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Future Scenarios of Power System and Infrastructure in the United States

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List of Acronyms and Abbreviations

AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BA	balancing area
CAGR	compound annual growth rate
CCS	carbon capture and storage
CSP	concentrating solar power
DER	distributed energy resources
DOE	U.S. Department of Energy
EFS	Electrification Futures Study
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
GDP	gross domestic product
GW	gigawatts
HDV	heavy-duty vehicle
HOGRT	high oil and gas resource and technology
HVAC	heating, ventilation, and air conditioning
LCOE	levelized cost of energy
LDV	light-duty vehicle
LOGRT	low oil and gas resource and technology
MDV	medium-duty vehicle
NEMS	National Energy Modeling System
NG-CC	natural gas combined cycle
NG-CT	natural gas combustion turbine
NREL	National Renewable Energy Laboratory
RE	renewable energy
VRE	variable renewable energy
WACC	weighted-average cost of capital

Executive Summary

Electrification, the shift from non-electric to electric sources of energy at the point of final consumption, is an emerging trend that could have major implications for global energy systems. The Electrification Futures Study (EFS) is a multiyear collaborative study designed to assess the potential impacts that could arise if widespread electrification occurs in the United States. The EFS is particularly attentive to the ways in which electrification could affect different parts of the energy system, including demand sectors (buildings, industrial, and transportation) and energy supply systems. Due to the complex nature of these interactions, results from the EFS are presented through a series of reports focused on specific topics.

This report, the fifth in the series,[1] presents an analysis of the potential impacts of widespread electrification on the evolution of the U.S. electricity system. In particular, we examine how electrification could drive changes in generation and transmission infrastructure investments, fuel use, system costs, and air emissions. We apply a scenario analysis approach that covers a wide range of potential futures based on variations across several dimensions, the most prominent of which is electrification level. Scenarios with the lowest amount of electrification considered, which we refer to as the Reference electrification level, include modest amounts of adoption for cost-competitive electric end-use technologies only. On the upper end are our High electrification scenarios, which reflect transformational electrification in multiple demand sectors. These *demand-side scenarios* are described in more detail by Mai et al. (2018), and they should not be interpreted as either predictions or bounding scenarios for future end-use electric technology adoption. In addition to electrification, the other dimensions that are varied in our scenario analysis include electric end-use technology advancement, demand-side flexibility, natural gas resources, renewable energy and storage technology improvements, and an assortment of potential constraints on the bulk power system.

The *supply-side scenarios*, which are the focus of this report, are simulated using the National Renewable Energy Laboratory (NREL) Regional Energy Deployment System (ReEDS) model (Cohen et al. 2019). ReEDS is a capacity expansion model that identifies least-cost portfolios of the U.S. power system from the present through 2050, and several changes to the model were made to enable it to better reflect the impacts of electrification, as detailed in a companion report (Sun et al. 2020). The ReEDS scenario and impacts analysis results build upon the demand sector analysis presented in prior EFS reports (Jadun et al. 2017; Mai et al. 2018). Thus, the findings presented here reflect outcomes from a combination of power sector-specific results (when appropriate) and broader energy system-wide results (whenever possible).

The analysis is designed to address the following research questions:

- What are the impacts of electrification on the mix, magnitude, location, and timing of new bulk power system infrastructure development in the United States?
- How could widespread end-use electrification impact the generation mix and utilization of different classes of generators and transmission assets?
- What are the impacts of electrification on costs, energy consumption, and air emissions for the electric and broader energy systems?

[1] An accompanying journal article (Murphy et al. 2020) presents a subset of the results included in this report.

In this Executive Summary, we present the resulting key qualitative findings related to these questions. Additional discussion and presentation of quantitative results can be found in the body of the report, and the underlying model results can be explored through our scenario reviewer.[2] Based on trends from the full suite of scenarios simulated, the five key findings are as follows:

1. **Electrification drives the sustained deployment of renewable energy and natural gas generators in *all* regions and, in turn, increases generation from these sources; the corresponding expansion of long-distance transmission capacity is correlated with growth in renewable energy sources**.
   A. Electrification-driven reductions in end-use natural gas consumption, and the resulting downward pressure on natural gas prices increases the competitiveness of natural gas-fired electricity generation (Figure ES-1), in the absence of new policies. The extent to which natural gas-fired generation could be relied upon to meet growing electricity demand also depends on physical and market forces that introduce significant uncertainty in the future price of natural gas (Figure ES-2).
   B. The growing deployment of renewable energy technologies is expected to continue and is amplified by electrification (Figure ES-1), potentially to unprecedented levels (Figure ES-2). The ultimate pace and extent of renewable energy deployment depends strongly on future market, technology, and policy conditions, which dictate the relative competitiveness of new natural gas versus renewable energy technologies.
   C. Beyond renewable energy and natural gas deployment, energy storage is used to meet changes from electrification, including to meet greater planning reserve requirements driven by higher demand peaks (Figure ES-2).
   D. Local resources are increasingly relied upon to meet electrification-driven load growth, which mitigates the influence of electrification on the need for additional long-distance, inter-regional transmission expansion (Figure ES-1). However, the magnitude of short transmission segments to interconnect new renewable energy generators scales with electrification, and *total* transmission capacity expansion scales with renewable energy deployment levels.
   E. Due to several unique aspects of electrification—including how it changes load shapes, drives the increased deployment of flexible generation technologies, and could potentially expand demand-side flexibility—we find that it could lead to a more conducive environment for integrating variable renewable energy technologies.

[2] ReEDS model results for this study are available for viewing and download at https://cambium.nrel.gov/?project=fc00a185-f280-47d5-a610-2f892c296e51.

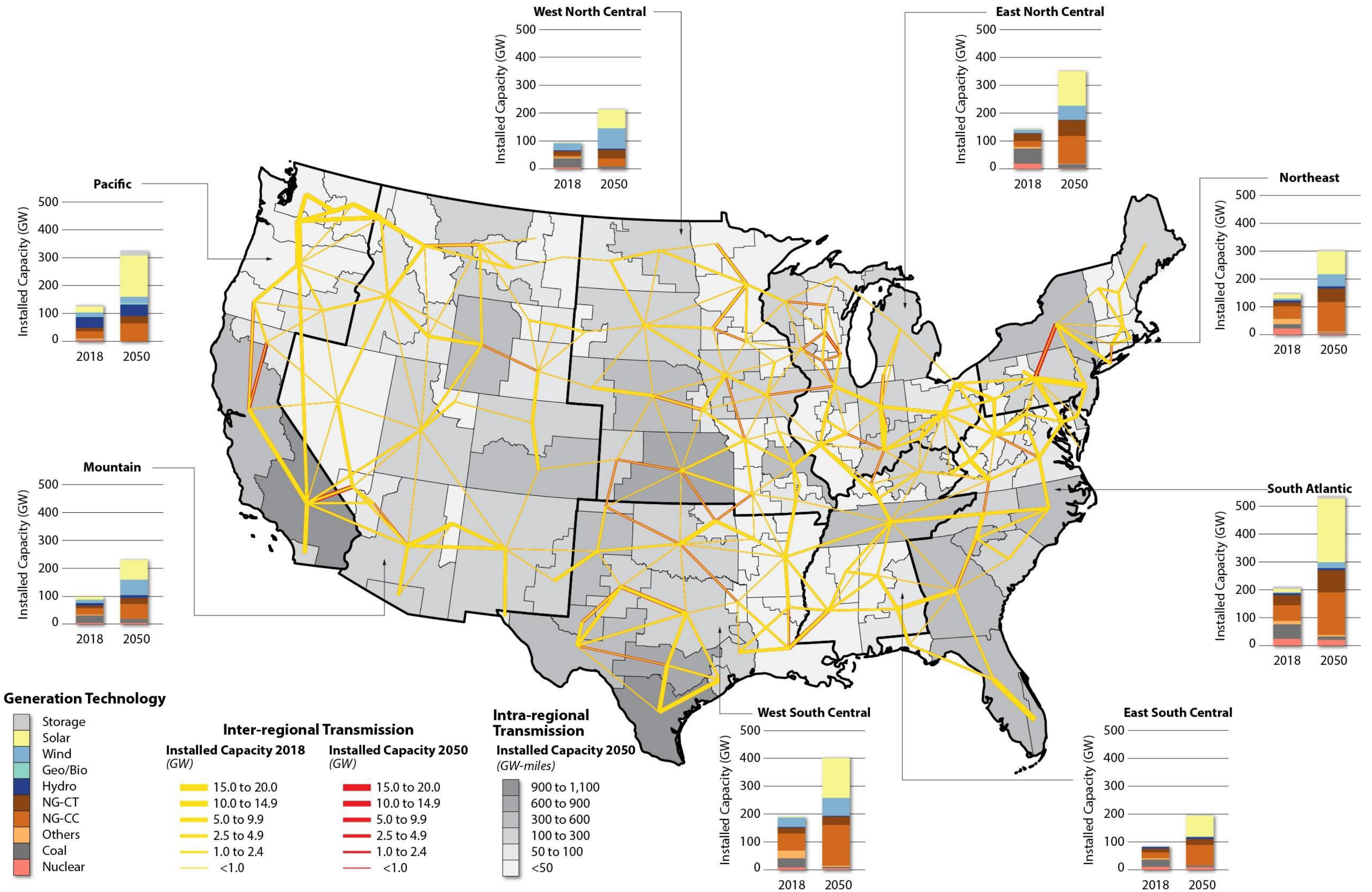

Figure ES-1. Meeting electrified loads requires a doubling of generation capacity in all regions by 2050.

