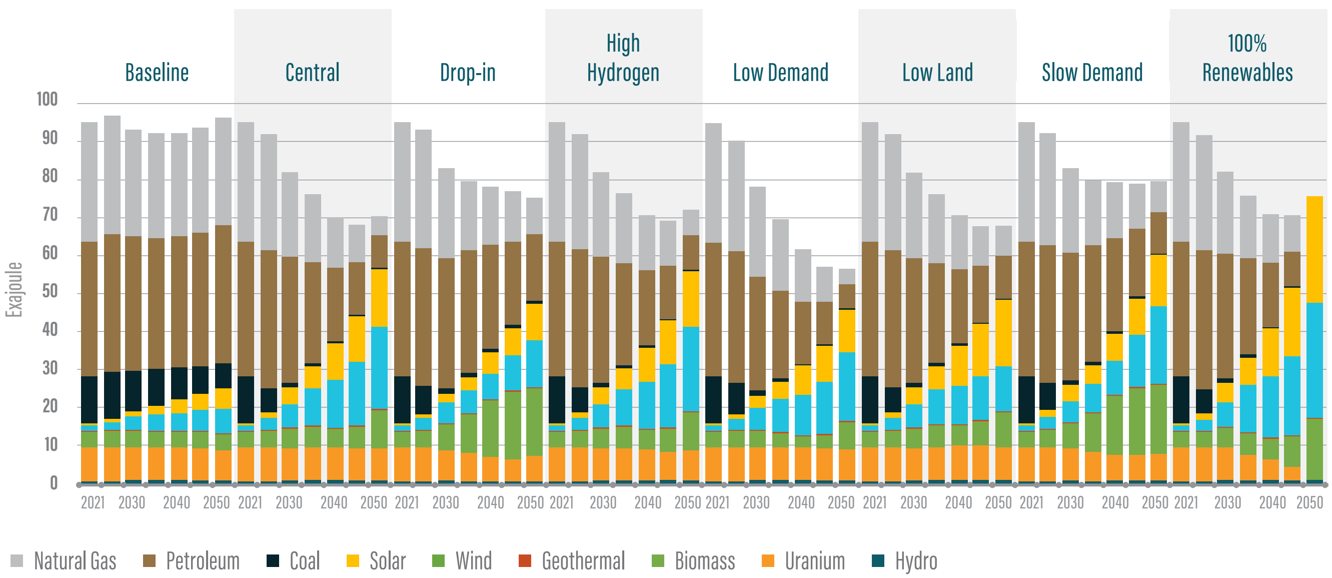


PRIMARY ENERGY

The decarbonization of primary energy is best seen in the decrease in the fossil fuel share and the increase in the renewable energy (primarily wind, solar, and biomass) share. For the **Central** scenario, the fossil fuel share drops below 20%, while the renewable energy share increases to 67% (53% for wind and solar, 12% for biomass). The **Central** scenario is bracketed by the **100% Renewables** scenario, which eliminates fossil fuels altogether and increases the renewable share to 100% (77% for wind and solar, 22% for biomass), and the **Drop-In** scenario, which retains a fossil fuel share of 34% and has a lower renewable share of 52% (29% for wind and solar, 22% for biomass). Total primary energy consumption across all scenarios ranges from 59-85 EJ/y, with 74 EJ/y in the **Central** scenario, compared to 96 EJ/y today. (See Table 1 and Figure 9).

FIGURE 9.

Primary Energy



FINAL ENERGY

Final energy consumption is 54 EJ/y in the **Central** scenario, compared to 68 EJ/y today, a 20% decrease. The electricity share of this consumption rises to 57%, with the remainder met by liquid and gaseous fuels. Across all cases, final energy consumption ranges from 43-62 EJ/y, and the electricity shares range from 43-57%. Lower final energy consumption is correlated with higher electricity shares and vice-versa, since the scenarios with lower electrification rates (**Drop-In** and **Slow Consumer Uptake**) have higher thermodynamic losses from fuel combustion. For similar reasons, the share of the transportation sector (more electrified) in final energy consumption decreases, while that of the industrial sector (less electrified) increases (See Table 1 and Figure 10 & Figure 11).

FIGURE 10.
Final Energy Demand by Type

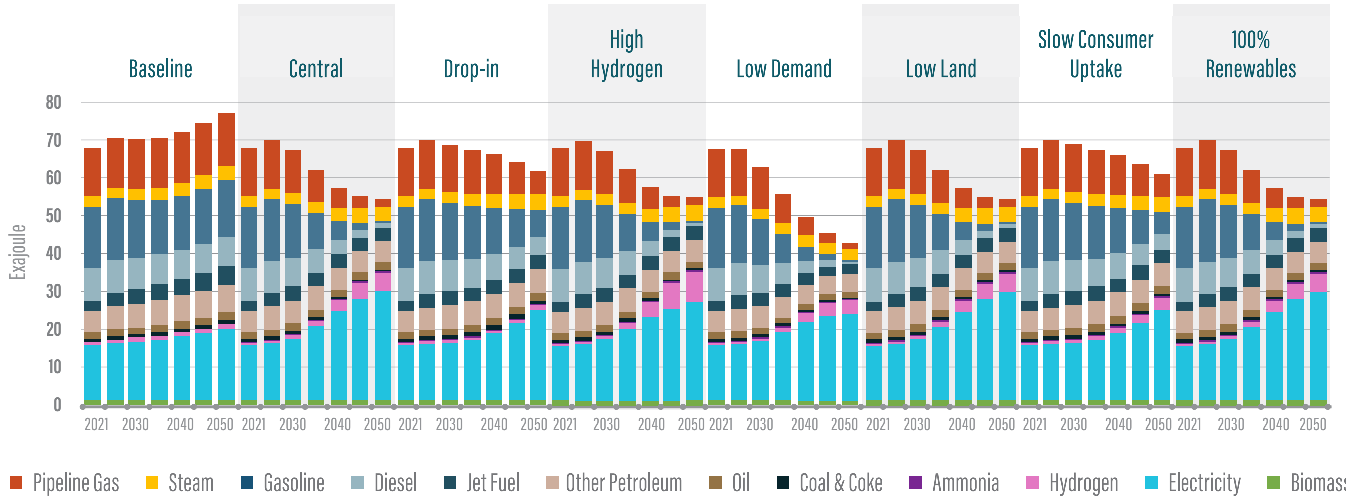
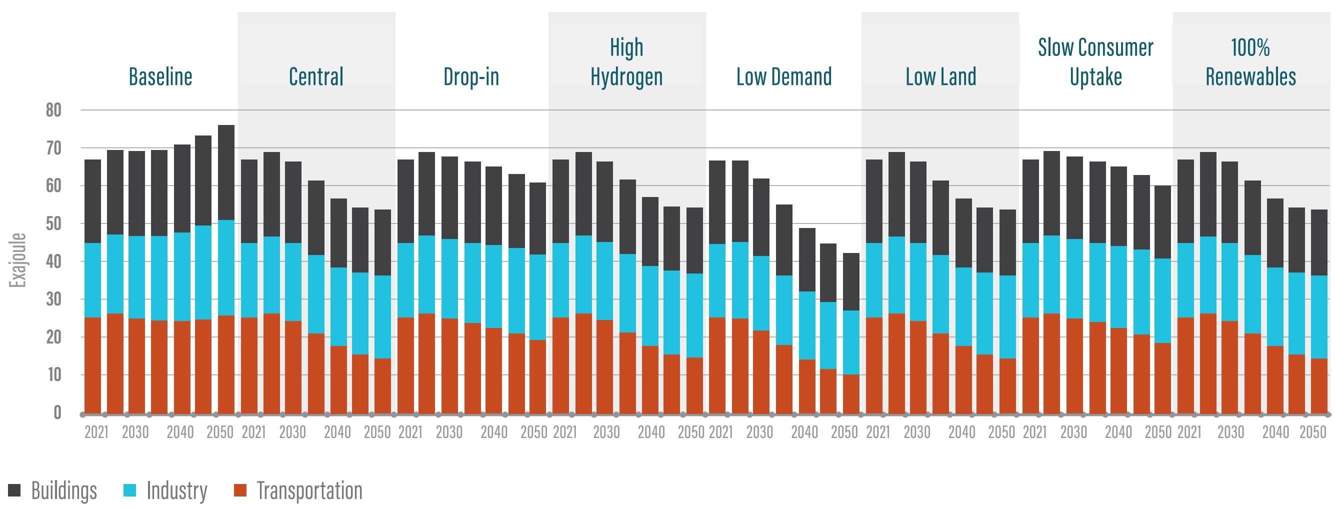


FIGURE 11.
Final Energy Demand by Sector



CCUS

A significant share of remaining fossil fuel consumption in net-zero systems is used for chemical feedstocks, with some of the fossil carbon being sequestered in durable products. Generally, however, the greater the share of fossil fuel in the primary energy supply, the more geological carbon sequestration is required to reach net-zero. In the **Central** scenario, 449 Mt/y of CO_2 is sequestered; the range across cases is zero in the **100% Renewables** scenario to 1271 Mt/y in the **Drop-In** scenario. Even where no carbon is sequestered, it is nonetheless recycled, being captured and utilized in fuel and feedstock production for reasons of economy and carbon budget. In the Central scenario, 620 Mt/y is captured, of which 171 Mt/y is utilized. For the **100% Renewables** scenario, 484 Mt/y is captured, and all of it utilized. For the **Drop-In** scenario, 1320 Mt/y is captured, and 49 Mt/y utilized (See Table 3 and Figure 12 & Figure 13).

FIGURE 12.

Carbon Capture Application

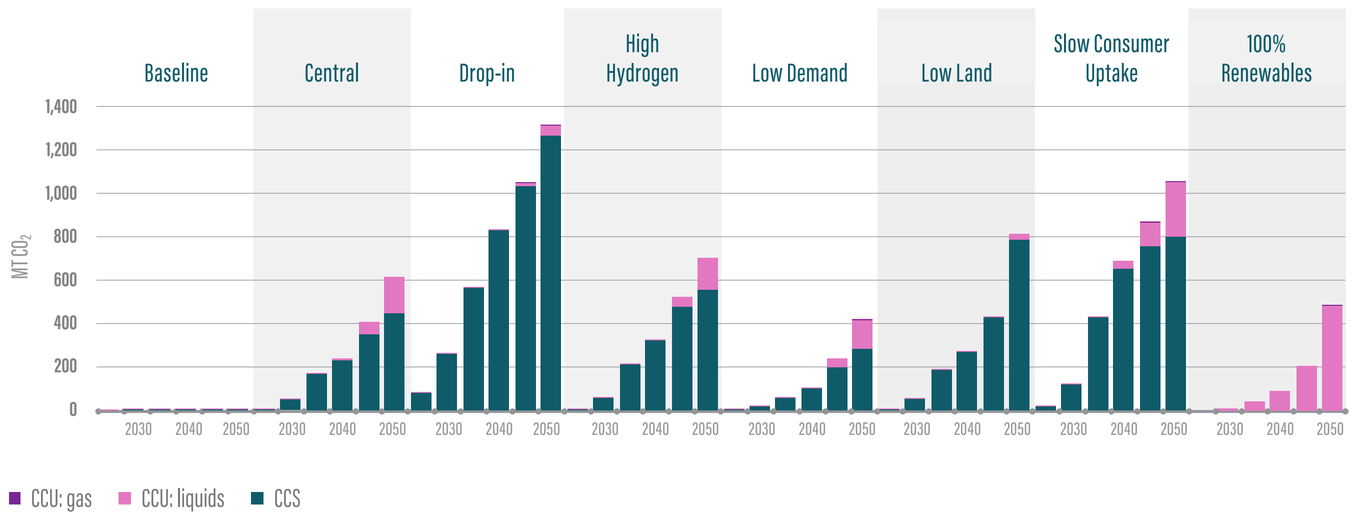
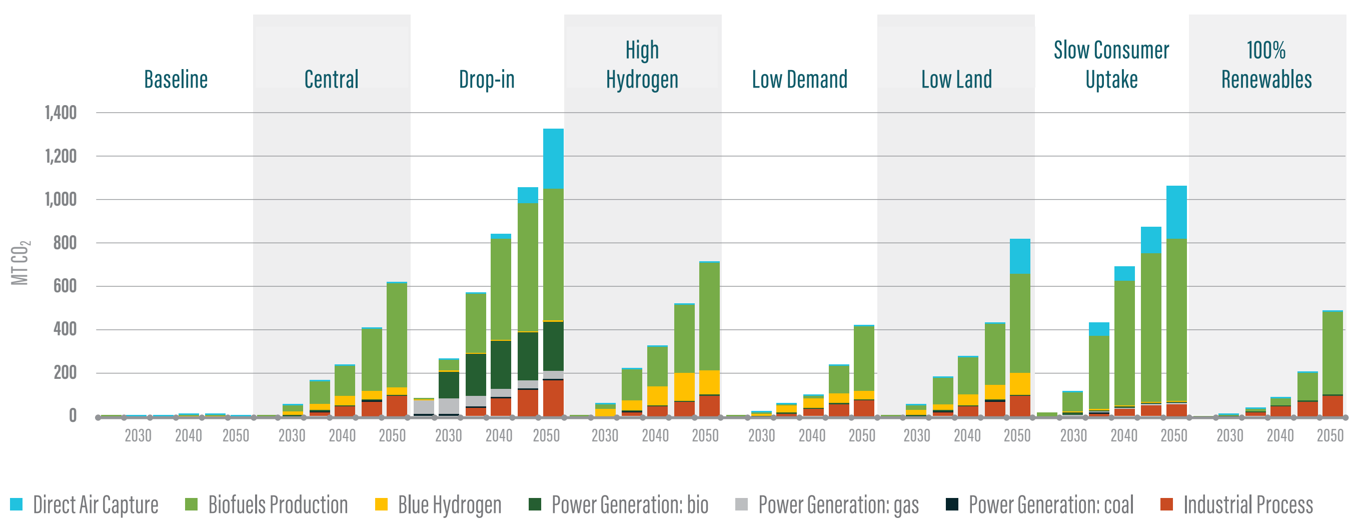


FIGURE 13.

Carbon Capture Source

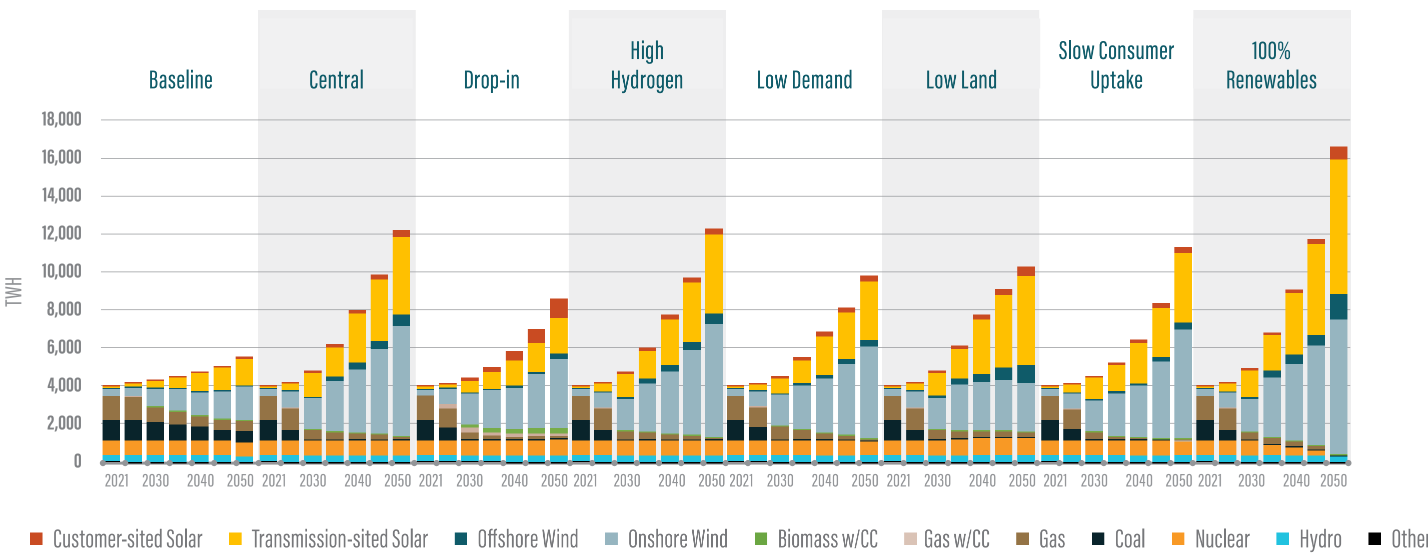


ELECTRICITY GENERATION

Electricity generation is dominated by wind and solar (the least-cost sources of decarbonized bulk energy) in all cases, ranging from 97% (**100% Renewables**) to 75% (**Drop-In**). Nuclear generation totals range from zero (**100% Renewables**) to 1.4x today's generation (**Low Land**). Gas thermal generation — including both natural gas and biogas, with and without carbon capture — is used primarily for system balancing and ranges from 1-3% of the generation mix, with wide regional variations based on resource cost and policy constraints. BECCS (bioenergy with carbon capture) plays a role (4% of generation) only in the **Drop-In** scenario, where it is a source of negative emissions in a scenario with high fossil fuels. (See Table 3 and Figure 14).

FIGURE 14.

Electricity Generation

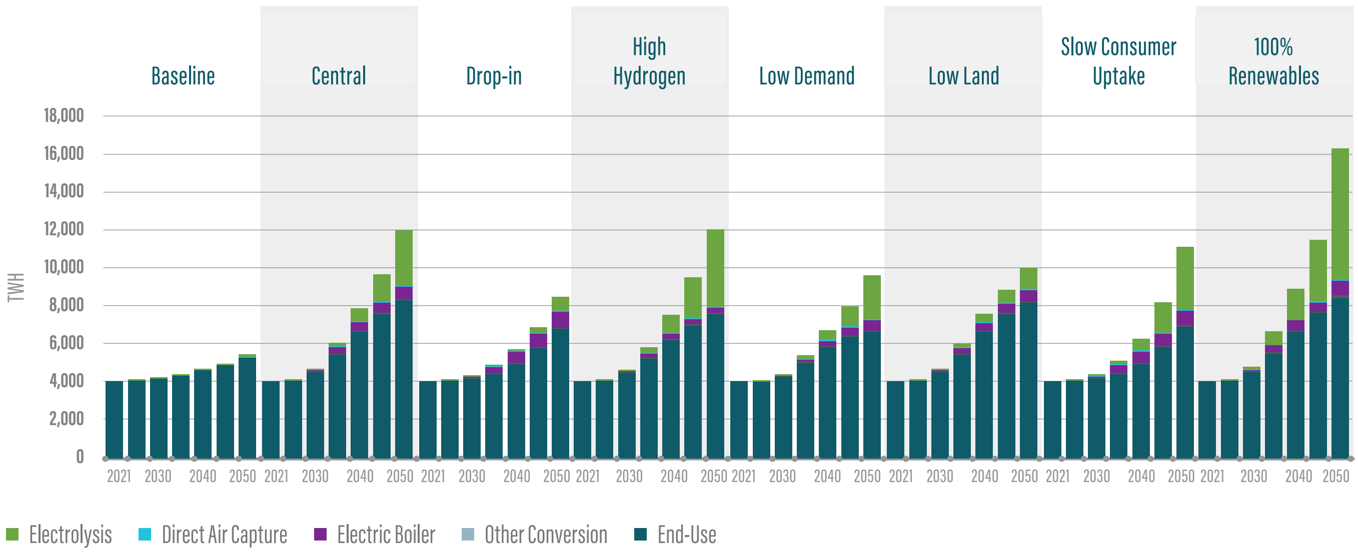


ELECTRIC LOAD

Electric load in net-zero scenarios increases by a factor of two (**Drop-In**) to four (**100% Renewables**). Traditional end-use load is relatively similar across cases, doubling from today's in the high electrification cases, and increasing somewhat less in cases with lower levels of electrification. The main difference in load between scenarios is the amount of electrolysis load for hydrogen production. In the **100% Renewables** scenario, this load is comparable in scale to end-use load, as high production of electric fuels is required to compensate for completely eliminating fossil fuels. In the **Drop-In** scenario, high residual fossil fuel use limits the need for electrolysis and electric fuel production (See Table 1 and Figure 15).