Results presented here are for the High electrification scenario with default assumptions for all supply-side input parameters (Section 2.1). Within a given region, comparison of the stacked bars demonstrates that generation capacity is at least doubled between 2018 and 2050 due to both (1) the increase in annual and peak demand under High electrification and (2) the fact that the new generation capacity does not all contribute fully to planning reserve provisions. The scattered nature of red lines in the figure indicate only modest growth in long-distance transmission over the existing network (yellow lines), comparable to that observed under Reference electrification. New intra-regional, spur-line capacity (shading) represents the majority of new transmission expansion and scales more directly with electrification level.

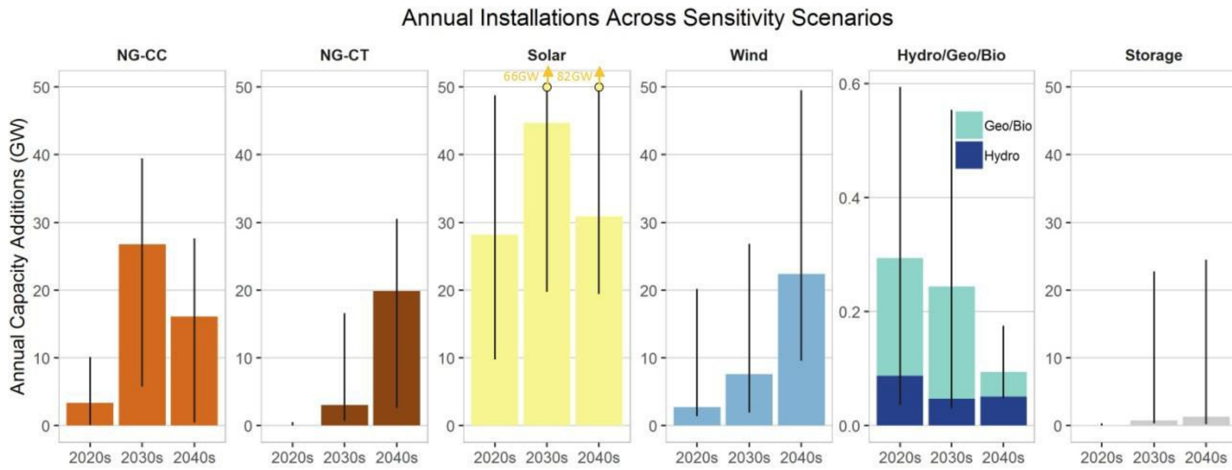

Figure ES-2. Electrification drives an increase in annual generation capacity additions, which primarily take the form of renewable energy and natural gas-fired technologies.

Colored bars reflect results from the High electrification scenario with default assumptions for all supply-side input parameters (Section 2.1). Vertical lines show the full range of results across all High electrification scenarios. Note the different vertical scales.

NG-CC = natural gas combined cycle, NG-CT = natural gas-combustion turbine; Solar comprises photovoltaics and concentrating solar power; Wind comprises onshore and offshore wind; and Storage comprises pumped storage hydropower, compressed air energy storage, and batteries.

High electrification drives the accelerated and increased deployment of both renewable energy and natural gas-fired technologies, with incremental deployment beginning in the 2030s. Growth over time is expected for both natural gas and renewable energy across all supply-side assumptions, but these two sources also compete to supply electricity to increasing demands under electrification.

2. **Electrification inherently increases the reliance of demand sectors on electricity, and it could offer enhanced opportunities for more-active participation from flexible loads in the planning and operations of the electricity system.**

   A. Electrification could open opportunities for increased flexibility from all demand sectors (buildings, transportation, and industry), with the most pronounced effects arising from flexible electric vehicle charging.

   B. Flexible loads can partially mitigate the power sector infrastructure needs and associated costs from electrification, particularly by serving as a resource to meet peak demands and planning reserves.

   C. Flexible loads could support more cost-efficient bulk power system operations. As one example, demand-side flexibility results in reduced curtailments, which indicates that flexible load could support grid integration of variable renewable energy resources.

   D. Without additional demand-side flexibility, high demand peaks from electrification could lead to increased requirements for infrastructure development and greater reliance on other supply-side sources for flexibility.

3. There are abundant resources in the United States with similar costs to meet potential electrification-driven growth in electricity demand.

E. Electrification's effect on both the cost per unit of electricity consumed and bulk electricity prices is modest, because incremental demands are likely met by low-cost natural gas and renewable energy resources.

F. While the United States has sufficient resources to meet future electrification needs, the increased generation and transmission capacity required to meet growing load under widespread electrification intuitively requires an increase in *power* sector expenditures (Figure ES-3) across all scenarios explored. However, the effect of electrification on total *energy* system costs is more complex (see Finding 4).

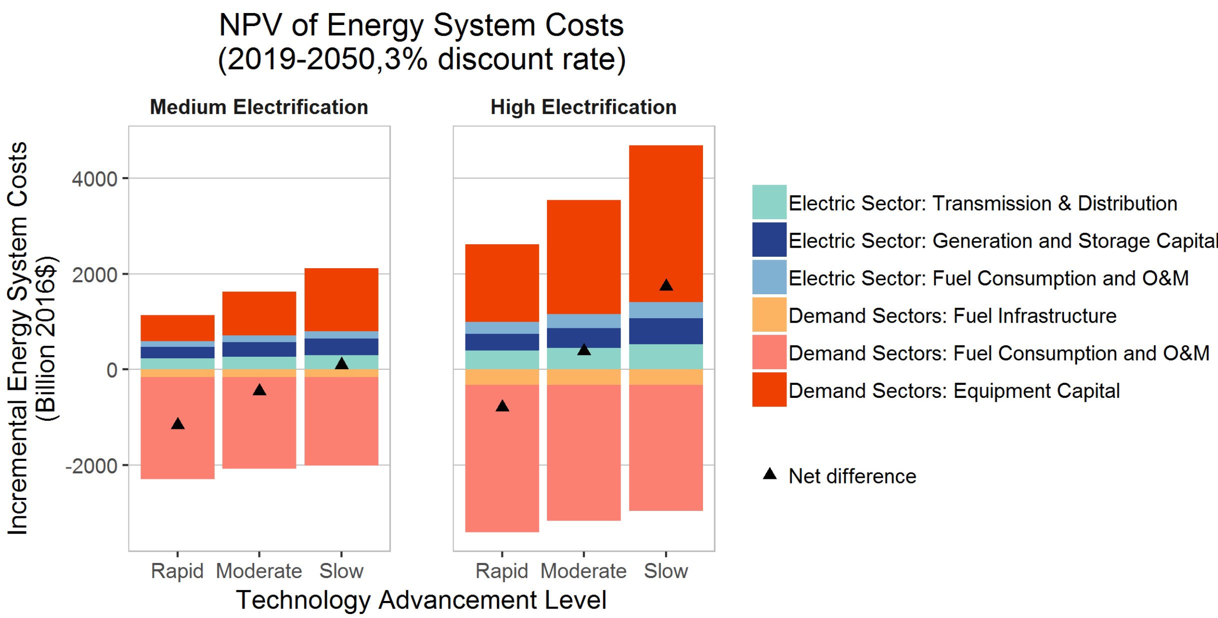

Figure ES-3. Electrification's effects on energy system costs depend strongly on the extent of electrification and the future cost and performance of electric end-use technologies.

The figure shows the incremental energy system costs associated with our Medium and High electrification scenarios, relative to Reference electrification, for three levels (Rapid, Moderate, and Slow) of electric end-use technology advancement. See Section 2.2 for details and additional context.

Within the electric sector (including generation, transmission, and distribution), meeting electrification-driven increases in demand for electricity intuitively drives higher system costs. Within the demand sectors (buildings, transportation, and industry), electrification shifts costs from fuel and operations to capital expenditures. On net, energy-system costs or savings are more sensitive to the level of electrification and advancements in electric end-use technologies than they are to supply-side assumptions (not shown here).

4. **Considering the entire energy sector, the net system cost impact of electrification depends most significantly on future advancements in the cost and efficiency of electric end-use technologies (Figure ES-3).**

   A. Electrification results in an increase in electric sector system costs (3A above) and higher capital expenditures for demand-side equipment. However, these system cost increases are partially or entirely offset by fuel and operational savings in the buildings, transportation, and industry demand sectors.

   B. Electrification can result in net energy system savings when it (1) occurs together with more rapid advancements in the cost and efficiency of end-use electric technologies or (2) extends primarily to more cost-effective technologies and circumstances.

   C. Conversely, when end-use electric technology advancements are limited, electrification results in net energy system cost increases due to several compounding factors: (1) higher capital expenditures are needed for demand sector equipment, (2) direct operational savings of such equipment are more-limited, and (3) greater electric sector expenditures are required if efficiency improvements are slow to materialize.

5. **Electrification reduces direct energy consumption and emissions in the demand sectors and shifts them into the power sector, the net effect of which is energy system-wide reductions in both.**

   A. Because of the energy efficient nature of electric end-use technologies, direct final energy use is lower with widespread electrification. Moreover, even when accounting for the losses associated with the conversion of fuels to electricity as well as transmission and distribution losses, electrification reduces total primary energy consumption (Figure ES-4).

   B. Electrification-driven reductions in energy consumption primarily arise from avoided fossil fuel consumption in the demand sectors, most prominently avoided petroleum consumption from the transportation sector. The impact of electrification on total energy sector natural gas consumption is muted because reductions in end-use natural gas consumption are typically offset by increases in natural gas used for power generation.