FIGURE 15.

Electric Load



HYDROCARBON FUELS

The combined effect of lower overall final energy demand and increased electrification is to reduce the use of liquid and gaseous hydrocarbon fuels by three-quarters in the **Central** scenario, from 64 EJ today to 17 EJ in 2050. Since electrification rates and fuel strategies are the principal drivers of differences among scenarios, there is a wide range in fuel demand, from 14 EJ in the **100% Renewable** scenario to 34 EJ in the **Drop-In** scenario. The shares of fossil, biogenic, and electric fuels in the fuel mix are also very diverse across cases. In the **Central** scenario, the mix is 69% fossil, 17% biogenic, and 15% electric. In the **100% Renewables** scenario, it is 51% electric and 49% biogenic, while in the **Drop-In** scenario, it is 87% fossil and the remainder mostly biogenic. (See Table 1 and Figure 16).

FIGURE 16.
Fuel Supply

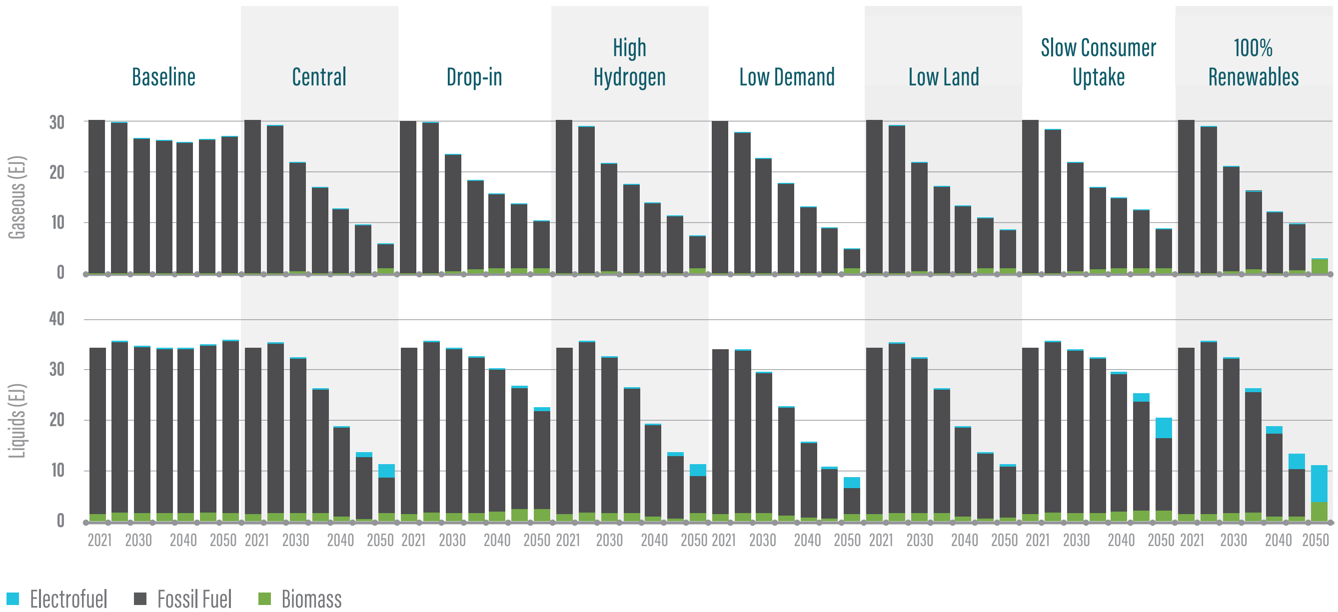
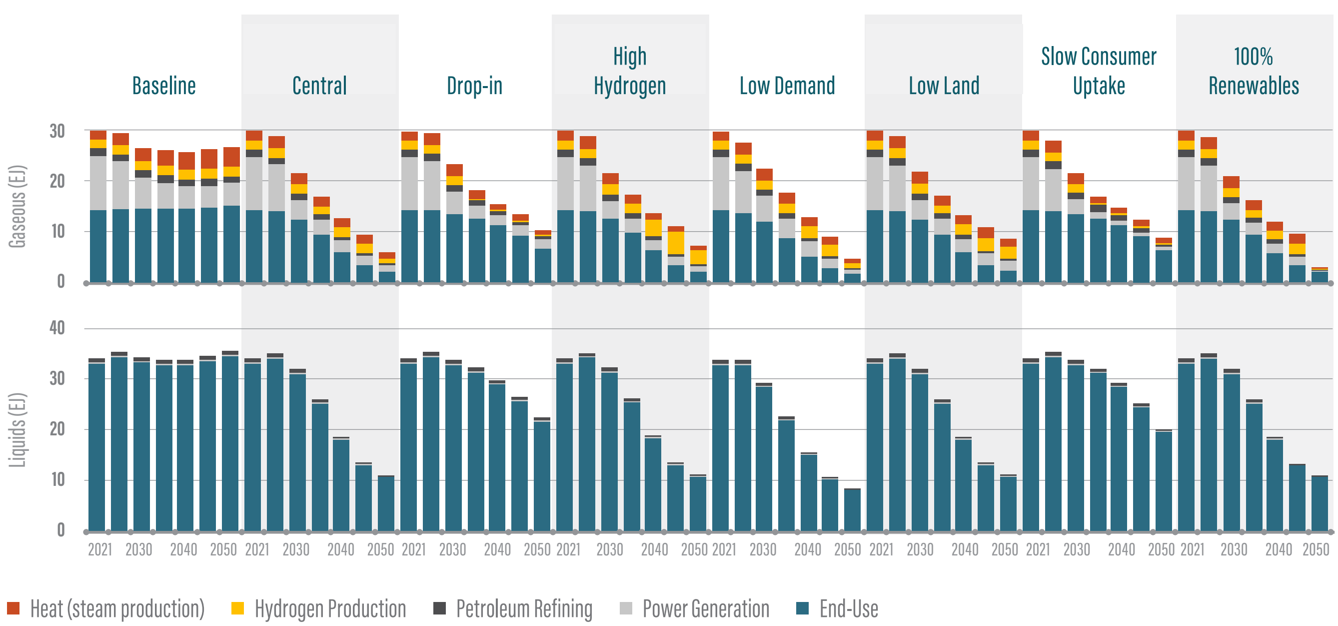


FIGURE 17.
Fuel Demand

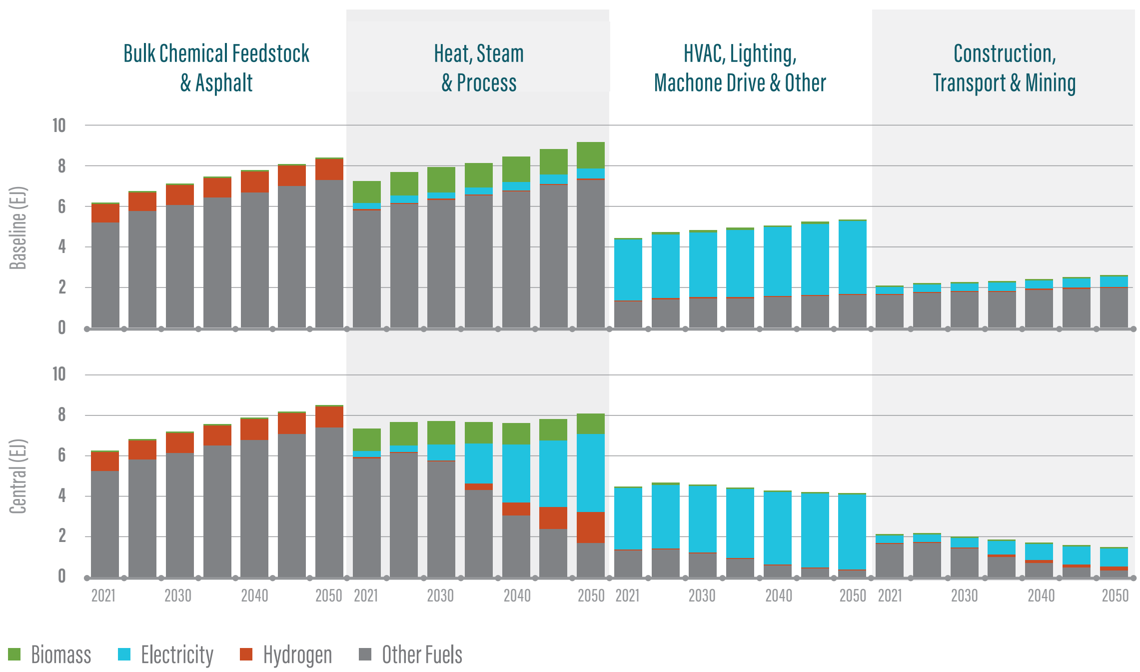


INDUSTRIAL ENERGY

Figure 18 compares demand for industrial fuels in the **Baseline** and **Central** scenarios. These are identical for bulk chemical feedstocks and asphalt, with "other fuels" transitioning from fossil fuel to a portion of fuels being supplied using carbon neutral drop-in alternatives (Figure 16); much of the associated carbon is sequestered in durable products, which in the case of bio-derived alternatives, results in negative emissions. For steam and process heat, in the net-zero case the electricity share increases from 6% to 48% (including all heating loads below 750°C), with another 18% from hydrogen. The electricity share of HVAC, machine drives, and related applications increases from 68% to 90%. In construction, transport, and mining, the efficient electrification of heavy equipment reduces total final energy use, and increases the electricity share from 21% to 65%, with another 15% of 2050 final demand transitioning to hydrogen.

FIGURE 18.

Industrial Energy Demand by Type and Application, Baseline vs Central Scenario



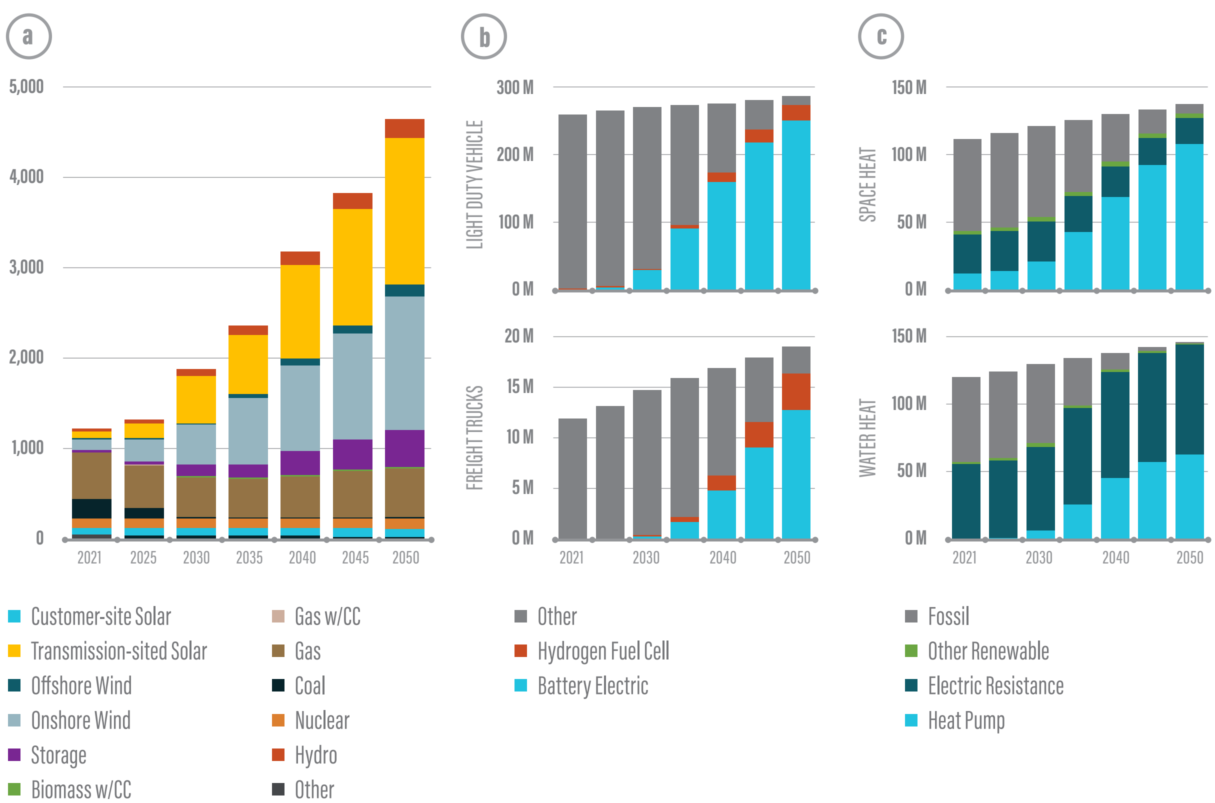
Note: "Other fuels" is final demand for other hydrocarbon fuels, which by 2050 includes drop-in alternatives derived from biomass and electricity. Biomass and electricity are final consumption of woody biomass or electricity directly by industry and does not include their upstream use to create fuels.

Energy Infrastructure

A net-zero energy system is achieved by an infrastructure transition in which high-emitting, low-efficiency, and fuel-consuming technologies are replaced by low-emitting, high-efficiency, and electricity-consuming technologies, at the scale and pace necessary to reach the net-zero target. This is illustrated in Figure 19 for three sectors that together are responsible for two-thirds of current U.S. CO_2 emissions: electric power, vehicles, and buildings. In almost all cases, this transition proceeds by a combination of completely new capacity additions plus the replacement of existing equipment at the end of its normal lifetime, without early retirement.

FIGURE 19.

Infrastructure transition in Central scenario for (a) electricity generating capacity (b) vehicles, and (c) buildings

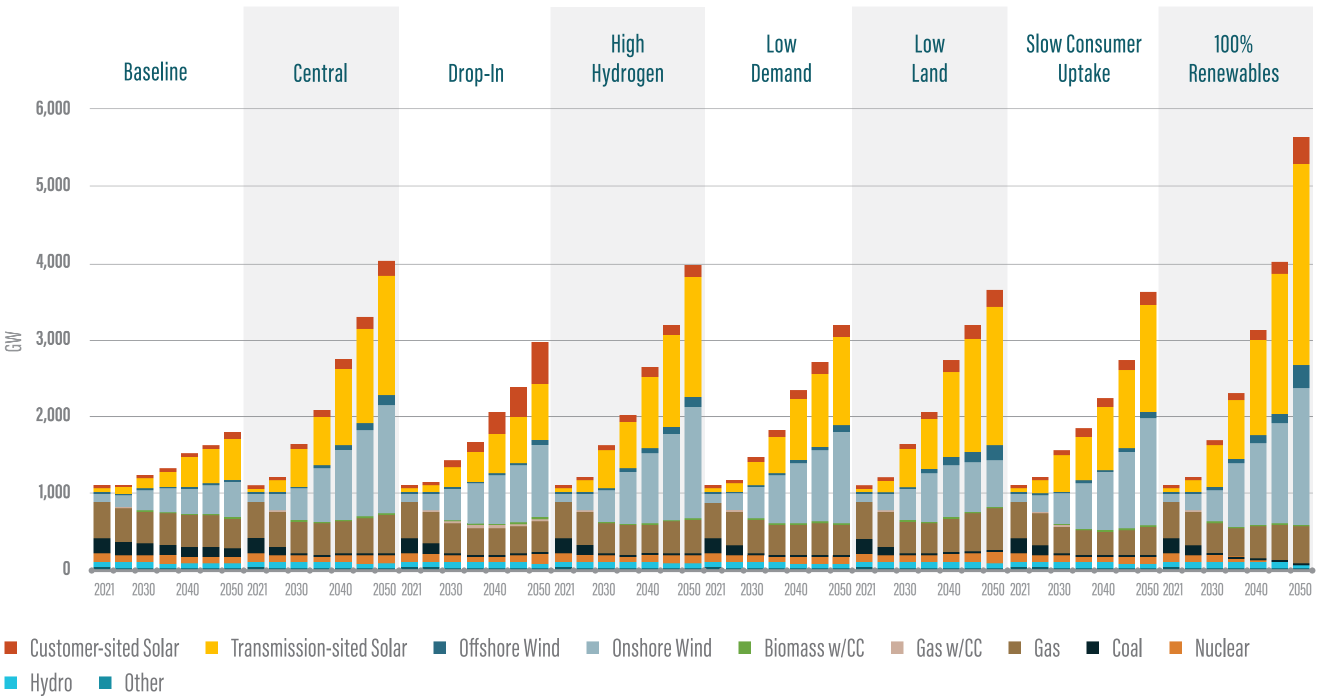


ELECTRICITY GENERATION

In the **Central** scenario, generating capacity increases more than three-fold, with 1298 GW of new wind and 1665 GW of new solar added in the next three decades (Figure 19). Across scenarios, total generating capacity ranges from 3186-6267 GW in 2050, the difference being driven largely by electric fuel production, with new capacity additions of 478-1658 GW of wind and 1189-2885 MW of solar (Figure 20). Among other generation types, the most important is gas thermal capacity ***without*** CCS, with a net reduction up to 105 GW in some scenarios to an increase of 65 GW in others; these units run infrequently but are essential for reliability, especially when supporting high levels of electrification. Nuclear capacity increases by up to 78 GW (**Low Land**).

FIGURE 20.

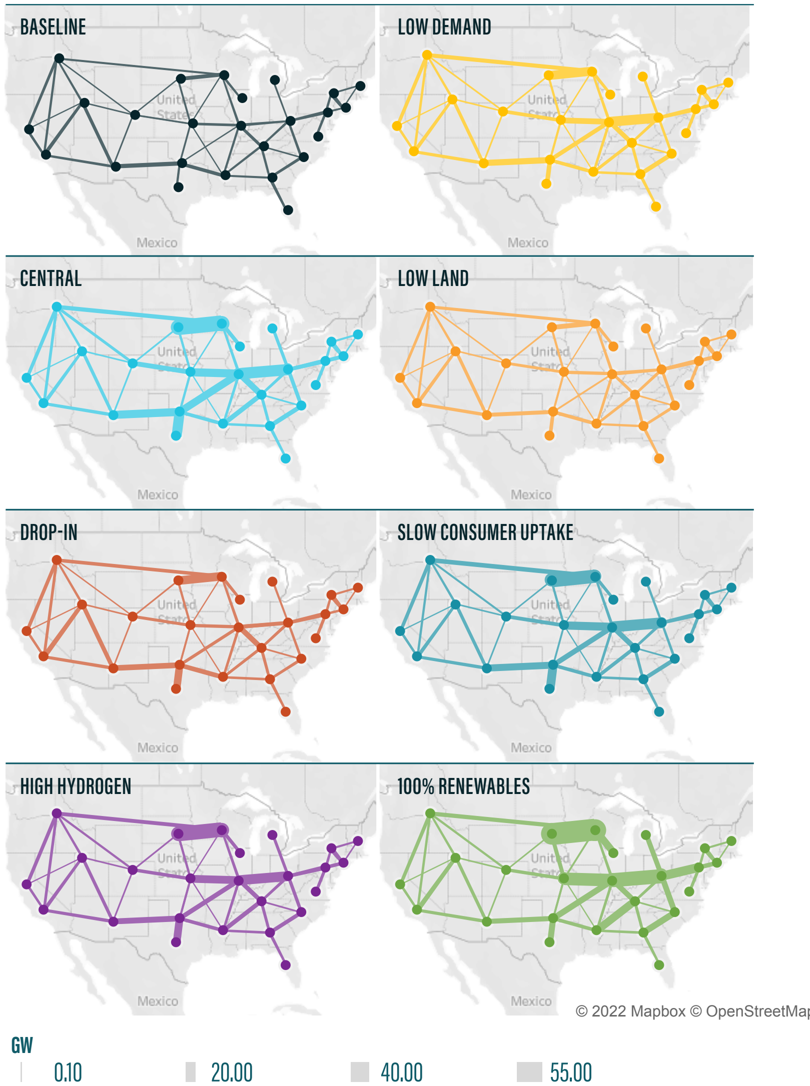
Electricity Generation Capacity



ELECTRIC TRANSMISSION

Long-distance transmission capacity (GW-miles) increases by 280% in the **Central** scenario and 430% in the 100% Renewable scenario (Table 3 and Figure 21). Even in scenarios with restrictions on land use (**Low Land**) or cost penalties on new infrastructure (**Drop-In**), the capacity still nearly doubles from today's level by 2050. This highlights the need for a new approach to building transmission in the U.S., where new capacity is added rarely and in small increments, and the failure to allow sufficient new transmission to be built would likely put net-zero by mid-century out of reach.

FIGURE 21.
2050 Electric Transmission Capacity



VEHICLES

In all high electrification scenarios including the **Central** scenario, more than 87% of the automobile and light truck fleet in 2050 is battery electric vehicles, requiring a cumulative production of more than 349 million EVs by mid-century. In slow electrification scenarios including the **Drop-In** scenario, this is reduced to 56% of the fleet and 195 million vehicles. In high-electrification scenarios, the medium- and heavy-duty truck fleet is 67% battery electric and 19% fuel-cell electric, requiring a cumulative production of more than 19 million electric and fuel-cell trucks by mid-century. In slow electrification scenarios, this is reduced to 32% of the fleet being battery electric, 9% fuel-cell electric, with a cumulative production of 9 million electric and fuel-cell trucks (Figure 19b).

BUILDINGS

Space and water heating constitute the dominant share of fossil fuel uses in existing residential and commercial buildings. In a net-zero transition, furnaces and stoves based on fossil-fuel combustion are mostly replaced by electric heat pumps. In the **Central** scenario, in residential buildings, electric heat pumps constitute 119 million out of 147 million space heating units in 2050, and 88 million out of 153 million water heating units, with electric resistance heaters comprising most of the remainder (Figure 19c). Over the next three decades, the cumulative production of heat pumps for all residential building applications is 251 million units in high electrification scenarios.

HYDROGEN

The scale of hydrogen production is highly variable, with 10 EJ in the **Central** scenario, of which 71% is from electrolysis. Across scenarios it ranges from 17 EJ in the **100% Renewables** scenario, with 97% from electrolysis to less than 3 EJ in the **Drop-In** scenario of which only 55% is from electrolysis. Hydrogen pipeline transmission capacity is 60,000 GW-miles in the **Central** scenario, with less than 8,000 GW-miles in the drop-in case and more than 191,000 GW-miles in the **100% Renewables** scenario (Figure 22 & Figure 23).

FIGURE 22.
Hydrogen Production

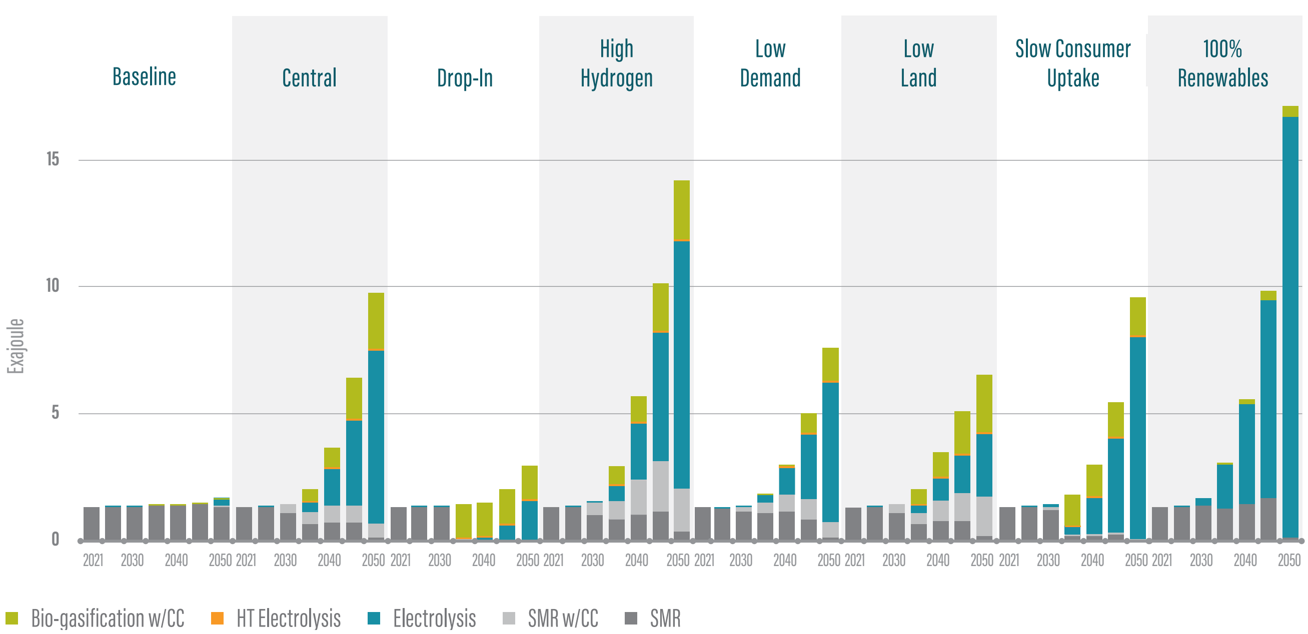


FIGURE 23.
Hydrogen Consumption

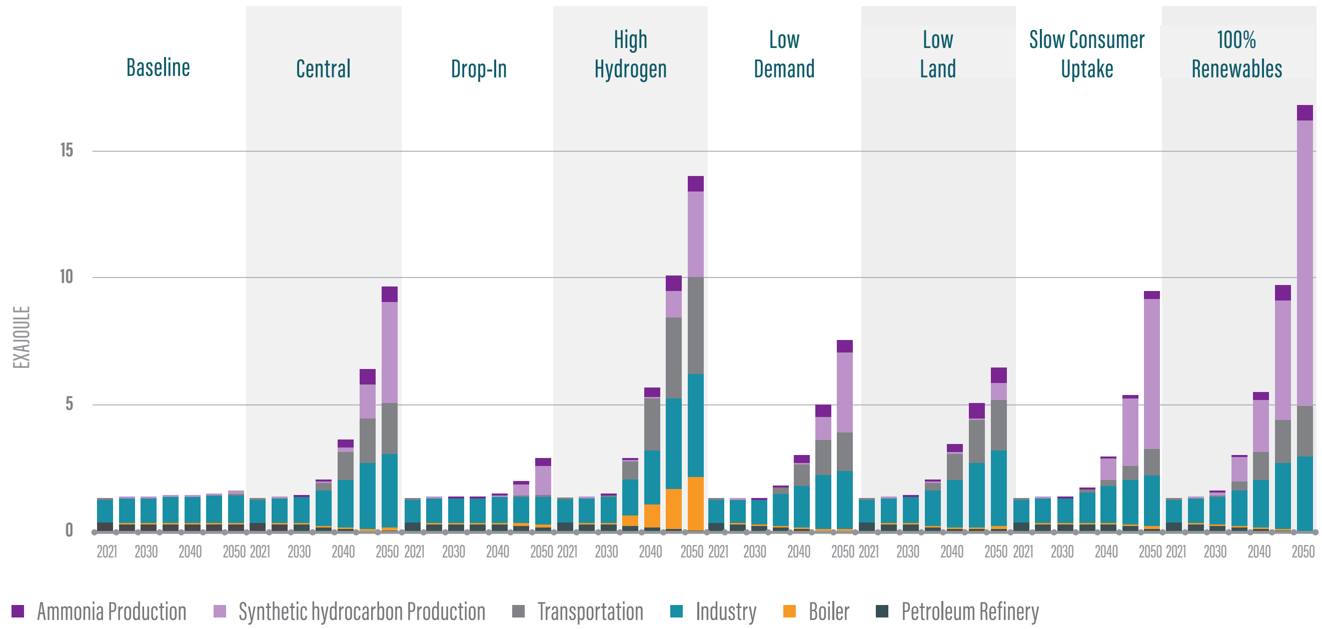
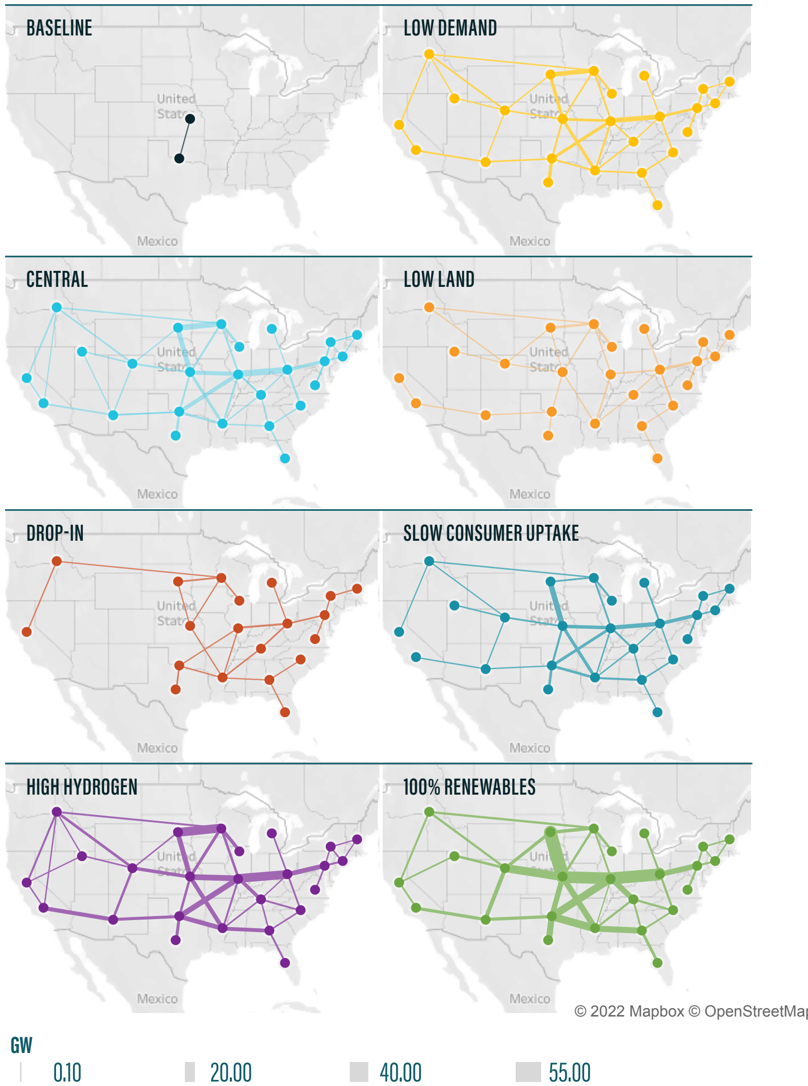


FIGURE 24.
Hydrogen pipeline comparisons between scenarios



STORAGE

Modeled energy storage increases dramatically (though it remains dwarfed by existing fuel storage). By 2050, there is almost 400 GW (3042 GWh) of electric storage in the Central scenario (Figure 25), with a range of 186 GW (1675 GWh) (**Drop-In**) to 638 GW (4891 GWh) (**Low Land**). Across scenarios, >98% of the added electric storage capacity (GW) is short-term battery storage (modeled as Li-ion), and the remainder is long-duration storage. Thermal storage is deployed primarily for the purpose of decarbonizing industrial heat, with 122 GW (527 GWh) deployed in the **Central** scenario. In scenarios with a larger deployment of new nuclear generation, we see a significant amount of thermal energy storage deployed in concert with new reactors (46 GW/267 GWh in the **Drop-In** scenario and 41 GW/233 GWh in the **Low Land** scenario). The largest amount of storage deployed (in energy capacity terms) is in the form of hydrogen storage. This is due to its low cost and its connection to electrolytic hydrogen production, which requires storage when it is being operated on sustained renewable electricity overgeneration.

FIGURE 25.

Total modeled energy capacity (GWh) of storage for all scenarios. Note that the scale of the y-axis changes between storage types

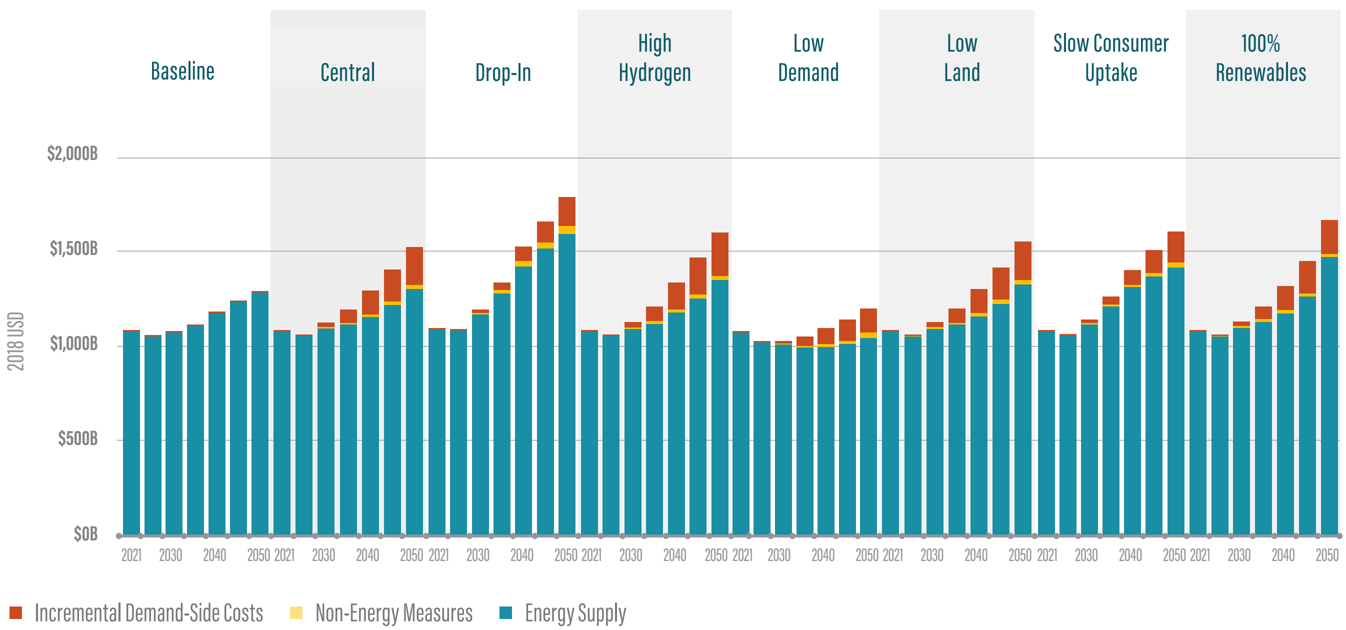
Cost

GROSS COST

The gross annual system cost of the net-zero energy system as well as land sector and non-energy, non-CO_2 mitigation measures is shown across all scenarios in Figure 26. For energy system costs, this is the annualized cost capital and operating cost for both energy supply (electricity and fuels) and energy end-use technologies (in vehicles, buildings, factories, etc.). The gross cost of the **Baseline** scenario in 2050 is 1.30T/y. The lowest cost net-zero scenario in 2050, with one exception, is the **Central** scenario, at $1.53T/y. The lone exception is the **Low Demand** scenario at $1.20T/y, which by definition supplies a lower level of energy services and is therefore not strictly comparable to the other cases (not shown in remaining cost figures for this reason). The **100% Renewables** scenario gross cost is $1.68T/y and the highest cost scenario is the **Drop-In** scenario at $1.8T/y.[2]

FIGURE 26.

Gross Cost of Achieving Net-Zero Greenhouse Gases



NET COST

In comparison to the **Baseline** scenario gross cost of $1.30T/y in 2050, the **Central** scenario has a net cost of $236B/y above that level. This net cost is higher than the $145B estimated for the Central scenario in our 2021 study in *AGU Advances*, with the difference primarily attributable to lower fossil fuel prices in AEO 2022 in comparison to AEO 2019.[3] The main components of this cost difference are shown in Figure 27. In general, the net-zero case has higher capital costs from spending on infrastructure, offset by lower fuel costs relative to the baseline. The **100% Renewables** scenario has a

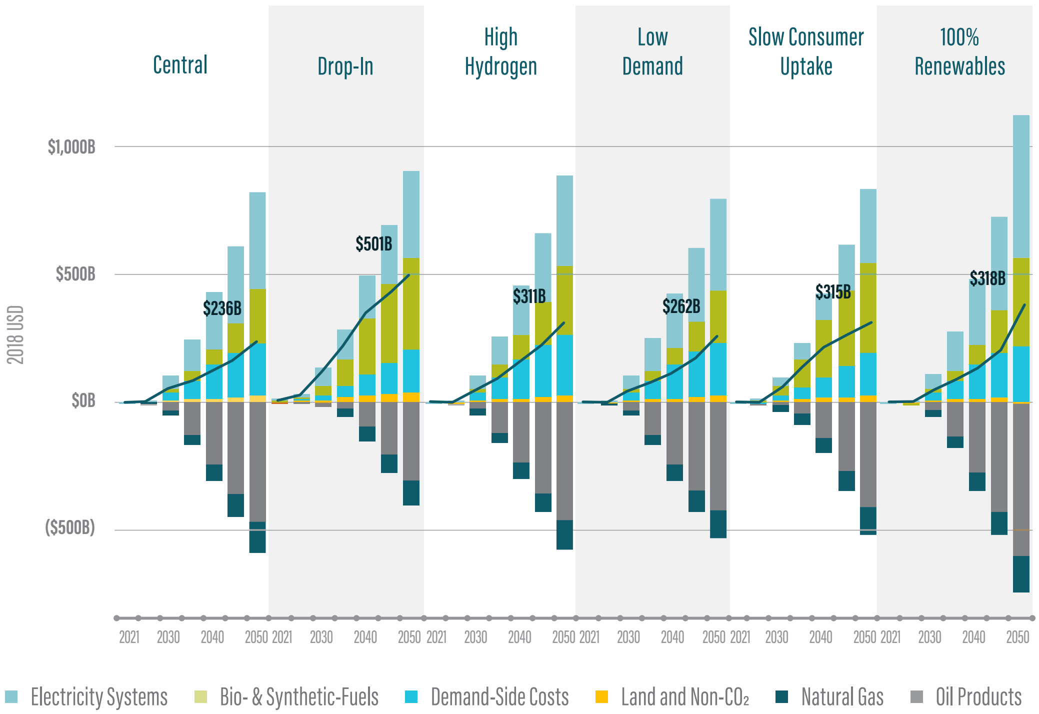
2 We included a cost penalty in the objective of the Drop-in scenario, but the energy system costs were calculated with comparable technology costs to other cases.