   C. The emissions intensities of carbon dioxide, sulfur dioxide, and nitrogen oxides (CO_2, SO_2, and NO_X) associated with electricity generation decline over time and with increasing electrification, as new demand is met from lower-emitting generation sources. However, electricity emissions intensities are sensitive to the future competitiveness of low-emissions generators and power system constraints.

   D. Electrification reduces direct CO_2, SO_2, and NO_X emissions from the demand sectors in total across the contiguous United States. Some of these avoided demand-sector emissions are shifted to the power sector, but the net effect of electrification is an overall reduction in energy sector-wide air emissions (Figure ES-4).

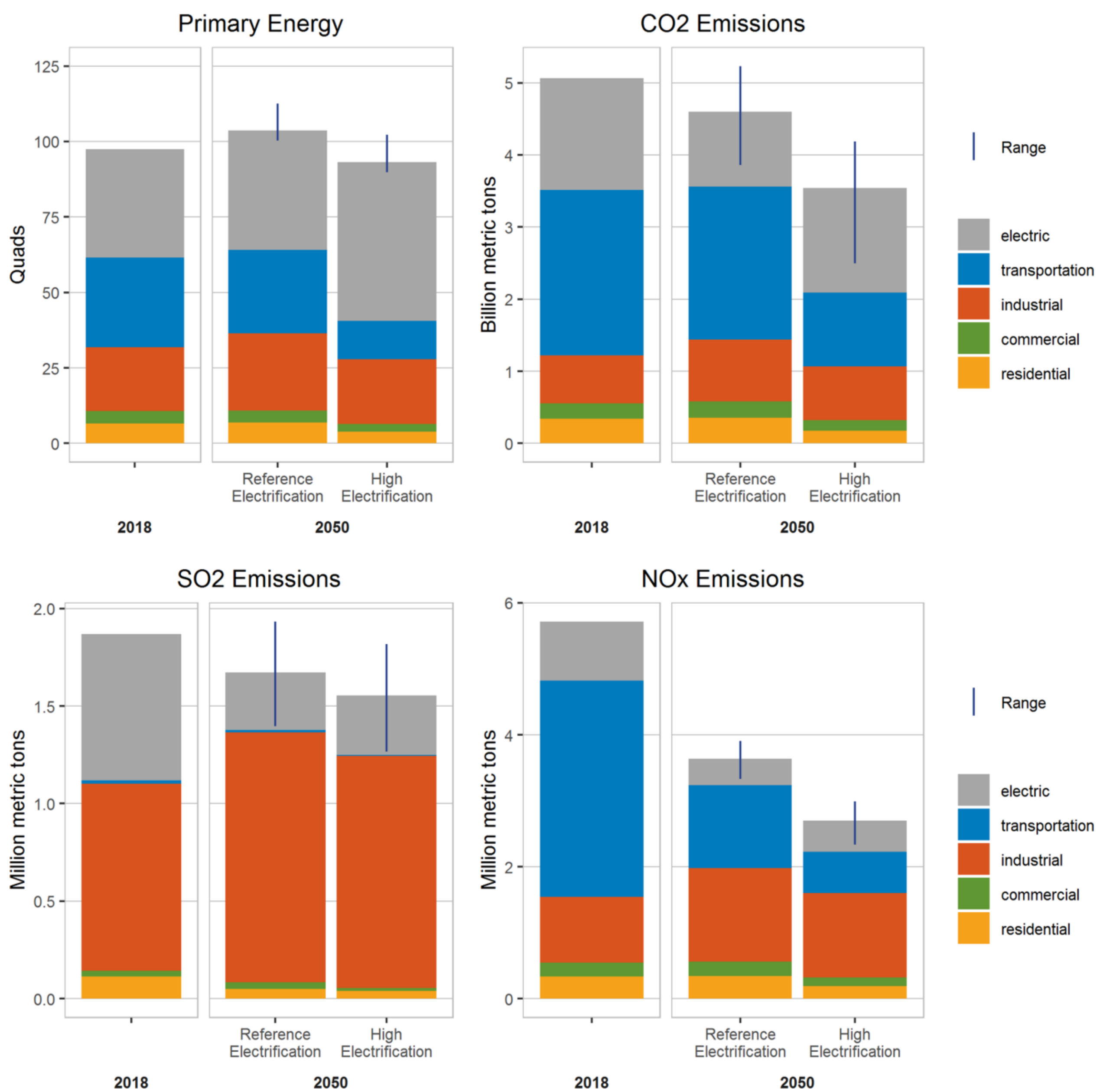

Figure ES-4. Electrification drives a reduction in energy consumption and air emissions, with the magnitude depending strongly on the evolution of the power sector.

Colored bars reflect results from the High electrification scenario with default assumptions for all supply-side input parameters (Section 2.1). Vertical lines show the full range of results across all scenarios, such that the position of a given scenario along the vertical line is similar under both Reference and High electrification results. Note the different vertical scales.

Reference electrification results presented in the figure can be thought of as a business-as-usual trajectory. Therefore, comparison between 2018 and Reference electrification (2050) values demonstrate the effects of an evolving energy sector over time, in the absence of widespread electrification: primary energy consumption increases due to population and economic growth, whereas energy sector emissions decline as the emissions intensities associated with electricity generation and end-use technologies decline. Comparison between Reference and High electrification values (both in 2050) demonstrate the isolated impacts of electrification, which include reductions in primary energy and all air emissions types evaluated in this study.

The core insights listed above are derived from the modeling and analysis conducted. However, we acknowledge that several scope and methodological limitations exist in the tools and approach used. Here, we highlight and summarize some of the gaps in our analysis, many of which could influence the outcomes and key findings:

- The estimated extent of generation and transmission infrastructure expansion under increasing electrification could introduce challenges related to materials availability, supply chains, and/or permitting and siting, which are not explicitly considered.
- The EFS scenario analysis does not analyze all factors that could influence future amounts of electricity and service demand, which could alter the estimated infrastructure needs. In particular, this analysis does not consider the interactions of electrification with other forms of energy efficiency, distributed energy resources, and hydrogen fuel production and other seasonal storage options. It also does not estimate the impacts of climate change on generation resources, power plant efficiency, and electricity demand.
- The modeling applies a contiguous-U.S., system-wide framework with regional detail; more research is needed to assess the economic and noneconomic trade-offs between local and remote resources. Furthermore, the modeling does not consider impacts of electrification on international trade of energy products (e.g., liquefied natural gas and petroleum products).
- Our analysis does not fully evaluate the interactions and trade-offs between transmission, storage, and flexible load for different generation portfolios that are needed under widespread electrification. In addition, we do not explicitly represent the cost of implementing and accessing demand-side flexibility—or all of the associated behavioral and technical constraints—which are not well known.
- Our analysis includes power and energy *system* costs of electrification, but it does not assess consumer expenditure or distributional economic impacts for different stakeholders—including households, businesses, manufacturers, or energy suppliers and distributors. These impacts will depend strongly on local factors that influence both energy rates and consumer expenditures.
- We report select air emissions estimates for the modeled scenarios, but we do not conduct a thorough evaluation of the consequential health and environmental impacts, which would require regional and local assessments, as well as a full life-cycle assessment of the emissions included in this study and a broader set of air and water impacts.

Other limitations of our analysis are discussed in the main body of the report and the companion methods-focused report (Sun et al. 2020). Assessments of electrification are difficult due to its complex nature—namely the inherent cross-sectoral interactions and the emergence of new electricity loads with their own unique attributes—and the uncertainties in any long-term forward-looking analysis. Nonetheless, our modeling and analysis identify key trends and provide quantitative estimates of the potential impacts of electrification. These initial findings can help inform future research and can also provide decision-makers with estimates of potential power systems implications of a future in which electricity powers an expanded share of the U.S. energy economy.

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1 Introduction

Electrification is an emerging trend in energy markets around the world, which involves the shift from any non-electric source of energy to electricity at the point of final consumption. Electrification is primarily being driven by a collection of newly improved electric end-use technologies, interest from consumers and manufacturers, and a variety of policy objectives, including air pollution reduction and climate change mitigation. Depending on the magnitude and extent of electrification, such a transition could require a rapid and extensive response from the power system, which would be heavily relied upon to meet electricity's increasing share of end-use energy consumption.

This report, the fifth in the Electrification Futures Study (EFS) series,[3] explores the potential impacts of electrification on the future U.S. power system. Specifically, the analysis presented in this report is designed to address the following questions:

- What are the impacts of electrification on the mix, magnitude, location, and timing of new bulk power system infrastructure development in the United States?
- How could widespread end-use electrification impact the generation mix and utilization of different classes of generators and transmission assets?
- What are the impacts of electrification on costs, energy consumption, and air emissions for the electric and broader energy systems?

To develop initial answers to these questions, we conduct a detailed power system analysis using models that simulate the future evolution of the electricity sector of the contiguous United States. This modeling analysis relies on input from prior EFS analyses regarding how the timing and magnitude of end-use energy consumption patterns could change under increasing levels of electrification. Moreover, some of the results—particularly those regarding net impacts for the broader energy system—rely on a combination of (1) results from the power sector modeling conducted here and (2) modeling of the demand sectors previously conducted as part of the EFS (Mai et al. 2018).[4] Specific linkages between EFS analyses are described below.

Our analysis applies a scenario approach to isolate and assess the impacts of electrification. In this section, we provide an overview of the modeling used to simulate the scenarios along with a description of the scenario framework and assumptions. A subset of the scenarios presented in this report were also included in Murphy et al. (2020).