3 Lower fossil fuel prices mean that fewer costs are avoided (below the x-axis) from decarbonization. The cost of fossil fuel prices in the counterfactual scenario represents the single largest cost uncertainty for decarbonization.

net cost of $381B/y, and the **Drop-In** scenario has a net cost of $501B/y. The sensitivity of these costs to assumptions about fuel and technology prices is discussed in the sensitivity section.

FIGURE 27.

Net Cost of Achieving Net-Zero Greenhouse Gases. Costs are net of the Baseline scenario and represent the sum of levelized capital costs and variable costs in each modeled year

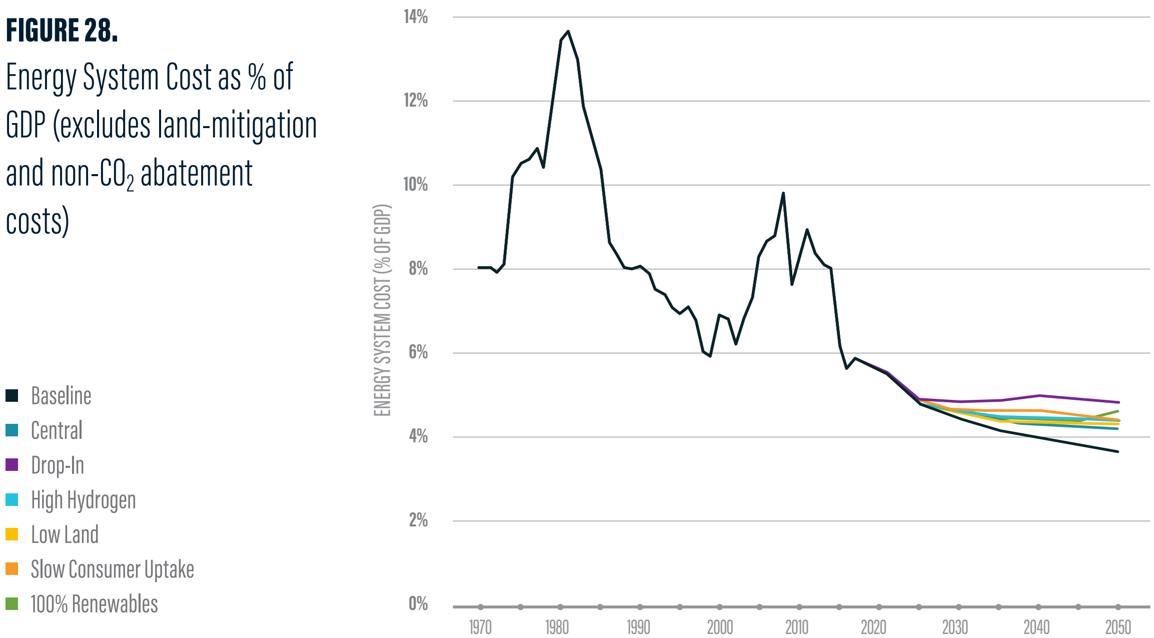


ENERGY COST AND GDP

Figure 28 shows spending on energy for all scenarios in comparison to historical energy costs in the U.S. dating back to 1970. Historical total U.S. spending on energy has ranged between 6% and 14% of GDP from 1970 to the present. In the baseline case, this would decline to 4% in 2050, in line with long-term trends. The net cost of achieving net-zero emissions adds 0.6-1.2% of GDP to energy spending in 2050, with the highest cost scenarios still below the historical range. The share of GDP spent on crude oil and products is lower in all net-zero scenarios than it has been since before 1950, reducing U.S. vulnerability to oil price shocks on the economy of the sort it is currently experiencing.

FIGURE 28.

Energy System Cost as % of GDP (excludes land-mitigation and non-CO_2 abatement costs)



INVESTMENT

Figure 29 shows capital investment in selected clean energy supply technologies during the period 2022-2050. Total investment in electricity generation is $3.4T in the Central scenario, and $2.5-4.9T across scenarios, compared to $0.9T in the Baseline (Table 3); this investment is dominated by wind and solar. Biofuel production, nuclear power, and electricity storage are the next largest investment categories in most scenarios. Importantly, many of the key technologies needed to reach net-zero are not fully commercialized or widely deployed today, such as DAC and electrolysis. The modeled investment levels in Figure 29 are predicated on nth-of-a-kind technology cost forecasts, for example from the NREL Annual Technology Baseline. Upstream investment in R&D and early commercialization is required to attain the market size and price points implied by these levels of investment.

The implications of a major shift in capital flows from fossil fuels to clean technologies are beyond the scope of this study, but represent profound changes in the U.S. macroeconomy, energy security, capital formation requirements, manufacturing opportunities, and labor markets. It also implies significant changes in energy markets themselves. One example is that current electricity markets were not designed for a system in which electricity supply is dominated by generators with zero variable cost. Another is that investment in renewable electricity via power purchase agreements is a very different proposition in terms of risk and cash flow from investing in oil and gas wells.

FIGURE 29.

Capital investment (2022-2050) by Scenario and Technology

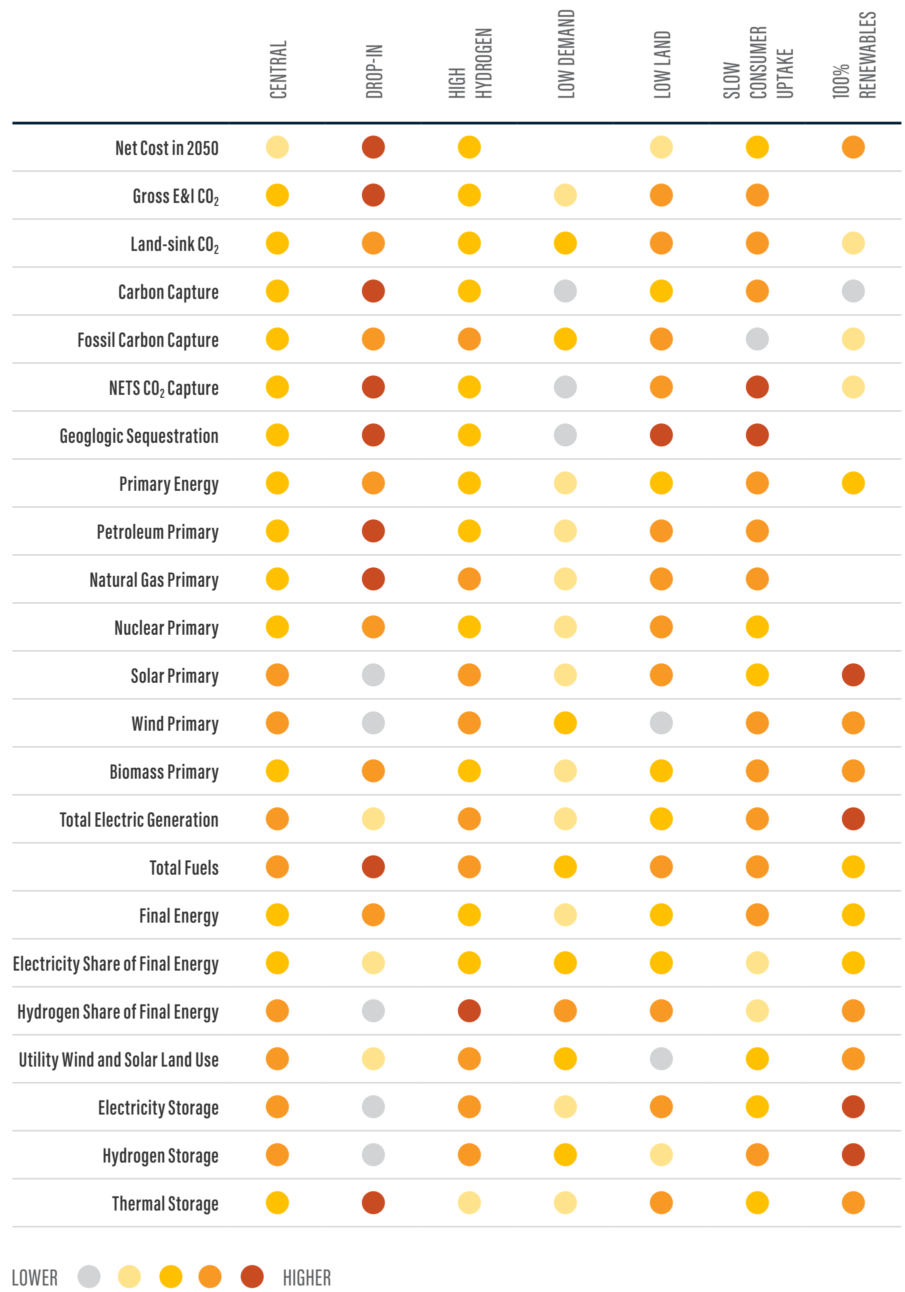
			BASELINE	CENTRAL	DROP-IN	HIGH HYDROGEN	LOW DEMAND	LOW LAND	SLOW CONSUMER UPTAKE	100% RENEWABLES
ELECTRICITY	BECCS Power	$2,000B $1,000B	$0B	$1B	$422B	$1B	$1B	$1B	$15B	$1B
	Electricity Storage	$2,000B $1,000B	$56B	$263B	$204B	$247B	$167B	$399B	$226B	$391B
	Gas Power	$2,000B $1,000B	$77B	$171B	$111B	$140B	$109B	$190B	$76B	$167B
	Gas Power w/CC	$2,000B $1,000B	$0B	$5B	$58B	$3B	$1B	$6B	$3B	$0B
	Nuclear	$2,000B $1,000B	$43B	$97B	$381B	$86B	$68B	$253B	$160B	$2B
	Offshore Wind	$2,000B $1,000B	$24B	$219B	$157B	$212B	$136B	$353B	$134B	$485B
	Onshore Wind	$2,000B $1,000B	$310B	$1,185B	$1,135B	$1,209B	$982B	$596B	$1,138B	$1,488
	Solar	$2,000B $1,000B	$383B	$1,256B	$1,210B	$1,231B	$922B	$1,433B	$1,116B	$2,066B
FUEL & CARBON MANAGEMENT	Biofuels	$2,000B $1,000B	$5B	$528B	$1,352B	$536B	$355B	$492B	$1,157B	$819B
	Blue H_2	$2,000B $1,000B	$0B	$32B	$2B	$91B	$34B	$83B	$5B	
	DAC	$2,000B $1,000B	$0B	$0B	$248B	$0B	$0B	$96B	$150B	$1B
	Decarbonized Steam	$2,000B $1,000B	$7B	$70B	$136B	$62B	$55B	$81B	$71B	$130B
	E-Fuels Synthesis	$2,000B $1,000B	$2B	$76B	$43B	$65B	$59B	$24B	$101B	$185B
	Electrolysis	$2,000B $1,000B	$7B	$156B	$59B	$215B	$123B	$87B	$171B	$405B
	H_2 Storage	$2,000B $1,000B	$1B	$26B	$13B	$27B	$22B	$14B	$31B	$84B

V SCENARIO RESULTS

The highlights of each scenario are compared qualitatively in Table 4 and the subsequent text, to accompany the quantitative values for each metric that are provided in Table 3. The take-home message is that from a technological standpoint there are multiple feasible pathways to net-zero by 2050, at affordable cost, even in cases when some key technologies or resources are limited. However, meeting net-zero under these constraints requires compensating changes in other areas, typically resulting in higher cost and greater use of other technologies or unconstrained resources.

TABLE 4.

Main decarbonization scenario results compared to Central scenario[4]



4 The size of the icons and the color are calculated in comparison to Central scenario values.

Baseline

The **Baseline** scenario is lower cost than all net-zero scenarios except for the **Low Demand** scenario, which provides a lower level of energy services. It does this at the expense of a continuing reliance on fossil fuels as the dominant form of primary energy in the U.S. economy and ongoing emissions of more than 5 Gt CO_2 per year for the indefinite future, with associated climate change, public health, and energy security costs. The greatest changes to the baseline energy system are in the electric power sector, where wind and solar become the dominant form of generation on strictly economic grounds. There is very little transformation of the demand side, as electrification is minimal and almost all end use fuels are fossil. This is not reflective of a current policies scenario that includes IRA, which would see a larger impact from electrification, especially in transportation.

Central

The **Central** scenario is the least constrained and therefore lowest cost net-zero scenario. It dramatically transforms both the supply and demand side of the energy system currently dominated by fossil fuels. Wind, solar, and biomass constitute two-thirds of primary energy by mid-century, and electricity and hydrogen constitute two-thirds of energy end use. Petroleum falls to a quarter of its current level, but does so slowly, with domestic production remaining level until 2035. Electrification and electric fuel production drive a tripling of electricity generation and with it a tripling of the land requirements for wind and solar compared to the **Baseline** scenario.

Drop-In

The **Drop-In** scenario has the highest remaining use of fossil fuels consistent with reaching net-zero, which is achieved through negative emissions that come from the largest increase in the land sink, plus the highest level of carbon capture and geologic sequestration, including the highest levels of power plant BECCS and DAC (negative emissions technology CO_2 capture), across scenarios. This case has the highest final energy demand, the lowest electricity and hydrogen shares of final energy, the lowest electricity generation, the lowest renewable share of generation, the lowest wind and solar capacity, and the second lowest land requirements for wind and solar across scenarios. It also has the highest nuclear share of electricity generation.

High Hydrogen

This case assumes a large proliferation of the infrastructure necessary to deliver hydrogen to end-users. Primary and final energy demand, and electrification share of final energy, are similar to the **Central** scenario. It has a 50% higher share of hydrogen in final energy, including substantially higher direct hydrogen use in transportation (heavy transportation in particular). This case has the second highest level of hydrogen production, electrolysis capacity, and hydrogen pipeline capacity among all scenarios, trailing only the 100% **Renewables** scenario.

Low Demand

This case shows that reducing consumer demand for energy services such as driving and flying lowers the infrastructure requirements of mitigation but does not eliminate the need for large-scale electrification and electricity decarbonization. That said, this scenario has the lowest primary and final energy (both ~20% lower than the Central scenario), along with the lowest electricity generation, fuel demand, carbon capture, interregional transmission, and overall infrastructure build. It also has lower land area and geological sequestration requirements than the **Central** scenario.

Low Land

As a result of limiting the land area available for siting renewables and transmission, this scenario has the second lowest share of renewable generation and the second highest nuclear share among scenarios. It also has the highest share of distributed solar and offshore wind generation. Electric fuel production is the lowest across scenarios due to limited ability to construct high-quality wind and solar. With biomass also limited by land availability, this scenario consequently has the highest fossil share of fuel production and the third highest levels of fossil primary energy and geological carbon sequestration.

Slow Consumer Uptake

Delaying consumer adoption of electrified end-use technologies, and consequently lower economy-wide electrification by mid-century, results in the second lowest electricity share of final energy. This case also has the highest primary energy demand and the second highest levels of final energy demand, fossil fuel end use, biomass use, carbon capture, geologic sequestration, and carbon utilization across the net-zero scenarios. Perhaps counter-intuitively, even with low electrification this scenario required as much electricity generation as the **Central** scenario, due to the need to produce electric fuels for un-electrified end uses. Accordingly, this scenario has similar capacity and land requirements to the **Central** scenario.

100% Renewables

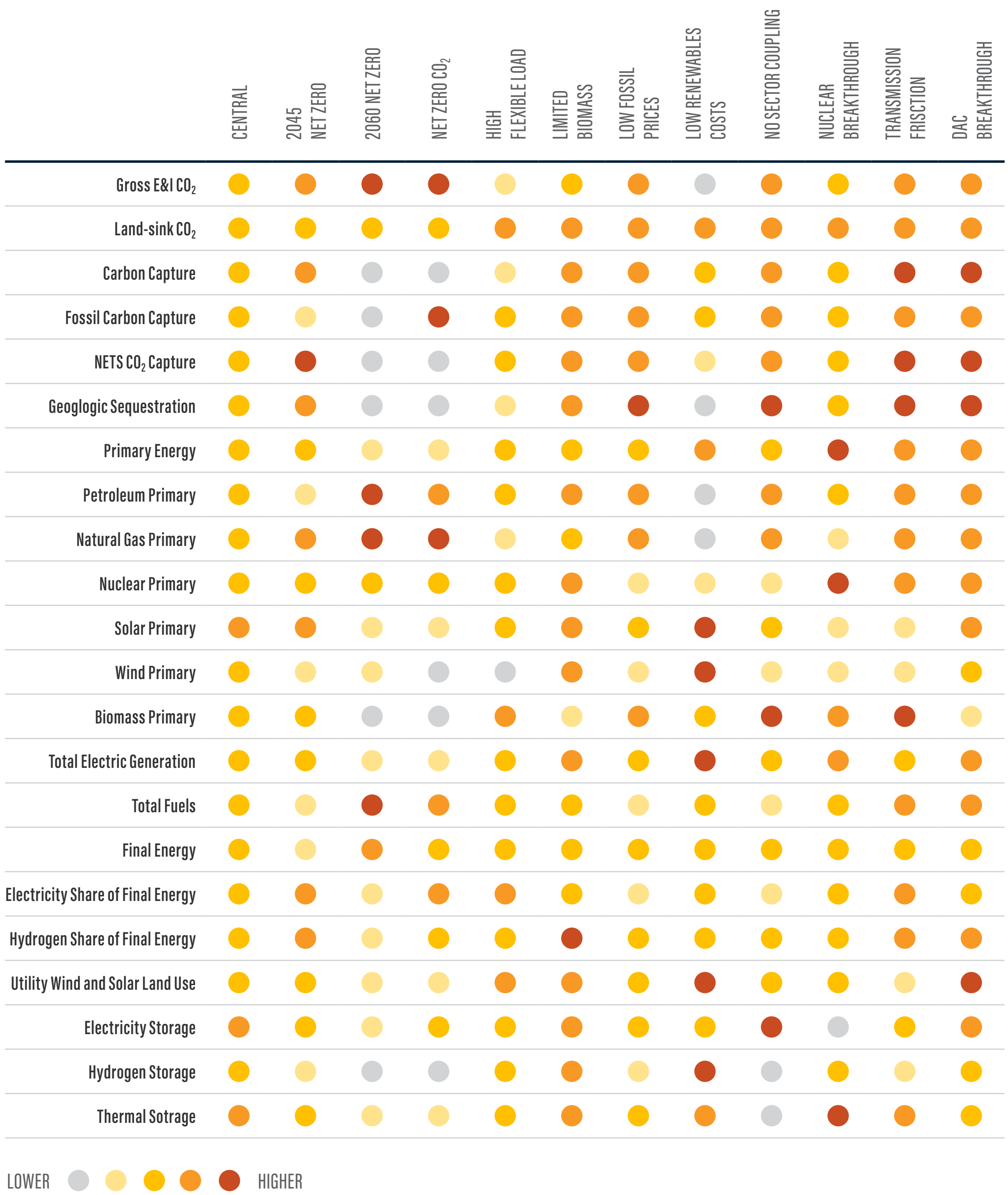
Because this case has no fossil fuels, choices for producing fuels and chemical feedstocks are limited to biomass and electricity. When combined with also having no nuclear power, this case requires the highest level of wind and solar capacity, electricity generation, electric fuel production, electrolysis capacity, interstate transmission, and land area across scenarios. It also has higher biomass use than the **Central** scenario. Although geologic sequestration is not permitted, a relatively large amount of carbon capture is still required to supply the carbon needed for fuel and feedstock production.

VI SENSITIVITY RESULTS

The sensitivity analyses in this study are grouped into two categories. The first explores the effects of changes in key technology costs or deployments (low renewables cost, low fossil fuel prices, nuclear breakthrough, DAC breakthrough, flexible load, sector coupling) or constraints on resources (constrained transmission, limited biomass) relative to the values in the **Central** scenario. The second category considers the effects of changes in emission target scope and timing (CO_2 only, net negative, net-zero 2045, net-zero 2060). The directional impacts on key metrics are shown in Table 5, and the key results for each sensitivity are described below.

TABLE 5.

Sensitivities comparison to Central scenario



Low Renewables Cost

Wind and solar costs consistent with NREL's low long-term cost trajectory significantly reduce the overall cost of reaching net-zero in the **Central** scenario. The main effect is higher deployment of renewables for the production of electric fuels, which double from **Central** scenario levels, with a corresponding reduction in both fossil and biomass derived fuels. Total generation increases by one-quarter, with the renewable share increasing to over 90%. More DAC is deployed due to lower energy costs, but overall carbon capture decreases, and sequestration declines to one-third of the Central scenario level, with most of the captured carbon being utilized. Land requirements for utility-scale wind and solar increase substantially from the **Central** scenario level (23% increase).

Low Fossil Fuel Prices

Fossil fuel prices consistent with DOE's high oil and gas supply price trajectory increase the net cost of the **Central** scenario primarily by reducing the gross cost of the high-fossil **Baseline** scenario. They do not strongly affect the overall net-zero technology deployment, but at the margin they generally have the opposite impact from low renewables costs: decreased electric fuels competitiveness, decreased electrolysis load, and decreased wind and solar primary energy and generation share. There is increased petroleum and natural gas consumption, including gas thermal generation with CCS, and with it increased geological sequestration. This sensitivity has a more modest effect overall on the fossil-renewable balance than the **Drop-In** scenario.

Nuclear Breakthrough

The nuclear breakthrough explored in this sensitivity occurs on two fronts. First, technology improvements lead to a 50% reduction in new reactor capital costs relative to the values assumed in the **Central** scenario. For high-temperature gas reactors, this represents a traditional LCOE reduction (electricity generation at a 95% capacity factor) from $64/MWh to $45/MWh. For small modular reactors, this represents a reduction from $58 to $39/MWh. Second, nuclear technology becomes socially acceptable throughout the U.S., so that plants can be built in areas where the Central scenario does not allow them: California, Hawaii, New England, and the New York metropolitan area. The combined effect of expanding nuclear geography and increasing its economic competitiveness (including direct applications of nuclear heat, as discussed in section 2) is dramatic (Figure 30). By 2050, more than 150 GW of newly built nuclear capacity is added (by comparison, current U.S. nuclear capacity is about 100 GW) and an additional 100+ GW are added as retrofits of existing coal plants. Nuclear generation share triples compared to the Central scenario, maintaining a 20% share of total U.S. generation even as generation itself triples (Figure 31). This also results in a large increase in the amount of thermal storage associated with nuclear heat production to allow for flexible operations. Natural gas use, fuel production, carbon capture, geologic sequestration, and cost all decrease in this case.

FIGURE 30.

New nuclear capacity ($GW_{thermal}$) Nuclear Breakthrough vs. Central

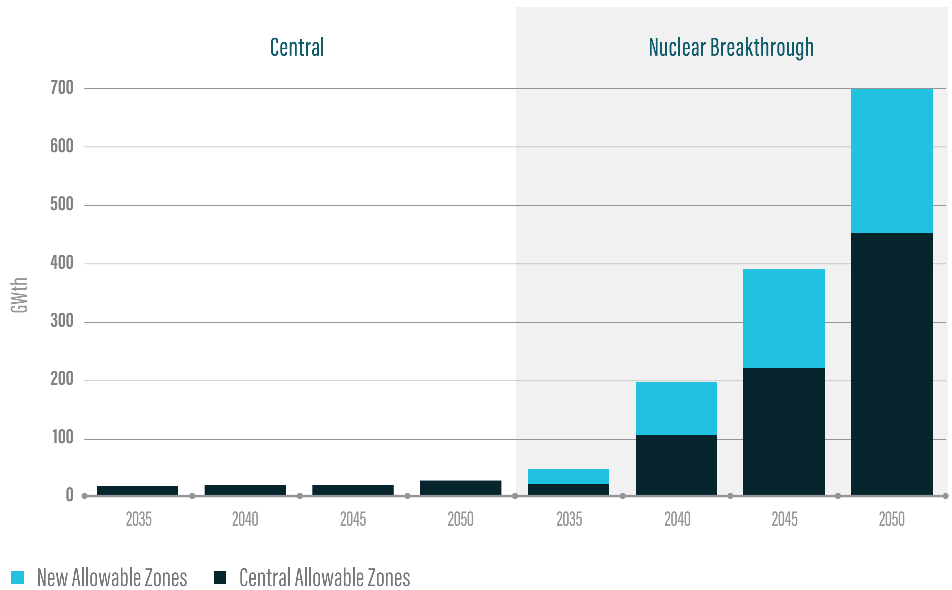
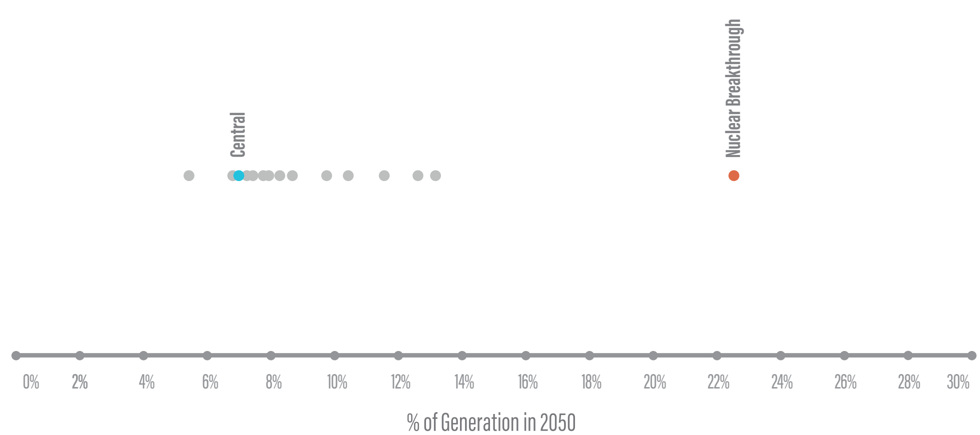


FIGURE 31.

Nuclear generation share in 2050

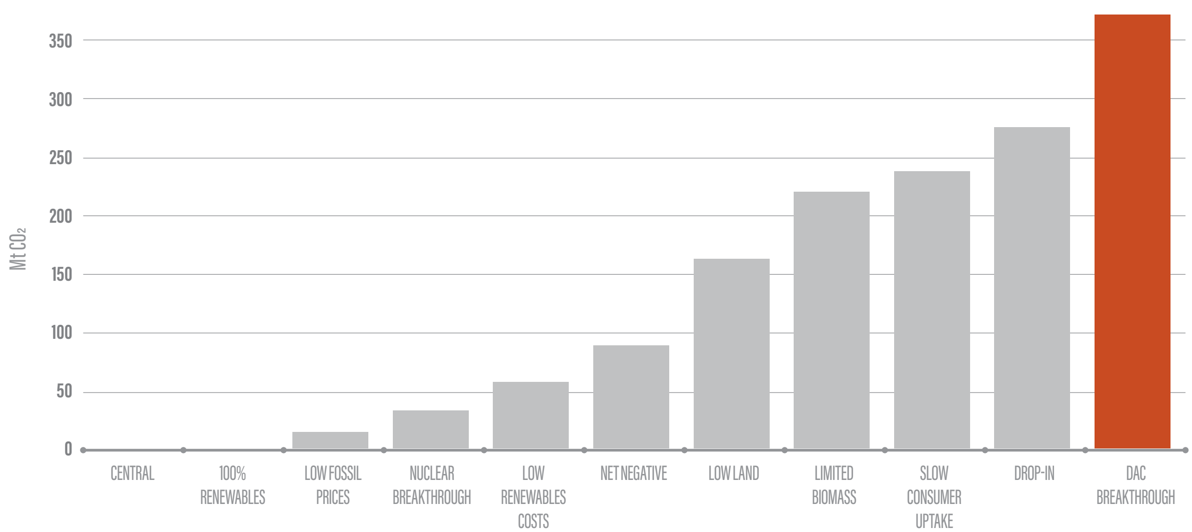


DAC Breakthrough

Decreasing the capital cost of direct air capture (DAC) by 50% (reducing the non-energy costs of capture from $69/tonne to $34/tonne) has several intertwined effects. A large increase in DAC (Figure 32) enables higher levels of carbon capture and geologic sequestration, which are needed to offset greater fossil fuel consumption (especially natural gas) and gross CO_2 emissions. It also leads to a dramatic reduction in biomass consumption, as the cost of supplying carbon-neutral primary energy by using fossil fuel in combination with DAC offsets becomes more competitive with biomass supplies at higher cost levels. The relative cost of fossil fuels and of energy inputs into carbon capture are also factors in this competitive relationship between DAC and biomass.

FIGURE 32.

Direct Air Capture in 2050 by Select Scenarios/Sensitivities



High Flexible Loads

The overall effect of increasing the flexibility of customer end-use loads such as EV charging and HVAC is to reduce the cost of the **Central** scenario, especially costs in the distribution system. By improving load management, it increases the economic deployment of distributed solar PV and significantly reduces grid-scale electricity storage requirements and electric distribution system peaks (on the order of 5-15% compared to the **Central** scenario). Because the shifting of customer loads is typically a short-duration capacity resource, it provides smaller benefits to the bulk power system than sector-coupled industrial flexible loads such as electrolysis.

No Sector Coupling

The effect of eliminating dynamic coupling between the electricity and fuel-supply sectors is that industrial scale loads such as electrolyzers and boilers do not respond flexibly to electricity system conditions as they do in the **Central** scenario but instead operate as conventional non-responsive industrial loads. The lack of coupling increases curtailment (Figure 33) and makes electric fuels much less economic so that they decrease dramatically (Figure 34). In addition, opportunities to decarbonize industrial heat with zero carbon electricity are wasted. The systemic result is that wind and solar primary energy and electricity generation decrease, while biomass use, gas generation, carbon capture, carbon sequestration, and overall costs increase. This case illustrates why sector coupling is critical to the economics of energy systems that are based on high penetrations of renewable energy.

FIGURE 33.
Annual renewable curtailment percentage across all scenarios and sensitivities

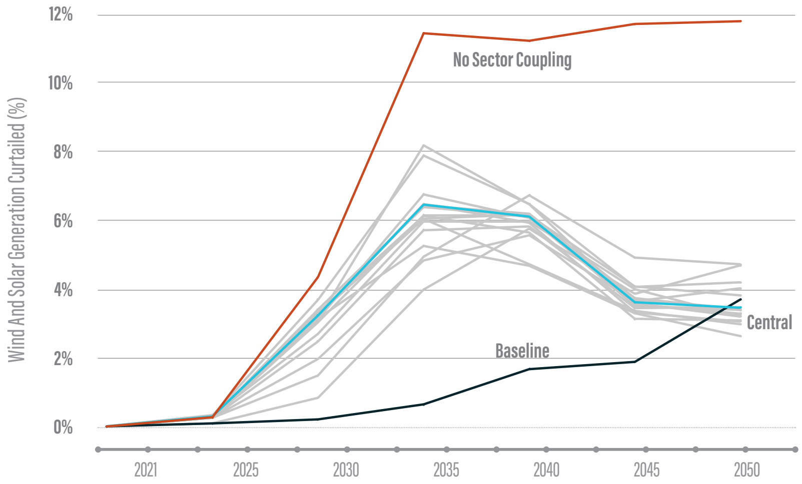
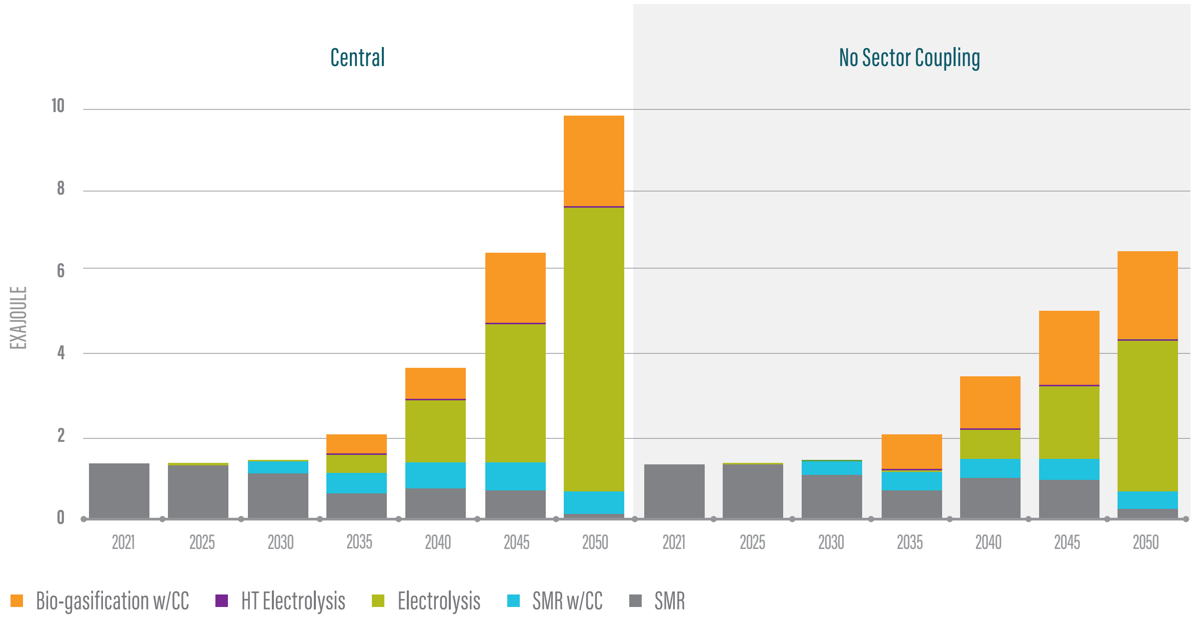


FIGURE 34.

Hydrogen Production Comparison, Central vs. No Sector Coupling

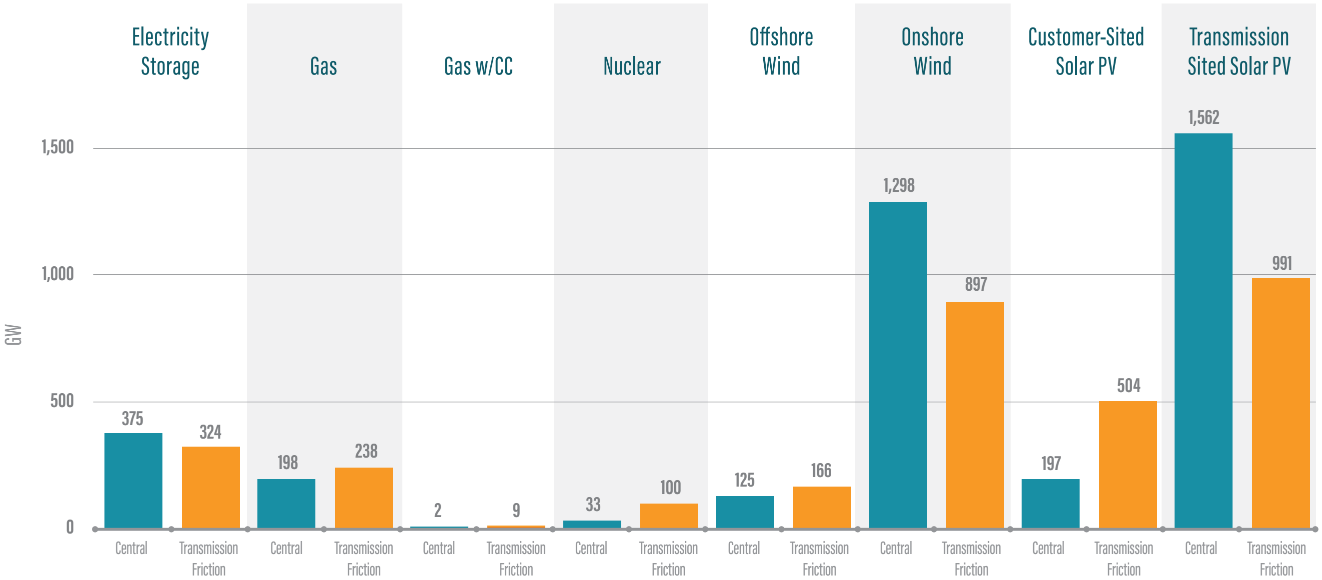


Transmission Friction

Constraining new transmission build to only 50% of the transmission miles added in the **Central** scenario limits access to high quality onshore wind and utility-scale PV sites. This has three main effects. (1) An increase in alternative forms of electricity generating capacity that are less subject to transmission constraints, especially nuclear power (new build increases to 100 GW compared to 35 GW in the **Central** scenario), rooftop PV (increases 2.5 x), offshore wind, and gas thermal generation (Figure 35). (2) A two-thirds reduction in hydrogen and electric fuels production due to less wind and solar primary energy overall. (3) A substantial increase in fossil-based final energy, offset by increased carbon capture and geologic sequestration. These effects are especially pronounced in reducing the flow from the wind belt in the central U.S. to the eastern seaboard (see Figure 36, which compares major transmission corridors in the **Central** and **Transmission Friction** cases). This case has higher overall cost.

FIGURE 35.

Comparison of New Electricity Build to 2050, Central and Transmission Friction



Today the U.S. has approximately 400,000 circuit miles of transmission. The **Transmission Friction** sensitivity explored here increases this total by 60%, which, even though only equivalent to half the transmission built in the **Central** scenario, still amounts to an unprecedented rate of new transmission build in the U.S. compared to recent years. Note also that due to the nature of optimization modeling, using the **Transmission Friction** assumptions the model eliminates the least valuable 50% of transmission, in contrast to real-world transmission friction which eliminates the average line rather than the least valuable line. For this reason, the **Transmission Friction** sensitivity likely underestimates the effects of strongly constraining transmission build.