[3] An accompanying journal article (Murphy et al. 2020) presents a subset of the results included in this report.
[4] For a current list of EFS publications and more information about the EFS project, see "Electrification Futures Study," NREL, https://www.nrel.gov/analysis/electrification-futures.html.

1.1 Modeling Overview

The NREL Regional Energy Deployment System (ReEDS) model (Cohen et al. 2019; Cole, Frazier et al. 2018) serves as the analytic backbone of this analysis.[5] ReEDS is a capacity planning and dispatch model that simulates electricity supply scenarios for the contiguous United States through 2050.[6] It uses system-wide optimization to find the least-cost portfolio of generation, transmission, and storage options that meet numerous constraints, including electricity balancing and reserve requirements, resource constraints, and policy requirements. The model only explicitly represents the *bulk* power system infrastructure, so the ReEDS results presented in this report exclude the distribution system for the most part.[7]

A unique feature of ReEDS is its high spatial resolution, which includes 134 modeled balancing areas and 356 renewable energy resource regions (Figure 1, page 3). These modeled balancing areas are connected by inter-regional transmission lines, and they can be aggregated up to state and regional transmission organization footprints,[8] which are used to specify local constraints and requirements (e.g., state-level policies and operating reserve constraints). The model's high spatial resolution enables it to represent the dispersed and location-restricted characteristics of renewable energy technologies and variations in the magnitude and temporal shape of electricity consumption between demand centers.

Because the adoption and performance of electric end-use technologies can be affected by local conditions, ReEDS is particularly well-suited to assess the impacts of electrification-driven changes in electricity demand. For example, the efficiency of, and corresponding power demands from, air source heat pumps vary with ambient temperatures, which depend on local weather patterns (Jadun et al. 2017). Other local factors include the amount of services demanded in each region and the makeup of the existing equipment stock.

Although the detailed network representation in ReEDS makes it well-suited to represent geographically varying factors related to electrification, we apply methodological changes to improve the model's representation of other electrification-specific factors for the EFS analysis. These modifications include (1) improving the representation of load shapes and high demand periods, particularly in the winter season; (2) representing how changes in direct end-use natural gas consumption could impact the economics of natural gas-fired generation; and (3) developing

[5] The ReEDS model used for this analysis is modified from the 2018 final release version of ReEDS (Cohen et al. 2019), which was used for NREL's 2018 Standard Scenarios report (Cole, Frazier et al. 2018) and includes technology cost and performance data from the 2018 Annual Technology Baseline (2018 ATB; NREL 2018). A recent analysis (Cole and Vincent 2019) compares historical capacity build decisions and ReEDS investment decisions.

[6] Other versions of ReEDS include explicit representation of the full North American power system, and they can be used to develop scenarios through 2100. ReEDS can also model climate impacts on electricity demand and supply (Sullivan, Colman, and Kalendra 2015; Cohen et al. 2014), but this capability was not employed here.

[7] The ReEDS results do account for distribution system losses, and they include distributed photovoltaic capacity, but the underlying customer adoption was determined using the Distributed Generation Market Demand Model (DGen) model (Sigrin et al. 2016). No other distributed generation technologies are represented.

[8] *Modeled* balancing areas are informed by, but do not align with, current or historical balancing authority areas in the United States. Similarly, *modeled* regional transmission organizations closely overlap with *actual* regional transmission organizations and with independent system operator footprints where they exist and represent fictitious reserve-sharing groups for regions without restructured markets (Cohen et al. 2019).

a new model representation of demand-side load flexibility. These changes are documented in a companion EFS report (Sun et al. 2020).

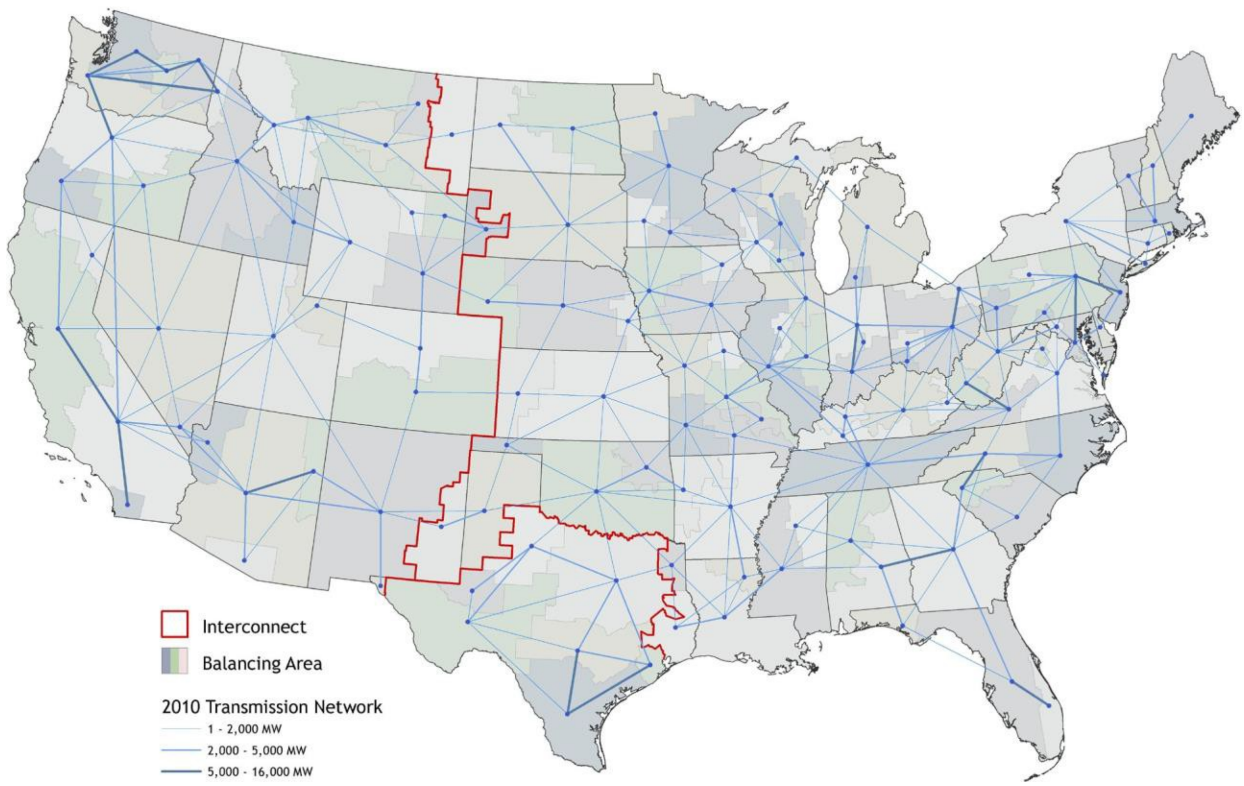

Figure 1. ReEDS spatial structure and network representation.

Transmission lines shown in blue reflect the existing transmission interface capacities between model balancing areas. The red lines denote boundaries between the three interconnections in the contiguous United States.

In this report, results and findings for the bulk power system are based on outputs from the ReEDS model; however, we also report estimates for impacts to the broader energy system. For these estimated impacts, we rely on a combination of the ReEDS power sector scenario outcomes and those for the demand sectors (presented in an earlier EFS report, Mai et al. 2018), which were developed using the EnergyPATHWAYS model.[9] Combining results from ReEDS and EnergyPATHWAYS allows us to analyze a wide set of potential energy sector-wide impacts of electrification in detail, each of which is approached with a high level of granularity in terms of technology, spatial, and temporal resolution.

However, all models have limitations, and the complexities of electrification—including its potential far-reaching impacts across all sectors and how it enhances coupling between sectors—makes any comprehensive model representation difficult. Appendix A outlines some key caveats and limitations of the present study and broader EFS analysis, the impacts of which can only be assessed in detail through dedicated future research. For these reasons, EFS scenarios should not

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[9] EnergyPATHWAYS" https://github.com/energyPATHWAYS/EnergyPATHWAYS.

be interpreted as predictions. Rather, this analysis is designed to develop insights and quantifications of the potential impacts of widespread electrification on the bulk power system by using a high spatial resolution, national-scale capacity expansion model of the contiguous United States.

1.2 Scenario Framework

We apply a scenario analysis approach that explores the impacts of electrification across multiple dimensions. The primary dimension is the level of electrification, which affects both the magnitude and timing of electricity consumption. In particular, we explore the three EFS electrification scenarios established by Mai et al. (2018), which are defined by different levels of electric end-use technology adoption:[10]

- **Reference electrification** *represents the least incremental change in electrification through 2050, which serves as a baseline of comparison to the other scenarios*.[11] Electricity's share of final energy (Figure 2, page 6) grows modestly over the next three decades, primarily due to the continued adoption of electric heat pumps to serve space heating needs in buildings and modest growth in light-duty electric vehicle adoption.
- **Medium electrification** *represents widespread electrification in select sub-sectors with potentially lower barriers, but it does not result in transformational change*. Electricity's share of final energy grows by approximately 50% over the next three decades, primarily due to an increase in transportation electrification, especially for light-duty vehicles. This scenario also assumes the continued adoption of electric technologies for space and water heating, cooking, and clothes drying in buildings,[12] but reliance on other fuels to meet buildings services persists through 2050. Adoption of industrial electric technologies is limited to applications with potential productivity benefits only.
- **High electrification** *represents transformational change in electricity's share of final energy consumption, such as that which could result from a combination of technology advancements, policy drivers, and consumer enthusiasm for electric technologies*. Electricity's share of final energy nearly doubles over the next three decades due to the adoption of electric technologies in all major end uses. For example, this scenario involves aggressive electrification assumptions across all on-road vehicle classes, and electric technologies serve nearly all major buildings services in all U.S. regions as several technical, economic, behavioral, and other challenges are overcome. Electrotechnology adoption is also assumed to be more widespread in industry.