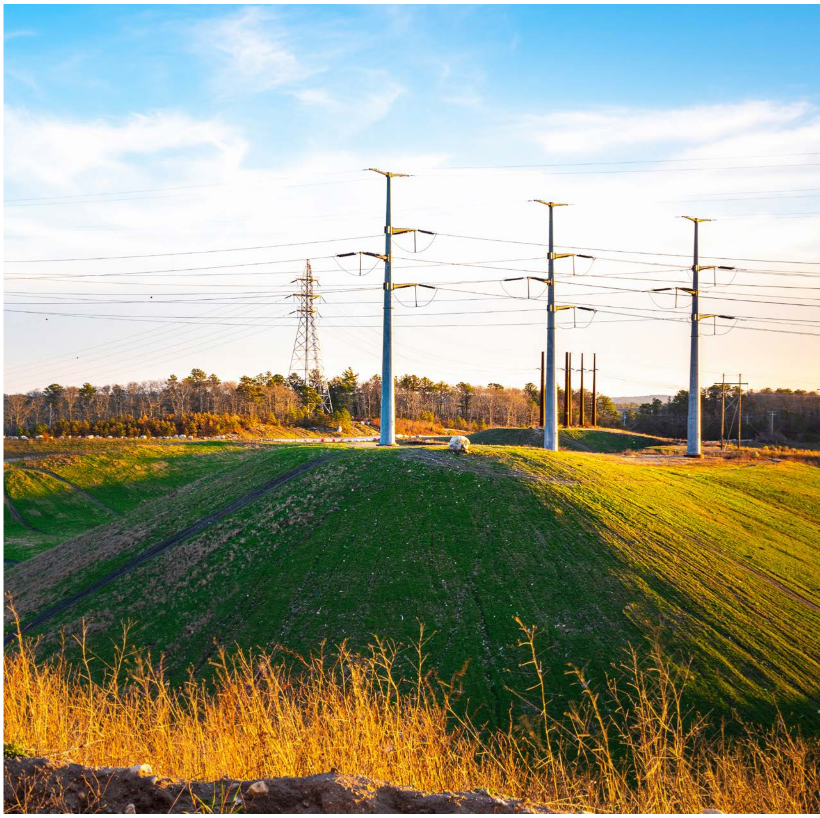
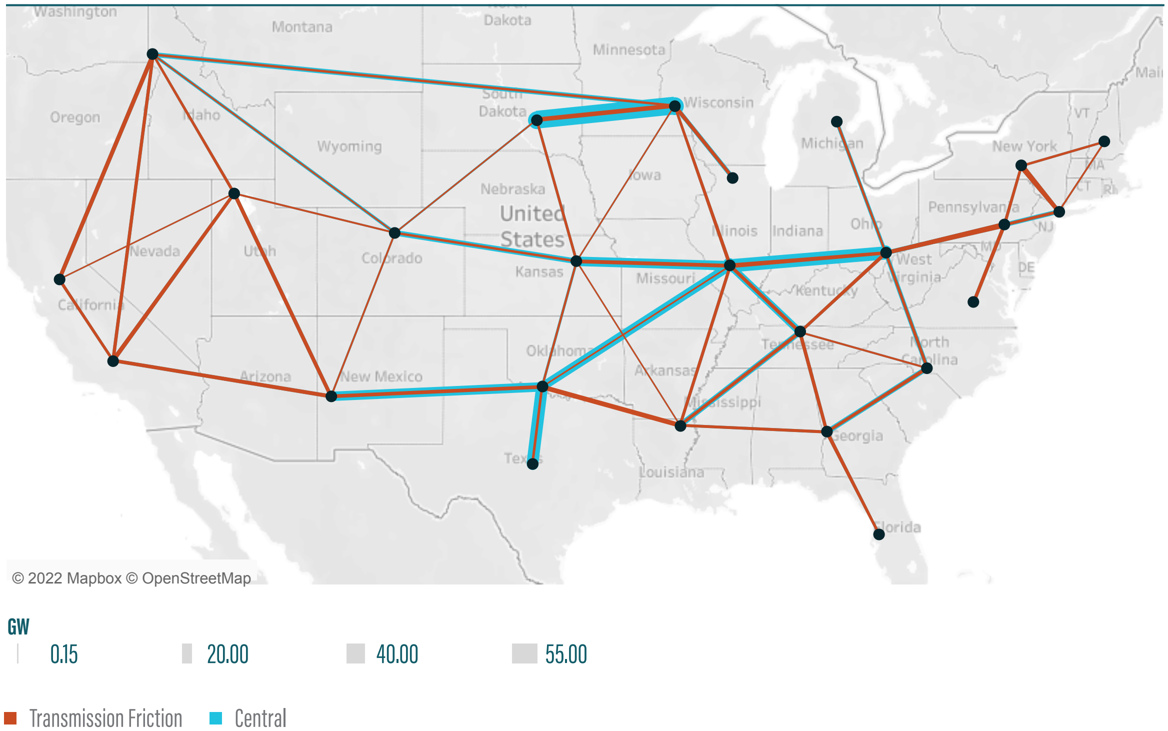


FIGURE 36.

2050 Electric Transmission Capacity, Central vs. Transmission Friction



Limited Biomass

Constraining biomass to remove all purpose-grown energy crops (woody and herbaceous) leads to a 30% reduction in primary biomass and biomass fuel production, a compensating increase in the fossil and electric shares of fuel production, and along with the former higher DAC capacity, carbon capture, and geologic sequestration. Overall cost increases, but the effect is smaller than might have been expected from earlier studies. Across pathways the amount of biomass used is lower than in prior work. This has been a consistent trend now for most of a decade starting with the 2014 Deep Decarbonization Pathways Project report *Pathways to Deep Decarbonization in the United States*, which used 18.5 EJ of biomass in all scenarios despite having a higher economy-wide emissions budget of 750 Mt in 2050. The 2021 *Carbon Neutral Pathways in the United States* study used 12.2 EJ of biomass in the central case and no decarbonization scenario consumed less than 10.3 EJ. The 2022 update uses 9.2 EJ of biomass in the central case, with some scenarios consuming as little as 6.2 EJ (less than a 50% increase compared to today's biomass use).

This decline in biomass use is for several primary reasons: (1) fuel switching in transportation and buildings has undergone tremendous progress over time, increasing the feasibility of such pathways and decreasing the ongoing use of hydrocarbons in these applications; (2) progress in modeling industrial decarbonization has meant that we have a better understanding of where energy goes in industry and what solutions are available; (3) forecasts for the costs of renewables (the primary energy behind electricity-derived fuels) and complementary technologies such as direct air capture have decreased, while those for biomass cost have not.

Net-Zero CO_2-Only

Reducing only CO_2 to net-zero by 2050 and ignoring non-CO_2 greenhouse gases is much less challenging than achieving net-zero CO_2e, comparable to earlier "80 x 50" cases that aimed to reduce emissions to 80% below 1990 levels by 2050. With gross CO_2 emissions offset by negative emissions of 1.1 Gt from the land sink, the main effect of this change in target definition is much more limited production of zero-carbon fuels and much more limited need for carbon management. Electrification rates and the generation mix are similar to the **Central** scenario, but fossil primary energy use is almost doubled, and 95% of end use fuels are fossil-derived. Due to the CO_2-only definition and the land sink offset, geologic sequestration is very limited. The much lower cost of mitigation in this case is illustrated by the shadow price of CO_2 in 2050, where the shadow price in 2050 is $129/tonne in the **Central** scenario and only $78/tonne in the **Net-Zero CO_2-Only** sensitivity. A key point of this exercise is to illustrate the potential pitfalls of failing to rigorously define "net-zero" for purposes of policy and planning.

Net Negative

The net negative case reaches net GHG emissions of -500 Mt CO_2e in 2050, consistent with the emissions trajectory some scientists consider necessary to reduce global warming below 1°C by 2100. It achieves this with the same demand side measures as the **Central** scenario (electrification rates, efficiency improvements) and some relatively small advances in energy supply decarbonization (higher renewables, less fossil fuel, more electric fuels). The main source of reductions is a large increase in negative emissions in the form of DAC and BECCS, resulting in roughly 50% increases in biomass consumption, carbon capture, and geologic sequestration.

Net-Zero by 2045

Achieving net-zero by 2045 and maintaining it thereafter saves about 8 Gt CO_2e of cumulative emissions in this century relative to the **Central** scenario at an incremental present value cost of $558B ($71/tonne average). Advancing the net-zero target year to 2045 results in the same energy system technology and infrastructure and annual costs as the **Central** scenario but requires accelerated deployment. The case highlights the associated challenges, such as more rapid (but not deeper) electrification, faster (but not more extensive) renewable buildout, and earlier development and deployment of (but not greater application of) electric fuels and carbon management technologies. The value of the 2045 target in this study is to provide a numerical benchmark that can help in assessing the feasibility of given rates of decarbonization and weighing these against the value of lower cumulative emissions.

Net-Zero by 2060

As with the accelerated 2045 case, delaying the net-zero target year to 2060 does not fundamentally change the technological approach to, or infrastructure requirements of, decarbonization. Delaying the target means that the pace of infrastructure change is more gradual since it is extended over an additional ten years. In 2050, there are still net emissions of 1.5 Gt remaining. The main result of this delay from a climate perspective is 27 Gt CO_2e cumulative emissions by 2050, plus an additional 7.5 Gt CO_2e by 2060, compared to the **Central** scenario.

VII CONCLUSIONS

This section describes a series of discussion topics that have arisen during the course of this year's ADP analytical process. Many of these, like the exercise as a whole, are meant to raise relevant questions as much as to provide conclusive answers. Some of these will be further pursued in a series of upcoming EER whitepapers that will be issued after the release of the ADP.

Key Findings

(1) We have found no pathway that can avoid the need to build new clean energy infrastructure at unprecedented rates in order to reach net-zero by mid-century. Even in the drop-in scenario that preserves as much of the existing energy system as a feasible level of offsets allow, and in the low-demand scenario that limits new infrastructure build by limiting consumption to the edge of plausibility, the amounts of new infrastructure required are still on a massive scale. Put another way, our scenarios show that the U.S. cannot offset or conserve its way to net-zero. Decarbonization is an industrial-scale infrastructure problem, and the U.S. will have to, over the next three decades, build a new low-carbon infrastructure to meet the challenge.

(2) Consumer participation in decarbonization will have a large effect on outcomes. Consumer purchasing decisions (for example, purchasing technologies such as EVs and heat pumps over conventional alternatives) and consumer operational behaviors (for example, allowing their loads to be operated flexibly for the benefit of the system) are critical for cost containment in decarbonization, for example by limiting the need for electricity distribution system upgrades. The pathways that assume consumers do not rapidly adopt clean technologies, such as in the **Slow Consumer Uptake** and **Drop-In** scenarios, all result in higher energy costs.

(3) There is strong agreement in the modeling of all scenarios regarding the path to 2030, following which they diverge substantially by mid-century based on their different assumptions and constraints. This is because the economics of early decarbonization are known, leading to two clear priorities: rapid electrification in tandem with rapid deployment of renewable electricity. The recently passed Inflation Reduction Act (IRA) emphasizes these priorities in the near-term while also supporting to a limited extent the development of technologies that will be needed in subsequent decades. This legislation has the potential to help put the U.S. on a net-zero path while maintaining flexibility with regard to long-term policies and technology choices. However, achieving this potential will require (1) successful implementation of the IRA, largely by state and local governments, utilities, and manufacturers, and (2) continued policy development to address near-term gaps in the IRA as well as longer-term needs.

(4) Understanding land-based natural resource availability and constraints is critical to making good decisions about which decarbonization technologies to adopt. We still cannot say categorically if a technology (for example, advanced nuclear or DAC or electric fuels) is off the table or instead might be needed in bulk until we have a clearer idea regarding the ability to use biomass, site renewables and transmission, sequester CO_2, and increase the land CO_2 sink. There is no silver bullet technology that avoids being affected by conditions in these areas. The picture is further complicated by the localized and heterogeneous nature of many land use decisions. What some have called the "land-energy nexus" will only grow in importance as decarbonization proceeds.

(5) In the most restrictive sensitivity considered, high-voltage transmission miles increased by 60% from today's level, and in most scenarios was 2-4 times today's level. The rate of new transmission build implied by this result contrasts sharply with the very low rate of current transmission build in the U.S. Yet, if sufficient transmission is not built it will be very difficult and/or expensive to reach net-zero. Our results suggest that enabling higher transmission builds has a very high economic value. On average, the societal benefit in 2050 for transmission is about $700/MW-mile. For comparison, the cost of new high voltage long-distance transmission is about $1,500/MW-mile. This suggests that if spending public dollars can help unlock new build of transmission, such policies can be fairly generous and still have net societal benefits.

(6) Once an economy-wide net-zero target is adopted, changing the target year or requiring deeper emission reductions has little effect on the end state of energy system, though it may have an important impact on cumulative emissions. This is illustrated clearly by the net-zero in 2045, net-zero in 2060, and net-negative scenarios. These can form a useful thought experiment and help in visualizing transition processes and challenges, but do not induce the adoption of fundamentally different technologies or infrastructure. This is not the case with less ambitious targets, as in the **Net-Zero CO_2-only** scenario, which does not employ the full suite of decarbonization measures across all sectors that an economy-wide net-zero target requires.

(7) In every net-zero scenario we modeled, the societal savings in health care costs resulting from reduced air pollution are comparable to the net cost of decarbonizing the economy. In the **Central** scenario, health care savings range from 1-2 times the net cost—in other words, decarbonization pays for itself. Our results strongly support the argument that improved air quality alone makes decarbonization a compelling economic proposition.

Competing Solutions

The broad set of scenarios and sensitivities modeled in this study lend themselves to some general observations on technology and resource mitigation options that compete, sometimes in ways that are not obvious. The section below highlights some of these competitions and discusses circumstances that would tend to favor one option over another. Awareness of these competitions may help to inform policy, investment decisions, and R&D priorities.

- Electricity transmission vs. fuel pipelines. In a net-zero economy, a large amount of energy is moved from the center of the U.S. toward the east and west coasts in the forms of electricity (largely from wind) and fuels (biomass and e-fuels). In some cases, there is a choice of delivery mechanism between electric transmission lines and fuel pipelines. When the form of final energy desired is electricity, then transmission lines are selected, with the amount of new capacity depending on the extent of demand side electrification. With fuels, it is more complicated, because pipelines have a significantly higher throughput rates and significantly lower cost per mile than electric transmission. In the case of hydrogen produced from high-quality wind and solar, there is an economic choice between transmitting the electricity over a long distance then using it to produce hydrogen locally, versus producing the hydrogen close to the renewable source and shipping it by pipeline. The outcome of this competition depends on geography and factors that affect relative cost, such as the amount of energy needing to be moved.
- Direct air capture vs. biomass. In our modeling, for example in the DAC breakthrough and limited biomass cases, DAC capacity and biomass consumption move in opposite directions. This is because DAC and biomass, both of which remove CO_2 from the atmosphere, compete economically to supply zero-carbon CO_2, either for sequestration to create a source of negative emissions, or for utilization in making carbon-neutral hydrocarbon fuels. Biomass competitiveness hinges on feedstock availability and whether the U.S. can develop a biomass economy that provides a dependable biofuel supply at scale. DAC competitiveness depends on technology progress in energy intensity and capital cost, and on where renewables are sited. The availability of low cost nuclear heat and declining energy costs (both renewable and nuclear) favor DAC over biomass. DAC also provides potentially valuable insurance against mitigation plans that fall short (less electrification, limited available land, limited biomass). Both DAC and biomass face social acceptance challenges.

- Electrification vs. fuels. There are applications, such as light duty vehicles, for which electrification using decarbonized electricity is clearly economically preferable to conventional technologies using decarbonized fuel. Land use concerns also argue for electrification, which reduces the amount of land needed for e-fuel and biofuel production. There are also applications, such as aviation and chemical feedstocks, for which electrification is technically challenging and fuels are the only practical choice for the foreseeable future. Finally, there are applications, for example in the production of industrial steam, that could use either electricity or fuels. Fuel competitiveness benefits from lower resource cost, breakthroughs in production technology or DAC, and institutional failings such as poor planning of electricity distribution system upgrades or poorly implemented gas decommissioning.
- Nuclear power vs. offshore wind. As seen in the nuclear breakthrough scenario, with significant cost reductions and wide social acceptance, nuclear power would grow rapidly in a net-zero economy. Nuclear would still not be competitive with high-quality renewables such as desert solar and Midwest wind for providing the dominant share of U.S. power generation, but it would be competitive with more economically marginal renewables such as rooftop solar PV and offshore wind. Nuclear competitiveness is increased when transmission is constrained and more local generation capacity is built. Extensive offshore wind development occurs primarily in constrained transmission and limited land scenarios, in the places where nuclear development is not allowed—a phenomenon that can already be witnessed today at the state level.
- Batteries vs. flexible load. Battery storage competes with flexible customer load such as EV charging for addressing electricity supply-demand imbalance, especially on distribution systems. Flexible load is more competitive if customer participation comes at low cost, can be effectively aggregated, and includes control technologies that minimize customer impacts. Put differently, the challenge for flexible load is to be seen by utilities as equivalent to a battery at a substation. Batteries are more competitive with lower costs and with applications that require a longer-duration time shifting of energy, since many flexible loads are of limited duration.
- Utility-scale PV vs. distributed PV. Utility-scale PV is generally located where there is a higher quality resource and transmission is readily available. It is more competitive when there is available land, low cost transmission, and the potential for co-location with large scale electrolysis or DAC facilities. Distributed PV competitiveness improves if there are land use or transmission constraints that limit the construction of large-scale solar farms. If the capital cost of solar panels declines below a certain level such that transmission becomes a large share of total cost, this would also favor distributed PV.
- Sequestration vs. utilization. Whether to sequester CO_2 or to utilize it to make fuels comes down to the cost of producing decarbonized hydrogen. Low renewable cost and available land favor electrolysis for hydrogen production and make CO_2 utilization more competitive, while the opposite conditions favor sequestration.

Hydrogen plays a key role in all scenarios even though it is used in relatively limited volumes compared to the fuels of today, due to its cost. Some end uses are more high value and some are more marginally competitive against alternatives, but hydrogen's role as an intermediate energy carrier whose production helps to balance high-renewables electricity systems is critical.

- Industrial steam decarbonization. Providing decarbonized steam to industrial processes is a three-way competition between heat pumps, thermal energy storage, and dual-fuel boilers. Heat pump competitiveness hinges on achieving low capital costs. Dual-fuel (electric and combustion fuel) boilers are more competitive when there are irregular renewable curtailment patterns in the electricity system, for example with high penetrations of wind generation, making storage operate at low capacity factors. Thermal storage competitiveness revolves around low capital cost, high reliability, co-location with PV. It also hinges on changing current utility rate designs to reflect the utility's ability to avoid distribution upgrades through customer use of thermal storage. More broadly, the economic decarbonization of industrial heat is reliant on sector coupling and taking advantage of cheaper opportunities for energy storage.

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IX SUPPLEMENTAL RESULTS

FIGURE 37.

Baseline 2050 Energy Sankey Diagram

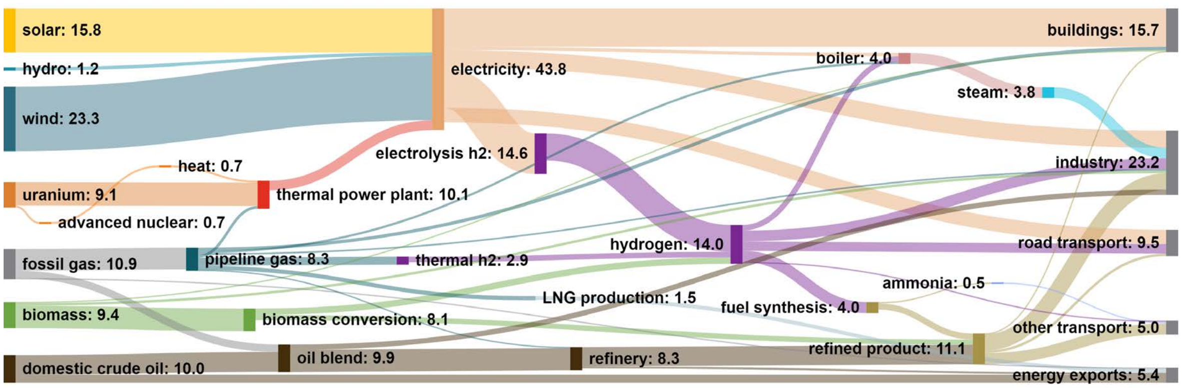


FIGURE 38.

Low Demand 2050 Energy Sankey Diagram

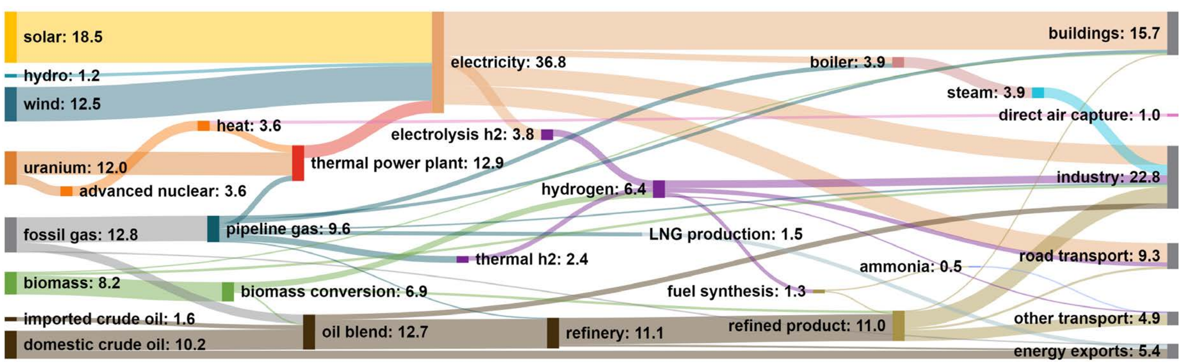


FIGURE 39.

High Hydrogen 2050 Energy Sankey Diagram

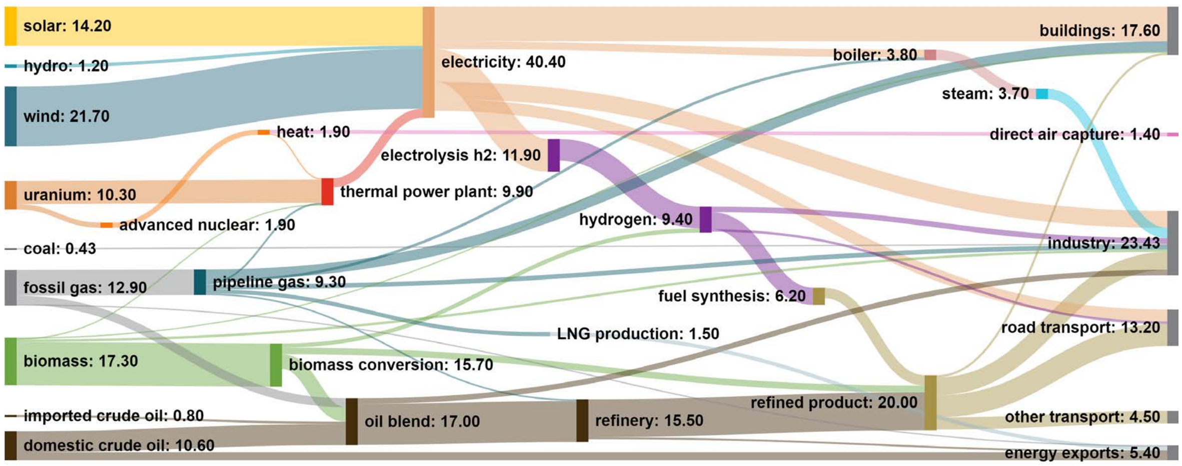


FIGURE 40.

Low Land 2050 Energy Sankey Diagram

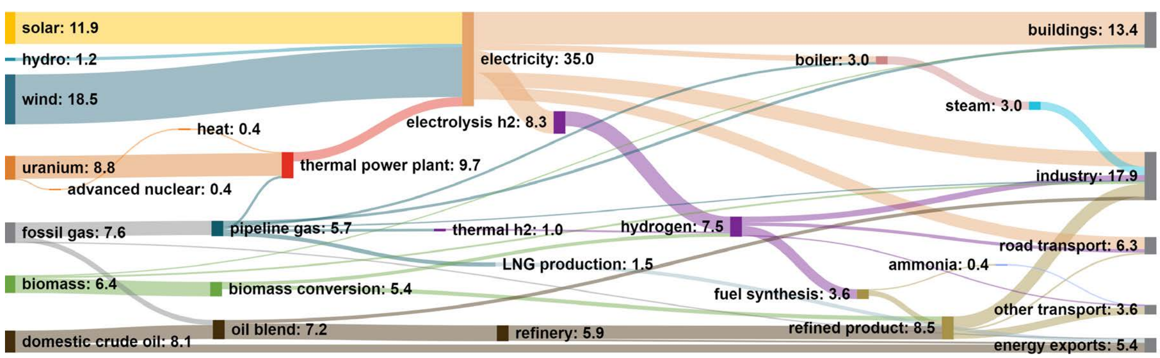


FIGURE 41.

Slow Consumer Uptake 2050 Energy Sankey Diagram

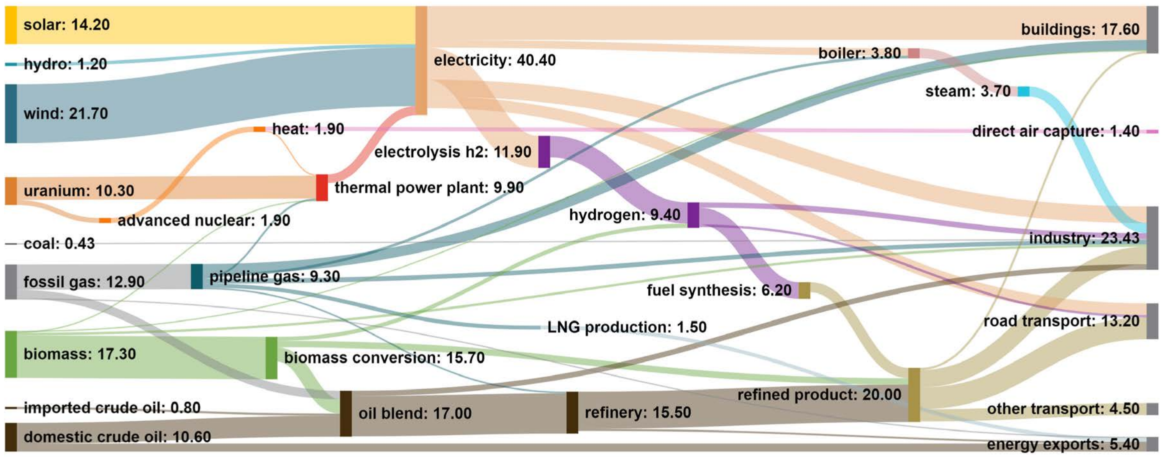


FIGURE 42.

GHG Emissions by Scenario

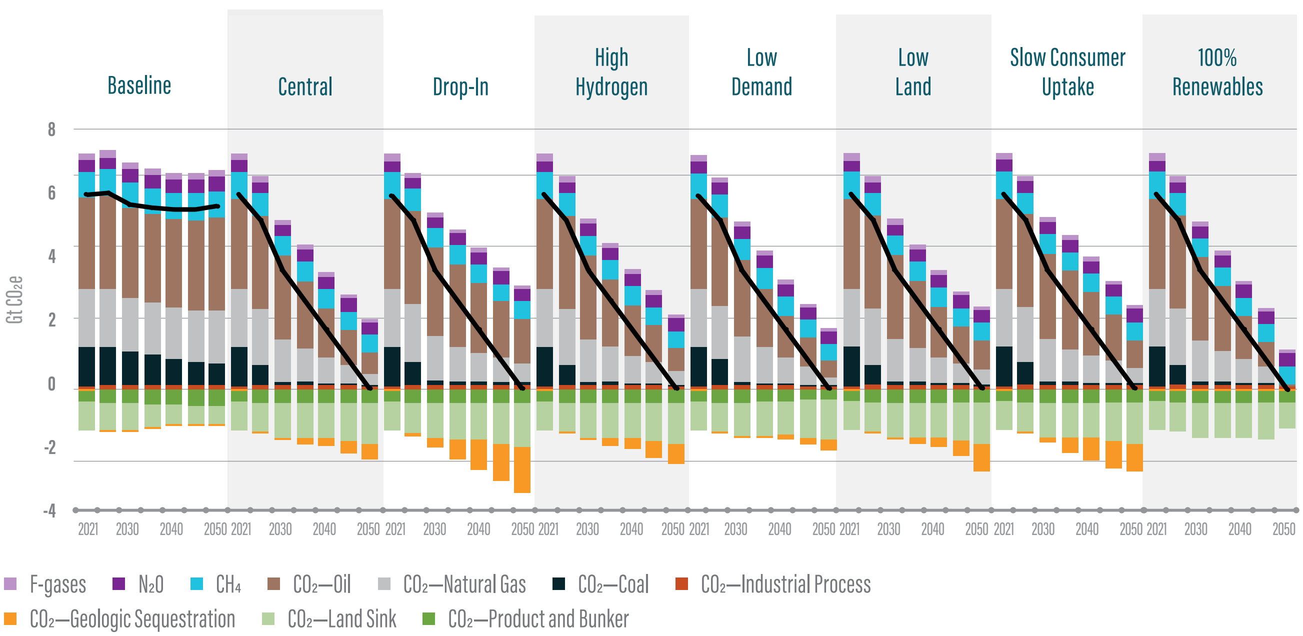


FIGURE 43.

Hydrocarbon Production Capacity

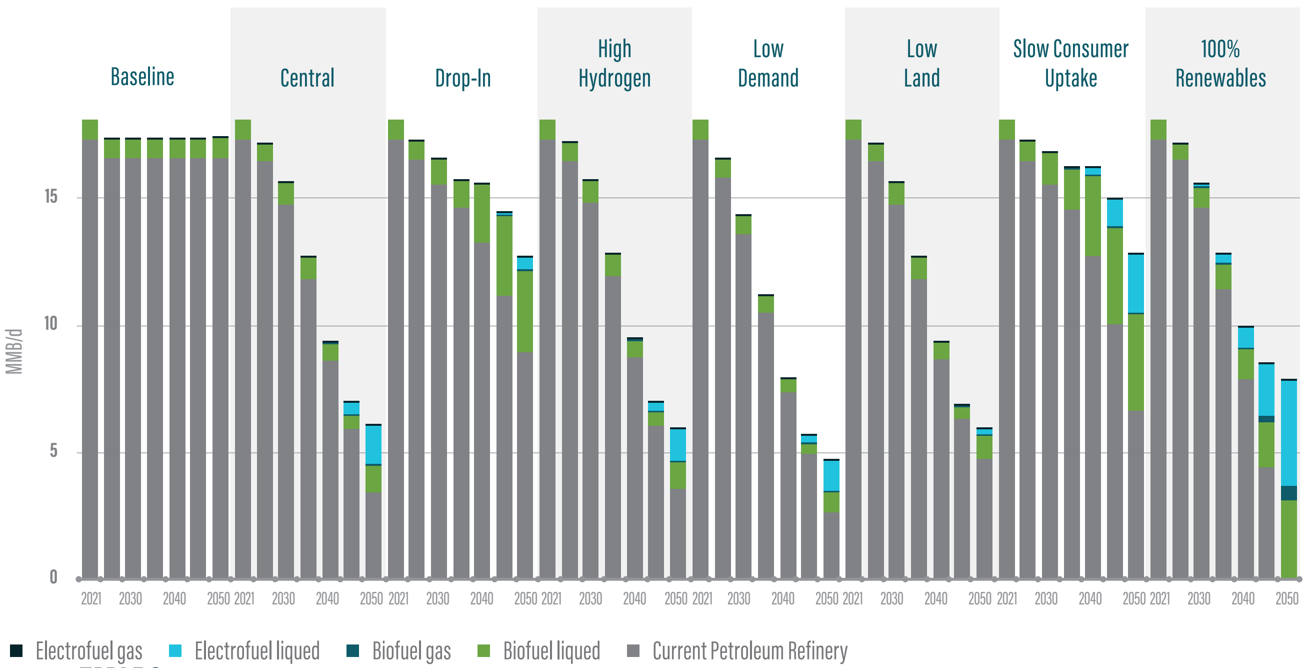


TABLE 6.

Summary table for low fuel price and low renewables cost scenarios

Indicator	Units	2021	2050 Baseline	Central	Central - Low Fossil Prices	Central - Low Renewables Costs	Baseline - Low Fossil Prices	Baseline - Low Renewables Costs
EMISSIONS								
Gross E&I CO_2	Mt	5,327	4,784	1,029	1,195	756	4,869	4,461
Non-CO_2	Mt	1,244	1,321	933	939	925	1,332	1,309
Uncombusted & bunkered CO_2	Mt	-340	-488	-376	-376	-376	-488	-488
Land-sink CO_2	Mt	-795	-490	-1,141	-1,141	-1,141	-490	-490
Geologic sequestration	Mt	0	-4	-449	-622	-169	-6	0
Net Emissions CO_2ee	Mt	5,436	5,123	-4	-5	-5	5,217	4,792
Cumulative Net E&I CO_2	Gt	NA	135.9	74.5	74.3	74.6	137.6	130.6
CCUS								
E&I CO_2 captured	Mt	0	9	620	725	531	9	12
E&I CO_2 utilized	Mt	0	5	171	103	362	3	12
E&I CO_2 sequestered	Mt	0	4	449	622	169	6	0

Indicator	Units	2021	2050 Baseline	Central	Central - Low Fossil Prices	Central - Low Renewables Costs	Baseline - Low Fossil Prices	Baseline - Low Renewables Costs
PRIMARY ENERGY SUPPLY								
Petroleum	EJ	35.5	36.5	8.8	10.3	5.7	36.6	36.4
Natural Gas	EJ	32.3	29.6	5.4	6.6	4.3	32.3	26.7
Coal	EJ	12.4	6.6	0.1	0.1	0.1	6.0	4.7
Biomass	EJ	4.3	4.5	10.3	10.3	8.8	4.4	4.5
Nuclear	EJ	8.8	7.9	9.3	9.1	8.7	7.4	6.2
Solar	EJ	0.6	5.5	15.9	14.4	19.8	5.1	6.3
Wind	EJ	1.4	6.5	22.7	20.4	28.3	5.8	9.1
Hydro	EJ	1.0	1.0	1.1	1.1	1.0	0.9	0.9
Geothermal	EJ	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	EJ	96.3	97.9	73.6	72.3	76.7	98.4	94.8
FINAL ENERGY DEMAND								
Residential	EJ	12.7	14.1	9.3	9.3	9.3	14.1	14.1
Commercial	EJ	9.6	10.9	8.0	8.0	8.0	10.9	10.9
Transportation	EJ	25.8	26.1	14.8	14.8	14.8	26.1	26.1
Industry	EJ	19.6	25.6	22.1	22.1	22.1	25.6	25.6
Total	EJ	67.6	76.6	54.2	54.2	54.2	76.6	76.6
ELECTRICITY SHARE OF FINAL ENERGY								
Buildings - Residential	%	46%	55%	87%	87%	87%	55%	55%
Buildings - Commercial	%	50%	54%	90%	90%	90%	53%	53%
On-road transport	%	0%	3%	74%	74%	74%	3%	3%
Transport other	%	0%	1%	8%	8%	8%	1%	1%
Industry	%	18%	31%	33%	40%	39%	18%	18%
Total	%	21%	29%	55%	58%	57%	25%	24%
HYDROGEN SHARE OF FINAL ENERGY								
On-road transport	%	0%	0%	17%	17%	17%	0%	0%
Transport other	%	0%	0%	16%	16%	16%	0%	0%
Industry	%	5%	4%	13%	13%	13%	4%	4%
Total	%	1%	2%	10%	10%	10%	1%	1%
ELECTRIC GENERATION								
Total generation	TWh	4,041	5,530	12,112	11,085	14,616	5,435	5,905
Thermal capacity factor	%	37.3%	24.6%	4.0%	5.4%	3.2%	28.6%	17.7%
Wind	%	9.4%	32.4%	52.2%	51.1%	53.9%	29.6%	43.0%
Solar	%	4.2%	27.4%	36.5%	36.0%	37.6%	25.8%	29.7%
Hydro	%	7.4%	5.7%	2.8%	3.1%	2.2%	5.4%	4.7%

Indicator	Units	2021	2050 Baseline	Central	Central - Low Fossil Prices	Central - Low Renewables Costs	Baseline - Low Fossil Prices	Baseline - Low Renewables Costs
Biomas	%	0.7%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Biomas w/CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	%	20.0%	13.0%	7.0%	7.4%	5.4%	12.5%	9.6%
Coal	%	26.8%	9.8%	0.0%	0.0%	0.0%	9.0%	6.1%
Coal w/CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Gas	%	31.4%	11.3%	1.4%	1.7%	0.9%	17.6%	6.7%
Gas w/ CC	%	0.0%	0.0%	0.1%	0.7%	0.0%	0.0%	0.0%
HYDROCARBON FUELS								
Total production	EJ	76.3	69.1	17.2	18.3	16.1	71.0	64.4
Fossil share production	%	98%	98%	69%	80%	48%	98%	97%
Biomass share production	%	2%	2%	17%	12%	19%	2%	2%
Electric fuel share production	%	0%	0%	15%	8%	33%	0%	0%
Consumed as solid	%	16%	10%	2%	2%	2%	9%	8%
Consumed as liquid	%	44%	51%	64%	60%	68%	50%	55%
Consumed as gas	%	39%	39%	34%	38%	30%	41%	37%
COST								
Gross Cost 2050	$B	1,085	1,296	1,532	1,507	1,485	1,196	1,281
Decarb net cost 2050	$B	NA	NA	236	312	204	NA	NA
Decarb total net cost NPV	$B	NA	NA	1,866	2,449	1,558	NA	NA
Net AQ health benefits 2050	$B	NA	NA	400	399	401	NA	NA
INDICATORS								
US population	Million	335	406	406	406	406	406	406
Utility wind & solar land use	MHa	2.8	10.3	31.7	28.7	38.5	9.2	13.6
Interregional transmission capacity	GW-kilomiles	52	67	198	191	189	64	74
Per capita energy use rate	GJ/person	202	189	134	134	134	189	189
Per capita emissions	t CO_2/person	16.2	12.6	0.0	0.0	0.0	12.8	11.8
US GDP	$T	21.3	40.1	40.1	40.1	40.1	40.1	40.1
Net cost as share of GDP	%	NA	NA	0.6%	0.8%	0.5%	NA	NA

Indicator	Units	2021	2050 Baseline	Central	Central - Low Fossil Prices	Central - Low Renewables Costs	Baseline - Low Fossil Prices	Baseline - Low Renewables Costs
Economic energy intensity	MJ/$	4.5	2.4	1.8	1.8	1.9	2.5	2.4
Economic emission intensity	kg CO2/$	0.26	0.13	0.00	0.00	0.00	0.13	0.12
Electric emission intensity	g CO_2/kWh	396	138	4	5	3	153	84