[10] The EFS demand-side scenarios from Mai et al. (2018) were developed using an energy and stock-rollover accounting model, EnergyPATHWAYS. In all the scenarios modeled, the adoption of end-use electric equipment occurs at the end of the assumed lifetime of the previous equipment; they do not allow for "premature" replacements. Technology sales shares in each given year were inputs to the model and were based on a combination of expert opinion and modeling. See Mai et al. (2018) for details.

[11] Assumptions about the demand side in the Reference scenario are largely consistent with the U.S. Energy Information Administration's AEO2017 Reference case, which reflects laws, policies, and regulations as of 2017. The supply-side modeling presented here uses many core assumptions from the AEO2018.

[12] The adoption of electric end-use technologies in buildings under Medium electrification primarily occurs in new buildings, but it also occurs in beneficial retrofit applications (e.g., the displacement of fuel heating oil).

Note that the underlying assumptions about *service* demand for all energy end uses remain unchanged across the Reference, Medium, and High electrification levels, and they reflect the population and gross domestic product (GDP) growth assumptions in the U.S. Energy Information Administration's Annual Energy Outlook for 2017 (AEO2017) (EIA 2017). The similar level of service demand facilitates an isolation of the effects of electrification, but some potential behavioral and economic dynamics associated with electrification are not captured in such a framework (see Appendix A).

Figure 2 summarizes the resulting variation in annual electricity demand and electricity's share of final energy across the Reference, Medium, and High electrification levels, which will be denoted as such throughout the remainder of this report. These summary values were derived from the scenario-specific hourly electricity demand profiles, which serve as the input into ReEDS (Sun et al. 2020) for the present report. To provide context for the levels of electrification considered here, Table 1 provides select indicators from the demand sectors, and Mai et al. (2018) provides details regarding these electrification levels. Note that both Figure 2 and Table 1 are meant to provide intuition for the analysis presented here, but they should not be interpreted as bounding values; indeed, other studies have explored a broad range and extent of electrification (EPRI 2018a; Williams et al. 2015; The White House 2016; Weiss et al. 2017; Iyer et al. 2017; Steinberg et al. 2017), some of which involved higher levels of electricity demand and shares of final energy.

Table 1. Select Metrics to Characterize the Electrification Levels Explored in this Analysis[a]

		Demand-Side Adoption Scenario Results for 2050		
Electrification Metric	**2018**	**Reference Electrification**	**Medium Electrification**	**High Electrification**
Electricity's share of space heating services	12%	17%	38%	61%
Electricity's share of water heating services	26%	26%	39%	52%
Share of transport miles from electric vehicle miles traveled	<1%	8%	52%	76%
Light-duty plug-in electric vehicles (number and % of fleet)	~1 million (<1%)	30 million (11%)	186 million (66%)	242 million (84%)
Electricity's share of industrial curing needs	0%	0%	15%	63%

[a] Results are based on the demand-side adoption scenarios in Mai et al. (2018). These metrics do not vary with the assumed level of end-use technology advancement.
[b] Groom 2017

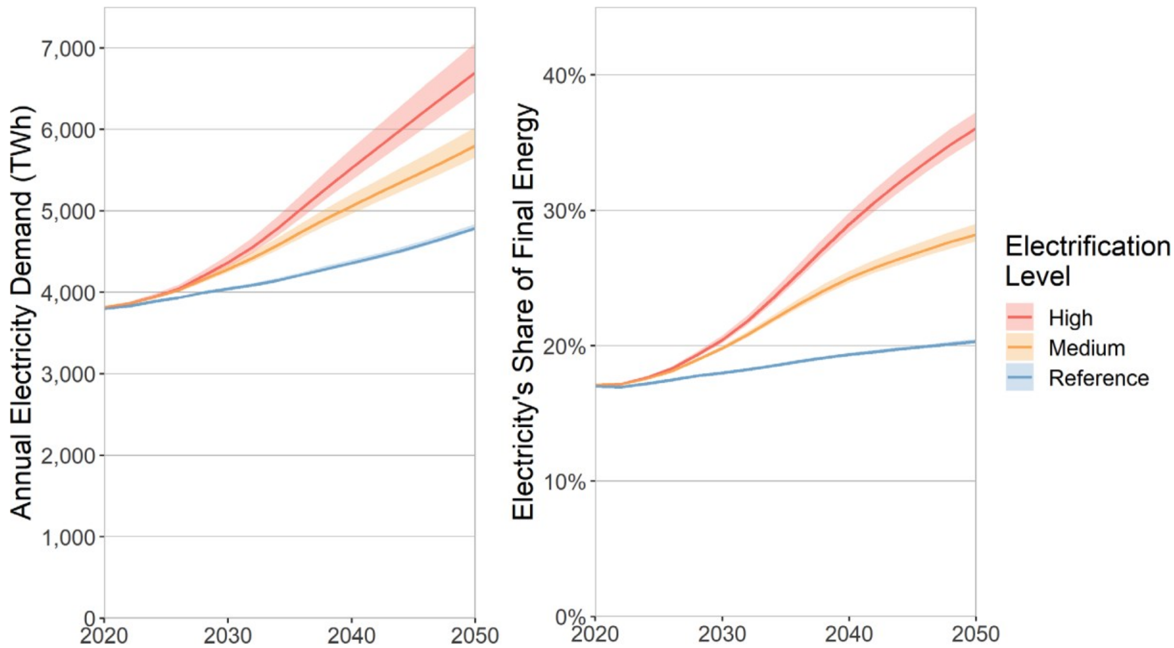

Figure 2. Annual end-use electricity demand (left) and electricity's share of final energy (right) for the three electrification levels evaluated in this study (thick solid lines).

Shaded regions around the solid lines reflect the magnitude of impact associated with the range of end-use technology advancement explored by Mai et al. (2018) and in the present study. Numerical values differ from those reported by Mai et al. (2018) due to minor adjustments in electricity demand (Sun et al. 2020) and to differences in the scope of subsectors included in the final energy demand estimates (see Section 2.3.2).

TWh = terawatt-hour.

Our presentation of results often emphasizes comparison across scenarios with different levels of electrification. In particular, we refer to differences between two scenarios that have (1) varying levels of electrification but (2) the same input assumptions for the electric sector as the *incremental* impacts of electrification.[13] The primary purpose of these incremental results is to isolate the unique electrification-driven changes from those that are driven by different electric system (or supply-side) assumptions.

In addition to the incremental measures reported, we also present results reflecting the *cumulative* impacts of electrification. These results refer to changes in the power system compared to 2018 levels, and they provide insights into the magnitude and type of change that could occur over time with increasing levels of electrification. The primary purpose of these estimates is to help inform electric and energy system planning that could accompany widespread electrification.

Although the electrification level is the primary dimension varied, we also examine variations in other dimensions, including demand-side and supply-side input assumptions (Figure 3). Unless otherwise noted, Base Case or default assumptions are used in the scenarios, where we

[13] In other words, incremental values refer to differences between a High (or Medium) electrification scenario and the corresponding Reference scenario.

typically only vary a single set of assumptions at a time. Key assumptions in the Base Case are largely consistent with the Mid-Case of the *2018 Standard Scenarios Report* (Cole, Frazier et al. 2018),[14] and they are summarized in Table 2.[15] For clarity and throughout the report, we apply our scenario naming convention, which identifies whether the Base Case or other assumptions are used as well as the electrification level. For example, “Base Case with High electrification” refers to the scenario with High electrification and default assumptions for all other inputs.

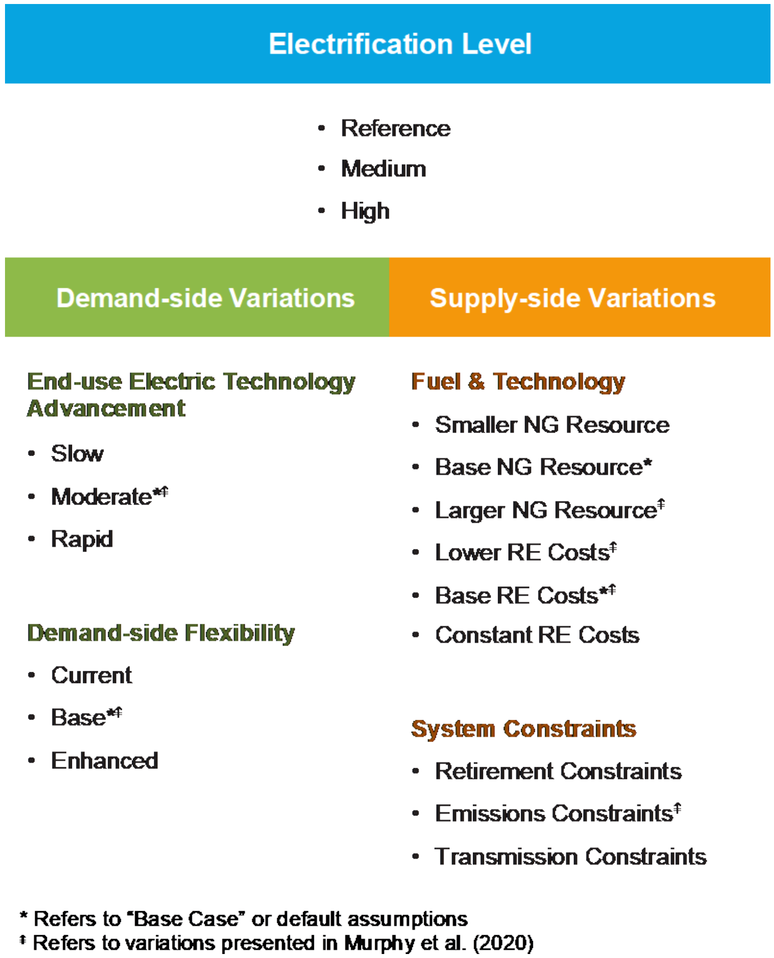

Figure 3. Input assumption dimensions varied across scenarios

NG = natural gas. RE = renewable energy.