TABLE 7. Summary table for technology and emissions target sensitivities

Indicator	Units	Limited Biomass	No Sector Coupling	Nuclear Breakthrough	Transmission Friction	DAC Breakthrough	High Flexible Load	Net-zero CO_2 Only	Net Negative	2045 Net-zero	2060 Net-zero
EMISSIONS											
Gross E&I CO_2	Mt	1,086	1,219	1,005	1,301	1,204	1,029	1,672	776	1,052	2,049
Non-CO_2	Mt	935	941	931	943	939	933	0	925	935	983
Uncombusted & bunkered CO_2	Mt	-376	-376	-376	-376	-376	-376	-376	-376	-376	-376
Land-sink CO_2	Mt	-1,141	-1,141	-1,141	-1,141	-1,141	-1,141	-1,122	-1,141	-1,128	-1,109
Geologic sequestration	Mt	-509	-648	-425	-731	-631	-450	-180	-690	-489	-56
Net Emissions CO2ee	Mt	-5	-5	-6	-4	-5	-5	-6	-506	-6	1,491
Cumulative Net E&I CO_2	Gt	74.5	74.4	74.5	74.4	74.4	74.5	87.2	69.4	66.6	101.8
CCUS											
E&I CO_2 captured	Mt	693	681	592	771	795	614	226	907	673	76
E&I CO_2 utilized	Mt	184	33	167	40	164	164	46	217	184	20
E&I CO_2 sequestered	Mt	509	648	425	731	631	450	180	690	489	56
PRIMARY ENERGY SUPPLY											
Petroleum	EJ	9.3	10.0	9.1	11.2	10.3	8.8	12.2	6.0	8.0	16.0
Natural Gas	EJ	5.8	7.4	4.5	7.5	6.8	5.4	13.5	4.3	6.9	15.1
Coal	EJ	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.4
Biomass	EJ	7.2	11.5	9.3	11.6	6.1	10.3	2.2	14.6	9.9	2.7
Nuclear	EJ	10.2	9.3	29.4	12.9	10.7	9.2	8.8	9.9	9.2	8.8
Solar	EJ	16.8	14.4	12.0	12.5	16.1	15.8	13.2	16.4	15.8	11.2

Indicator	Units	Limited Biomass	No Sector Coupling	Nuclear Breakthrough	Transmission Friction	DAC Breakthrough	High Flexible Load	Net-zero CO_2 Only	Net Negative	2045 Net-zero	2060 Net-zero
Wind	EJ	23.6	18.5	20.3	17.2	23.2	22.6	18.6	24.0	22.6	16.1
Hydro	EJ	1.1	1.1	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.0
Geothermal	EJ	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	EJ	74.1	72.3	85.6	74.1	74.3	73.3	69.6	76.5	73.6	71.3
FINAL ENERGY DEMAND											
Residential	EJ	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.2	9.8
Commercial	EJ	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.3
Transportation	EJ	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.8	14.5	16.1
Industry	EJ	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.1	22.0
Total	EJ	54.2	54.2	54.2	54.2	54.2	54.2	54.2	54.2	53.9	56.2
ELECTRICITY SHARE OF FINAL ENERGY											
Buildings - Residential	%	87%	87%	87%	87%	87%	87%	87%	87%	88%	80%
Buildings - Commercial	%	90%	90%	90%	90%	90%	90%	90%	90%	91%	82%
On-road transport	%	74%	74%	74%	74%	74%	74%	74%	74%	78%	55%
Transport other	%	8%	8%	8%	8%	8%	8%	8%	8%	8%	6%
Industry	%	33%	40%	35%	40%	39%	38%	40%	41%	39%	37%
Total	%	55%	58%	56%	58%	58%	57%	58%	58%	59%	51%
HYDROGEN SHARE OF FINAL ENERGY											
On-road transport	%	17%	17%	17%	17%	17%	17%	17%	17%	19%	12%
Transport other	%	16%	16%	16%	16%	16%	16%	16%	16%	16%	12%
Industry	%	20%	13%	13%	13%	13%	13%	13%	13%	13%	11%
Total	%	13%	10%	10%	10%	10%	10%	10%	10%	10%	8%
ELECTRIC GENERATION											
Total generation	TWh	12,576	10,654	12,058	10,154	12,300	12,035	10,435	12,595	12,075	9,262
Thermal capacity factor	%	3.5%	7.6%	2.1%	7.1%	4.7%	3.9%	8.9%	3.4%	5.1%	11.3%
Wind	%	52.1%	48.2%	46.8%	47.1%	52.3%	52.2%	49.5%	53.0%	51.9%	48.4%
Solar	%	37.1%	37.6%	27.5%	34.3%	36.3%	36.5%	35.1%	36.3%	36.3%	33.5%
Hydro	%	2.7%	3.1%	2.6%	3.4%	2.8%	2.8%	3.2%	2.7%	2.8%	3.5%
Biomas	%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Biomas w/CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	%	6.8%	7.9%	22.4%	11.5%	6.8%	6.9%	7.7%	6.8%	7.0%	8.6%
Coal	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Coal w/CC	%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Indicator	Units	Limited Biomass	No Sector Coupling	Nuclear Breakthrough	Transmission Friction	DAC Breakthrough	High Flexible Load	Net-zero CO_2 Only	Net Negative	2045 Net-zero	2060 Net-zero
Gas	%	1.2%	2.5%	0.5%	3.2%	1.7%	1.4%	4.4%	1.1%	2.0%	5.8%
Gas w/ CC	%	0.1%	0.7%	0.0%	0.3%	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%
HYDROCARBON FUELS											
Total production	EJ	17.5	19.2	16.3	19.1	18.4	17.2	23.8	16.2	17.1	29.3
Fossil share production	%	76%	81%	69%	86%	79%	69%	95%	59%	76%	96%
Biomass share production	%	8%	16%	16%	11%	8%	17%	2%	21%	8%	3%
Electric fuel share production	%	16%	3%	15%	3%	13%	14%	3%	20%	16%	1%
Consumed as solid	%	2%	2%	2%	2%	2%	2%	1%	2%	2%	2%
Consumed as liquid	%	63%	58%	67%	58%	60%	64%	46%	68%	61%	50%
Consumed as gas	%	35%	41%	31%	41%	38%	34%	52%	30%	37%	48%
COST											
Gross Cost 2050	$B	1,543	1,542	1,514	1,544	1,529	1,517	1,423	1,598	1,538	1,379
Decarb net cost 2050	$B	247	245	218	247	233	220	126	302	241	83
Decarb total net cost NPV	$B	1,888	1,940	1,869	1,909	1,857	1,682	994	2,234	2,424	581
Net AQ health benefits 2050	$B	400	399	399	399	399	400	396	400	400	367
INDICATORS											
US population	Million	406	406	406	406	406	406	406	406	406	406
Utility wind & solar land use	MHa	32.9	29.4	29.3	22.6	32.3	31.5	26.6	33.2	31.4	23.4
Interregional transmission capacity	GW-kilomiles	199	209	140	88	190	195	162	207	195	150
Per capita energy use rate	GJ/person	134	134	134	134	134	134	134	134	133	138
Per capita emissions	t CO_2/person	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-1.2	0.0	3.7
US GDP	$T	40.1	40.1	40.1	40.1	40.1	40.1	40.1	40.1	40.1	40.1
Net cost as share of GDP	%	0.6%	0.6%	0.5%	0.6%	0.6%	0.5%	0.3%	0.8%	0.6%	0.2%
Economic energy intensity	MJ/$	1.8	1.8	2.1	1.8	1.9	1.8	1.7	1.9	1.8	1.8
Economic emission intensity	kg CO_2/$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	0.00	0.04

Indicator	Units	Limited Biomass	No Sector Coupling	Nuclear Breakthrough	Transmission Friction	DAC Breakthrough	High Flexible Load	Net-zero CO_2 Only	Net Negative	2045 Net-zero	2060 Net-zero
Electric emission intensity	g CO_2/ kWh	4	8	2	11	5	4	16	3	7	22

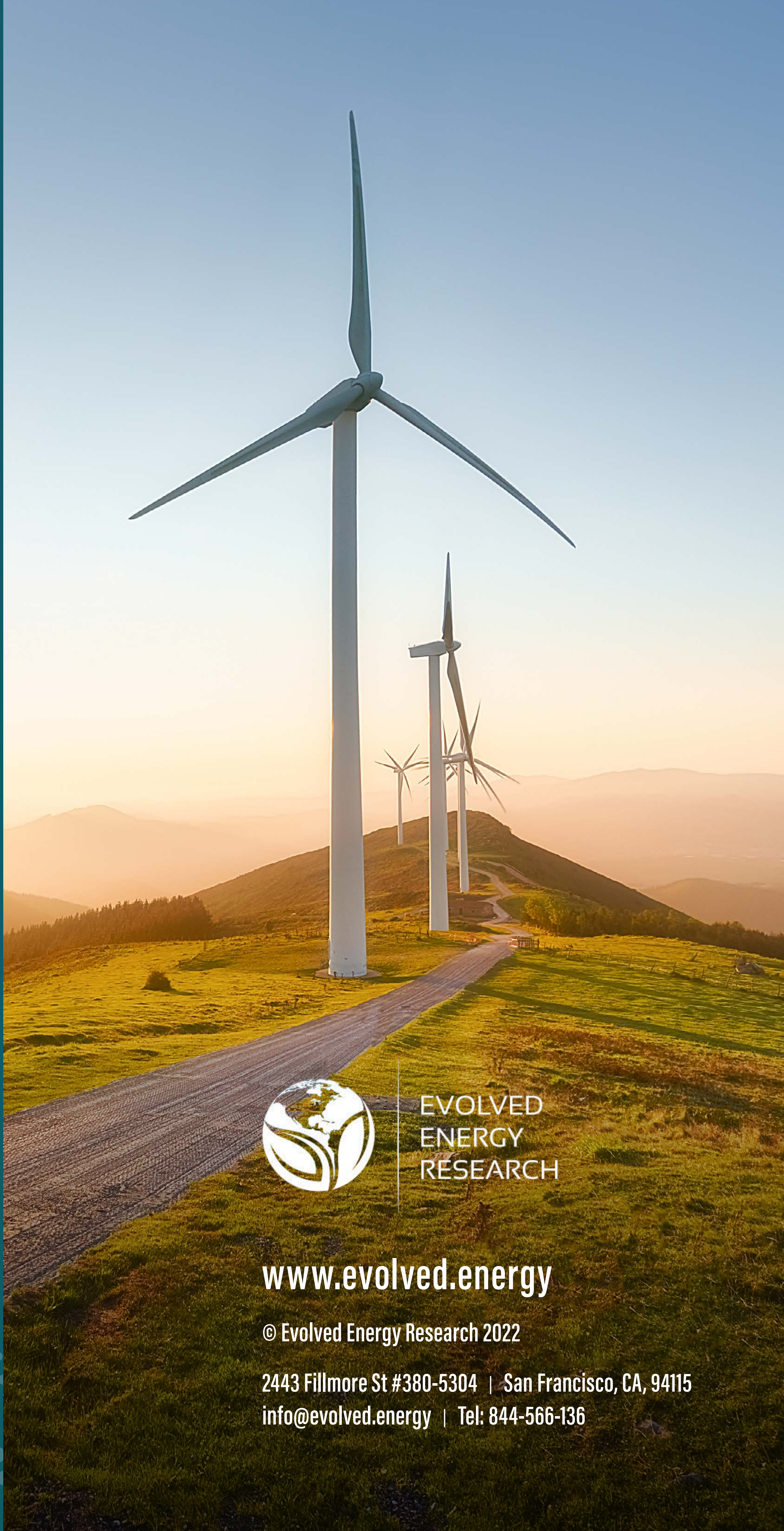
TABLE 8.

Summary table for technology and emissions target sensitivities

Scenario	Scenario Narrative
Baseline	Total U.S. GHG emissions decline slightly (6% by 2050), with a 14% decline in energy and industrial CO_2 (net of uncombusted and bunkered fuels plus geologic sequestration) partly offset by a 6% increase in non-CO_2 GHGs and a 38% decrease in the land CO_2 sink. U.S. per capita emissions decline by 22% while cumulative CO_2 emissions exceed 130 Gt. Fossil fuel still dominates primary energy supply but its share declines slightly to 74%, with coal reduced by half and displaced by wind and solar, which comprise 60% of electricity generation. Fuel production decreases slightly but remains 98% fossil in origin. Transportation electrification is minimal (4%), and building electrification is only slightly higher than today's. Hydrogen production and CO_2 capture are minimal. Land use for utility-scale wind and solar is 10 million hectares. The gross cost of the energy system in 2050 is $1,296B, or 3.2% of forecast GDP.
Central	Total U.S. GHG emissions decline to net-zero in 2050, based on a 96% decrease in energy and industrial CO_2 (net of uncombusted and bunkered fuels plus geologic sequestration) a 25% decrease in non-CO_2 GHGs, and a 44% increase in the land CO_2 sink. U.S. per capita emissions reach zero while cumulative CO_2 emissions from 2021 to 2050 are a little over half of those in the **Baseline** scenario. Efficiency improvements reduce primary and final energy demand by more than 20% despite economic and population growth. Primary energy supply is two-thirds wind (31%), solar (22%), and biomass (14%), with the fossil fuel share declining to 19%. Wind and solar comprise 89% of electricity generation, which grows to 3.0 times the 2021 level. Nuclear generation maintains about today's level of generation but its share decreases by two-thirds. Electricity is the final energy supply for 74% of on-road transport, with hydrogen supplying an additional 17%. Electricity supplies 88% of final energy in buildings. With high electrification, fuel production decreases 77% from 2021, with the remaining fuel shares being 69% fossil, 17% biomass, and 15% electric fuels. 620 Mt of CO_2 are captured, of which 449 Mt is sequestered geologically and the remainder utilized. Land use for utility-scale wind and solar is 32 million hectares. The gross cost of the energy system in 2050 is $1,532B, or 3.8% of forecast GDP. The net cost of reaching net-zero compared to the baseline high-emissions case is $236B, or 0.6% of forecast GDP.
Drop-in	Total U.S. GHG emissions decline to net-zero in 2050, based on a 94% decrease in energy and industrial CO_2 and a 25% decrease in non-CO_2 GHGs. The residual CO_2 emissions are offset by a 56% increase in the land CO_2 sink plus geological sequestration. Primary energy supply is 34% fossil fuel, 29% wind and solar, 22% biomass, and 14% nuclear. Electricity generation grows to 2.1 times the 2021 level, with wind and solar comprising 79% and nuclear power comprising 10%. Electrification is limited, with electricity as the final energy supply for only 31% of on-road transport, and hydrogen is only 2% of all final energy. Electricity supplies 73% of final energy in buildings. Fuel production decreases 56% from 2021, with the remaining fuel shares being 87% fossil and 11% biomass. 1320 Mt of CO_2 is captured, of which 1271 Mt is sequestered geologically. Land use for utility-scale wind and solar is 20 million hectares. The gross cost of the energy system in 2050 is $1,798B, or 4.4% of forecast GDP. The net cost is $502B, or 1.3% of forecast GDP.

Scenario	Scenario Narrative
Slow Consumer Uptake	Total U.S. GHG emissions decline to net-zero in 2050, based on a 96% decrease in energy and industrial CO_2, a 24% decrease in non-CO_2 GHGs, and a 44% increase in the land CO_2 sink. Because electrification rates are lower, fuel demand and primary energy demand are higher than other scenarios. Primary energy supply is 23% fossil fuel, 42% wind and solar, 21% biomass, and 12% nuclear. Electricity generation grows to 2.8 times the 2021 level, with wind and solar comprising 88% and nuclear power comprising 7%. The electricity share of final energy is similar to the drop-in case at 44%. Electricity supplies the final energy supply for only 33% of on-road transport. Hydrogen comprises 5% of all final energy, and is used especially in heavy transport and industry. Fuel production decreases 61% from 2021, with the remaining fuel shares being 75% fossil, 12% biomass, and 13% electric fuels. 1058 Mt of CO_2 is captured, of which 802 Mt is sequestered geologically. Land use for utility-scale wind and solar is 31 million hectares. The gross cost of the energy system in 2050 is $1,612B, or 4.0% of forecast GDP. The net cost is $316B, or 0.8% of forecast GDP.
Low Land	Total U.S. GHG emissions decline to net-zero in 2050, based on a 96% decrease in energy and industrial CO_2, a 24% decrease in non-CO_2 GHGs, and a 44% increase in the land CO_2 sink. Primary energy supply is 27% fossil fuel, 42% wind and solar, 13% biomass, and 16% nuclear. Electricity generation grows to 2.5 times the 2021 level, with wind and solar comprising 84% and nuclear power comprising 10%. Since the demand side is the same as the Central scenario, final energy demand and the electrification and hydrogen shares of final energy are the same. Fuel production decreases 74% from 2021, with the remaining fuel shares being 88% fossil, 9% biomass, and only 2% electric fuels. 819 Mt of CO_2 is captured, of which 790 Mt is sequestered geologically. Land use for utility-scale wind and solar was constrained to 16 million hectares. The gross cost of the energy system in 2050 is $1,558B, or 3.9% of forecast GDP. The net cost is $262B, or 0.7% of forecast GDP.
High Hydrogen	Total U.S. GHG emissions decline to net-zero in 2050, based on a 96% decrease in energy and industrial CO_2, a 25% decrease in non-CO_2 GHGs, and a 44% increase in the land CO_2 sink. Primary energy supply consists of 21% fossil fuel, 51% wind and solar, 14% biomass, and 12% nuclear. Electricity generation grows to 3.0 times the 2021 level, with wind and solar comprising 89% and nuclear power comprising 7%. The electricity share of final energy demand is 53%. The hydrogen share is 15%, including 36% of on-road transport and 18% of other transportation final energy, along with 18% of industrial final energy. Fuel production decreases 76% from 2021, with the remaining fuel shares being 73% fossil, 16% biomass, and 12% electric fuels. 706 Mt of CO_2 is captured, of which 559 Mt is sequestered geologically. Land use for utility-scale wind and solar is 32 million hectares. The gross cost of the energy system in 2050 is $1,608B, or 3.0% of forecast GDP. The net cost is $312B, or 0.8% of forecast GDP.
Low Demand	Total U.S. GHG emissions decline to net-zero in 2050, based on a 96% decrease in energy and industrial CO_2, a 26% decrease in non-CO_2 GHGs, and a 44% increase in the land CO_2 sink. Primary energy supply is reduced by 39% from 2021, and consists of 18% fossil fuel, 52% wind and solar, 13% biomass, and 15% nuclear. Electricity generation grows to 2.4 times the 2021 level, with wind and solar comprising 87% and nuclear power comprising 8%. The electricity share of final energy demand is 55%, and the hydrogen share is 10%. Fuel production decreases 82% from 2021, with the remaining fuel shares being 66% fossil, 19% biomass, and 15% electric fuels. 420 Mt of CO_2 is captured, of which 285 Mt is sequestered geologically. Land use for utility-scale wind and solar is 26 million hectares. The gross cost of the energy system in 2050 is $1,200B, or 3.0% of forecast GDP. The net cost is negative, at -$96B, or -0.2% of forecast GDP.

Scenario	Scenario Narrative
100% Renewable	Total U.S. GHG emissions decline slightly below net-zero to -31 Mt CO_2e in 2050, based on a 105% decrease in energy and industrial CO_2 and a 23% decrease in non-CO_2 GHGs, partly offset by a 7% decrease in the land CO_2 sink. Primary energy supply is 100% renewable, mostly wind (40%), solar (37%), and biomass (22%), with no fossil fuel and no nuclear power. Wind and solar comprise 98% of electricity generation, which grows to 4.1 times the 2021 level, with 2.1% of hydro and 0.4% of biogas generation for balancing. Since the demand side is the same as the Central scenario, final energy demand and the electrification and hydrogen shares of final energy are the same. Fuel production decreases 81% from 2021, with the remaining fuel shares being 49% biomass and 51% electric fuels. 484 Mt of CO_2 are captured, of which all is utilized and none is geologically sequestered. Land use for utility-scale wind and solar is 41 million hectares. The gross cost of the energy system in 2050 is $1,678B, or 3.8% of forecast GDP. The net cost is $381B, or 1.0% of forecast GDP.



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