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[14] The annual Standard Scenarios report presents an outlook of the U.S. electricity sector based on a suite of standard scenarios with associated supply-side assumptions. For more information, see “Annual Technology Baseline and Standard Scenarios,” NREL, https://www.nrel.gov/analysis/data-tech-baseline.html. Our Base Case with Reference electrificationis most similar to the Standard Scenarios 2018 Mid Case, although minor differences exist as a result of the model improvements described by Sun et al. (2020).

[15] Table 2 also identifies the underlying source documents for details about the assumptions, and Appendix B includes tabular data on the generation technology cost and performance assumptions.

Table 2. Base Case Default Assumptions

Parameter	Source	Description
Electric end-use technologies	EFS Moderate Advancement (Jadun et al. 2017)	Heat pump and electric vehicle technologies advance steadily due to additional research and development (R&D) and learning by doing, with 2050 levelized costs of driving (for electric vehicles) and heating (for air source heat pumps) reduced by 11%–44% and 20%–35%, respectively, from 2018 levels.
Demand-side flexibility	EFS Base flexibility (Sun et al. 2020)	Demand-side flexibility grows in all regions and sectors to participation levels that resemble successful utility programs today. The amount of flexible load varies with electrification level and ranges from 2% to 5% of total annual load.
Natural gas resource[a]	AEO2018 Reference (EIA 2018a)	The AEO2018 scenarios rely on assumptions of the “technically recoverable crude oil and natural gas resources.” EFS modeling endogenously considers natural gas prices based on these resource assumptions and scenario-specific estimates of gas consumption in the energy system (see Sun et al. 2020 for the methods used).
Renewable energy technologies[a]	Annual Technology Baseline (ATB) 2018 Mid (NREL 2018)	Technology advances through continued industry growth, public and private R&D investments, and market conditions relative to 2018 levels that may be characterized as “not surprising.”[b] Between 2017 and 2050, the levelized cost of energy for onshore wind and utility-scale solar photovoltaics are reduced by 28% and 39%, respectively.
Battery storage technologies[a]	Mid case (Cole, Marcy et al. 2016)	Battery cost trajectories are based on median cost reductions from a collection of published studies at the time. Battery system capital costs decline to about $270/kWh by 2050 for four-hour systems.[a]
Plant retirements	ReEDS default (Cohen et al. 2019)	ReEDS models retirements based on announcements, lifetimes, and utilization.[c] Assumed lifetimes for fossil plants are from ABB (2018): coal plant lifetimes are either 65 or 75 years (depending on plant size), and natural gas combustion turbine and combined cycle plant lifetimes are both assumed to be 50 years. Nuclear plant lifetimes are either 60 or 80 years. Wind and solar lifetimes are assumed to be 24 and 30 years respectively.
Transmission	ReEDS default (Cohen et al. 2019)	Power transfers and transmission expansion are endogenously modeled. Transmission losses are assumed to be 1% per 100 miles (plus an additional 5.3% in distribution losses). Transmission costs—for inter-regional long-distance lines and intra-regional interconnections—vary by region.
Policies[d]	2018 Standard Scenarios (Cole, Frazier et al. 2018)	Existing policies as of spring 2018 include the federal tax credits for renewable energy technologies and carbon oxide sequestration, state renewable portfolio standards, and carbon emissions policies for California and the Regional Greenhouse Gas Initiative states.

[a] These assumptions represent the most up-to-date information at the beginning of the EFS ReEDS analysis, but more recent projections have trended towards lower future natural gas prices, renewable energy costs, and battery costs. For example, future cost trajectories in Cole, Marcy et al. (2016) were based on expectations before 2016, but battery technologies have advanced considerably since then.

[b] The description is directly from NREL (2018). Appendix B includes details on technology assumptions that are used in the present modeling, as ReEDS does not base its decision on the levelized cost of energy (LCOE).

[c] Utilization-based retirements are modeled for coal plants only.

[d] The representation of existing policies includes changes in policies as legislated at the time of this analysis (e.g., the federal wind production tax credit ramp down and expiration by the end of 2019, and the scheduled step-down of the federal investment tax credit). The emergence of, and revisions to, several state policies have occurred since spring 2018, and they are not included in this analysis. For details about the policies represented and the methods used to represent them, see the model’s documentation (Cohen et al. 2019).

Section 2 presents results from across the Base Case scenarios with all three levels of electrification, along with variations in the future cost and performance of electric end-use technologies (Jadun et al. 2017). Key results include the electrification-driven evolution of the bulk electric system (in terms of its infrastructure and system costs), as well as estimated impacts on energy system-wide costs, energy consumption, and air emissions. Section 3 focuses on the availability of demand-side flexibility (i.e., load shifting) across different levels of electrification. Section 4 explores how sensitive the cumulative and incremental effects of electrification are to variations in electric sector input assumptions, including fuel prices, technology costs, and system constraints (Table 3).[16] In total, 29 scenarios of bulk electric system evolution are presented in this report,[17] and the corresponding ReEDS results are available for exploration and download via our scenario viewer.[18] We conclude in Section 5 with the key findings of the analysis based on the full collection of scenarios and a discussion of future research needs.

Table 3. Scenario Categories and Parameter Dimensions

Category	Dimensions
End-use technology variations (Section 2)	Variations across all electrification (Reference, Medium, and High) and electric end-use technology advancement (Slow, Moderate, and Rapid) levels are explored, with Base Case assumptions being followed for all other parameters.
Demand-side flexibility variations (Section 3)[a]	Variations across three levels of flexible load (Current, Base, and Enhanced)[b] are explored across Reference and High electrification, with Base Case assumptions being followed for all other parameters.
Electric sector variations (Section 4)[a]	Variations in the natural gas resource, renewable energy and storage technology costs, and system constraints are explored across Reference and High electrification, with Base Case assumptions being followed for end-use technology advancement and demand-side flexibility levels.

[a] These categories include the Reference and High electrification levels (under Moderate end-use electric technology advancements). Select scenarios from Section 4 were also presented in Murphy et al. (2020).

[b] ReEDS' representation of flexible load, including assumptions of the quantity and constraints to the flexibility, is presented by Sun et al. (2020).

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[16] Note that Sections 3 and 4 include scenarios with (1) Reference electrification and Moderate end-use technology advancement and (2) High electrification and Moderate end-use technology advancement. Medium electrification, Rapid end-use technology advancement, and Slow end-use technology advancement are omitted to limit the number of scenarios while still capturing a wide range of electrification impacts.

[17] Sun et al. (2020) present additional scenarios used to demonstrate the effects of the ReEDS model improvements developed for the EFS.

[18] ReEDS model results for this study are available for viewing and download at https://cambium.nrel.gov/?project=fc00a185-f280-47d5-a610-2f892c296e51.

2 Results: End-Use Technology Variations

This section explores how electrification could influence the future evolution of the electric system and, in turn, have broader impacts across the energy system. Assuming default values for all supply-side inputs (i.e., the Base Case assumptions in Table 2), we assess electrification-driven changes by modeling and comparing results across scenarios with different electrification levels (Reference, Medium, and High). Beyond this general electrification dimension—which is defined by end-use technology *adoption*—the efficiency of electric end-use equipment will also affect the aggregate load profiles and, in turn, the associated buildout of the electric system. To facilitate evaluation of this interaction, we explore three end-use technology advancement trajectories (Slow, Moderate, and Rapid) from Jadun et al. (2017) for select technologies:[19]

- The **Rapid** end-use technology advancement trajectory is consistent with futures in which R&D investment spurs technology innovations, manufacturing scale-up increases production efficiencies, and consumer demand and public policy yields technology learning.
- The **Moderate** end-use technology advancement trajectory reflects electric end-use technology progress beyond current trends through additional R&D and technology innovation.
- The **Slow** end-use technology advancement trajectory represents futures where electric technology progress follows current trends without major advances.

A detailed presentation of how the nature and magnitude of assumed technology advancements vary by sector and technology can be found in Jadun et al. (2017). Here, we summarize these technology advancement levels in Table 4, based on their aggregate impact on annual consumption and peak demand in 2050. The values in Table 4 define the range of efficiency measures we explore in this analysis, but variations in other end-use electric technologies, a broader set of energy efficiency measures, and the potential emergence of new electricity-consuming industries could all yield a wider range for future electricity demand (as discussed by Mai et al. 2018).

[19] The technologies whose cost and performance vary across the Rapid, Moderate, and Slow end-use technology advancement trajectories include plug-in hybrid and battery electric light-duty cars and trucks, battery electric transit buses and medium- and heavy-duty trucks, and air source heat pumps for space and water heating in buildings. These trajectories represent a range of future efficiency and cost advancement possibilities, but they are not bounding estimates.

Table 4. Summary of Relevant Demand-Side Input Assumptions Regarding Electricity Demand

	Electrification Level	End-Use Technology Advancement[a]	Annual Demand (TWh)[b]	Annual Demand (CAGR, 2018–2050)[b]	Peak Demand (GW)[c]	Peak Demand (CAGR, 2018–2050)[c]
2018[d]			3,710	n/a	670	n/a
2050	Reference	Rapid	4,760	0.8%	850	0.8%
		Moderate	4,790	0.8%	860	0.8%
		Slow	4,840	0.8%	880	0.9%
	Medium	Rapid	5,660	1.3%	1,080	1.5%
		Moderate	5,800	1.4%	1,130	1.7%
		Slow	6,030	1.5%	1,220	1.9%
	High	Rapid	6,460	1.8%	1,250	2.0%
		Moderate	6,700	1.9%	1,320	2.2%
		Slow	7,060	2.0%	1,450	2.5%

[a] The technology advancement trajectories are from Jadun et al. (2017).

[b] Demand values represent end-use consumption. The total amount of generation required in the model will exceed these values because of transmission and distribution losses. Transmission losses are endogenously represented in the model and depend on the amount and distance of energy transfers. Distribution losses are assumed to be 5.3% in all years, regions, and scenarios. CAGR = compound annual growth rate and TWh = terawatt-hours.

[c] National coincident peak demands are presented. Planning reserves are modeled at a regional level. The peak demand shown does not reflect any demand-side flexibility (see Section 3).

[d] The 2018 values correspond to the default 2018 load profile used in this version of ReEDS.

2.1 Electric System Evolution

To provide a foundation for the presentation of electrification-driven changes, Figure 4 shows capacity and generation mix results for the Base Case scenario with Reference electrification. Under this reference scenario, total installed capacity is relatively flat throughout the 2020s (left panel of Figure 4), primarily due to the current excess capacity in many U.S. regions (NERC 2018). Capacity additions begin to increase by the 2030s and beyond, such that total installed capacity in 2050 is 58% greater than 2018 levels (left panel of Figure 4). This capacity growth primarily takes the form of new solar, wind, and natural gas-fired technologies, which are deployed to meet increasing demand and replace retiring generators.[20] The same technologies also make up the majority of new generation, which grows by 30% between 2018 and 2050

[20] The version of the ReEDS model used for this analysis includes only exogenous retirements for nuclear power plants, most of which are assumed to retire at the end of their existing Nuclear Regulatory Commission operating licenses. Coal-fired power plants are subject to both lifetime- and utilization-based retirements, where the latter occurs in the model if a plant's capacity factor falls below a threshold that varies over time (Cohen et al. 2019). Lifetime-based retirements, which are derived from the ABB Velocity Suite data, range from 65 to 75 years (Table 2). The relative shares of lifetime-based retirements and utilization-based retirements are not available from the model results because of interactions between them.

(right panel of Figure 4) due to service-demand increases associated with population and economic growth. The relative growth in capacity versus generation for a given technology type indicates either lower available capacity factors (for solar photovoltaic [PV] and wind technologies) or the increasing value associated with capacity services (for the natural gas combined cycle [NG-CC] technology).

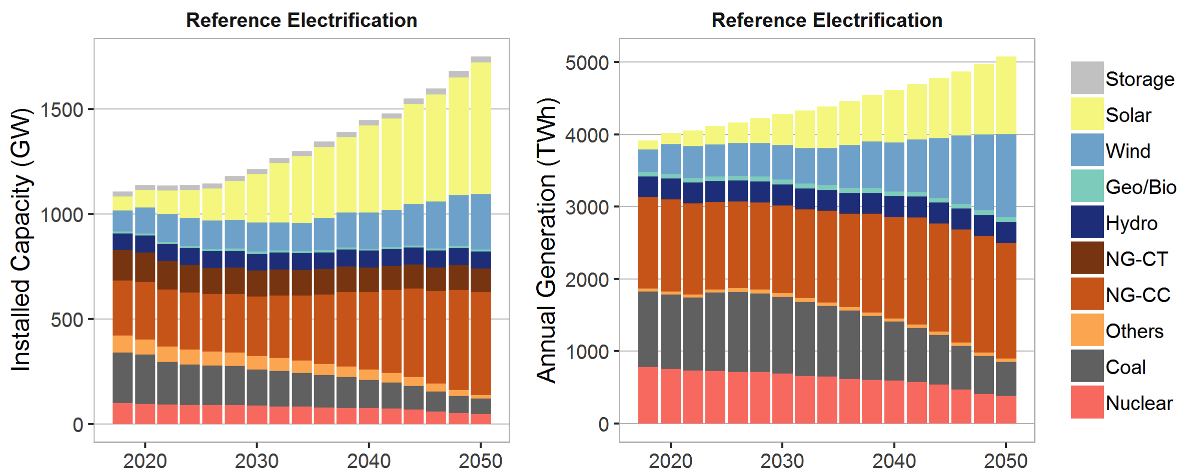

Figure 4. Mixes of capacity (left) and generation (right) under the Base Case with Reference electrification and Moderate end-use technology advancement

Results from this figure were also presented in Murphy et al. (2020).

Holding electric system input assumptions fixed at Base Case values (Table 2),[21] the remainder of Section 2.1 explores how the evolution of electric system infrastructure differs across nine scenarios comprising three levels of electrification and three levels of electric end-use technology advancement.

2.1.1 Infrastructure Deployment

Medium and High electrification require additional electric system infrastructure deployment, beyond that observed under Reference electrification. Electrification-driven growth in total installed capacity begins around 2030 and grows over time, such that installed capacity in 2050 is at least double 2018 levels. Comparing total installed capacity (i.e., in units of gigawatts [GW]) across electrification levels, we find that Medium and High electrification drive an additional 400–600 GW and 700–900 GW (respectively) in 2050, beyond that observed under Reference electrification (Table 5).

The range of results presented for a given level of electrification reflects different assumptions about end-use technology advancement (see Table 4), which indicates that the required electric system infrastructure response to electrification depends strongly on the ultimate load shapes and

[21] While all power sector resource, technology, and policy assumptions are held constant across the scenarios in this section, additional features of electrification change across them, including the load profile shapes, magnitude of flexible load, and price elasticity for natural gas (Section 1.2). All these electrification-related features contribute to differences across the Base Case scenarios, beyond the impact of changing annual demand.

annual loads. For example, cumulative installed capacity in 2050 is 2,280 GW under Medium electrification with Slow end-use technology advancement, compared to 2,320 GW under High electrification with Rapid end-use technology advancement (Table 5). These similar levels of electric system infrastructure buildout occur despite the fact that the High electrification scenario accommodates roughly 30% more light-duty plug-in electric vehicles in 2050 (which represents only one example of end-use technology adoption differences across electrification levels).

Table 5. Cumulative Installed Capacities (GW) and Percentage Changes Over Time

Electrification Level	End-Use Technology Advancement Level[a]	2030	2040	2050	Percentage Change: 2018–2050[b]
Reference	Rapid	1,180	1,370	1,660	51%
	Moderate	1,190	1,400	1,670	52%
	Slow	1,220	1,410	1,710	56%
Medium	Rapid	1,290	1,680	2,040	85%
	Moderate	1,330	1,780	2,240	104%
	Slow	1,370	1,810	2,280	107%
High	Rapid	1,260	1,790	2,320	111%
	Moderate	1,310	1,910	2,440	122%
	Slow	1,400	2,050	2,650	140%

[a] Electric end-use technology advancement trajectories are from Jadun et al. (2017).

[b] The percentage change between 2018 and 2050 is calculated based on the 2018 installed capacity in the ReEDS model, which is 1,100 GW under all Base Case scenarios presented in the table.

Similar to the trends observed in Figure 4, most of this electrification-driven growth in installed capacity takes the form of additional natural gas and renewable energy capacity (bottom panel of Figure 5), the magnitude of which typically grows over time. This temporal trend in electrification-driven capacity growth reflects multiple underlying factors. First, the rate of electric end-use technology adoption (and, in turn, demand for electricity) increases over time as sales shares grow, accounting for the turnover of the existing end-use equipment stock (see Mai et al. 2018). Second, the increased adoption and penetration of technologies with lower capacity credits—and related additions in flexible technologies (e.g., natural gas combustion turbines [NG-CTs] and energy storage)—lead to larger incremental increases in absolute installed capacity over time. Third, aging infrastructure and clustering in historical deployment lead to more lifetime-based capacity retirements of all generator types after 2030. However, the nuclear capacity results in particular do not capture any dynamic interaction between electrification and the economic retirement of nuclear plants, as the version of ReEDS used in this analysis assumes only lifetime-based nuclear retirements (Table 2).[22]

[22] Lifetimes for existing generators could be impacted by electrification, especially if changing and increasing load growth leads to higher wholesale electricity prices over an extended period of the day. This analysis does not explicitly evaluate this dynamic, but the impact of extended lifetimes for coal and nuclear generators on the electrification-driven evolution of the bulk power system is explored in Section 4.

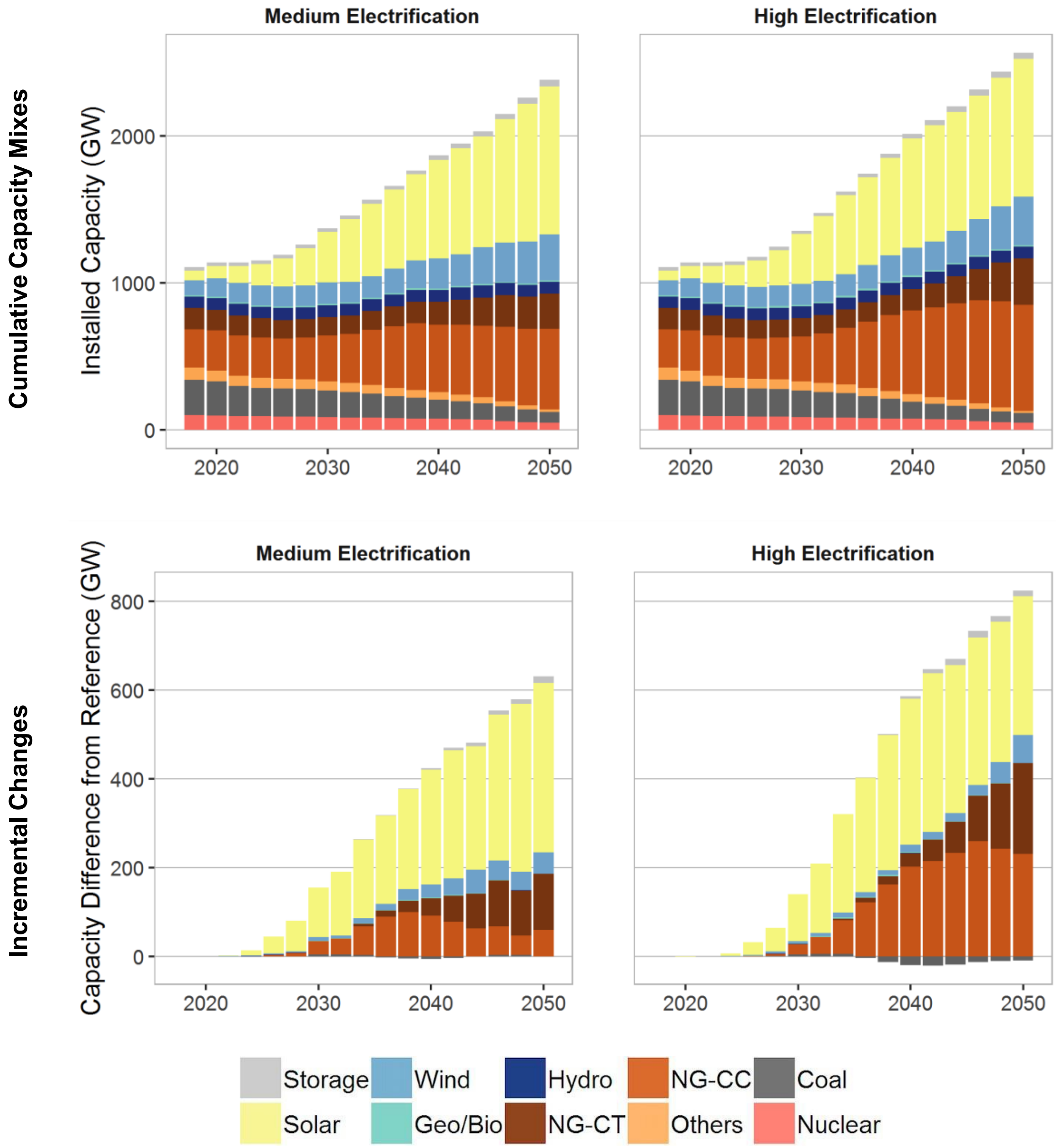

Figure 5. Cumulative installed capacities for the Medium and High electrification scenarios (top) and corresponding incremental changes, relative to Reference electrification (bottom)

Results from this figure were also presented in Murphy et al. (2020).

It is helpful to put these forward-looking scenarios of electric system evolution into the context of historical transitions on the electric system, which have occurred due to changes in electricity demand, generation technology advancements, fuel prices, expectations by the utility industry, and federal and local policies. In particular, the left panel in Figure 6 shows that historical annual additions of utility-scale generation capacity in the contiguous United States ranged from 3 GW to 59 GW per year, with an average value of 18 GW per year (from 1950 to 2018). Translating these annual additions into compound annual growth rates (CAGRs) reveals a range of 1% to 15%, or an average value of 5.1% (based on a 10-year rolling average).

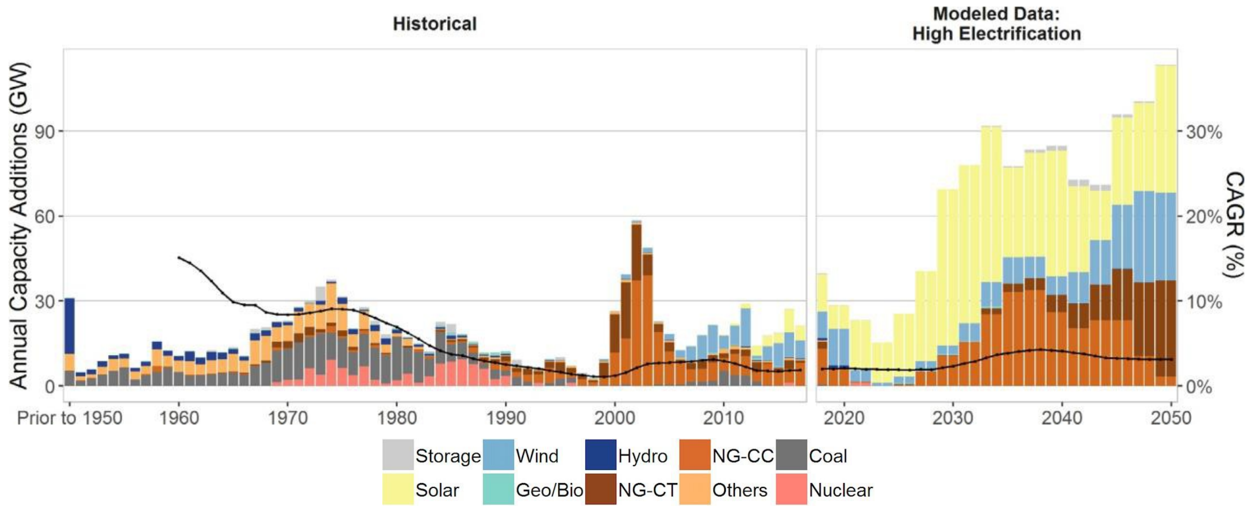

Figure 6. Historical and modeled annual capacity additions by technology (1950–2050)

Historical data are from EIA form EIA-860M (Monthly Update to Annual Electric Generator Report; EIA 2018b), while model results reflect the Base Case scenario with High electrification. The black solid line shows a 10-year compound annual growth rate (CAGR), based on cumulative capacity additions.

The Others category includes natural gas steam turbine, natural gas internal combustion engine, petroleum liquids, other gases, cokes, and all other entries in EIA form EIA-860M (Monthly Update to Annual Electric Generator Report; EIA 2018b).

NG-CT = natural gas combustion turbine, and NG-CC = natural gas combined cycle technologies.

The right panel of Figure 6 presents the timing and pace of capacity deployment under the Base Case scenario with High electrification. Considering gross capacity additions, the black line in Figure 6 indicates a future CAGR that is in line with the historical, long-term average for the U.S. power system. Modeled deployment rates for NG-CC technologies are similarly consistent with (or below) recent observations, with future NG-CC capacity additions peaking at around 30–40 GW per year in the 2030s. For NG-CTs, new annual installations grow slowly throughout the analysis period, eventually reaching just over 30 GW in the 2040s, concurrent with or following the widespread deployment of PV and wind technologies. Wind capacity additions[23] grow to 20–30 GW per year in the 2040s, or roughly double recent peak deployment years. Annual deployment rates for PV are sustained at 30–40 GW—which is well above recent observations in the contiguous United States—beginning in the 2020s and extending throughout the analysis period (Figure 6).[24]

[23] While offshore wind is an available technology in ReEDS, all wind capacity additions in this analysis take the form of land-based wind.

[24] Growth in solar outpacing growth in wind reflects two factors. First, more-rapid LCOE reductions are assumed for PV (NREL 2018, Section 3). Second, the native load profiles increase by 37%, 52%, 51% and 26% in the morning, afternoon, evening, and overnight hours (respectively) between the Reference and High electrification levels. This result primarily reflects the assumption that electric vehicle charging demand peaks in the late afternoon, which could result in better alignment of solar production and electricity demand under increasing electrification. Finally, it is difficult to assess the feasibility of this modeled pace of growth in wind and solar capacity. On the one hand, solar PV and land-based wind technologies are more modular in nature and use mass-produced products, which indicates

Electrification could also present enhanced opportunities for the economic deployment of a wider range of technologies—and especially those that facilitate a flexible electric system—even if the magnitude of impact is not prominently shown by Figure 6. High electrification drives up to 12 GW of new concentrating solar power (CSP) capacity by 2050, whereas no new CSP capacity is brought online under Reference electrification. In addition, increasing levels of electrification result in a near-term acceleration in the development of low-cost geothermal and hydropower resources during the 2020s; as a result, the High electrification scenarios involve up to an additional 2.6 GW and 1.1 GW (respectively) of installed capacity during the 2020s (beyond that observed under Reference electrification). Finally, the ReEDS model includes multiple energy storage technologies—including pumped storage hydropower, compressed air energy storage, and battery energy storage—which have a combined installed capacity of 23 GW in 2018. Under High electrification, these technologies experience sizable deployment during the 2030s and 2040s (Figure 6), which results in a more-than-doubling of storage capacity by 2050.[25]

The effects of electrification on transmission expansion are also captured in the ReEDS model, which evaluates transmission at two levels: long distance transmission and spur lines. Long-distance transmission capacity is built to facilitate the flow of energy—and the sharing of resources more generally—between balancing areas. The long-distance transmission network is tracked in terms of both capacity (GW) and length (GW-miles) within the model, and transmission expansion is co-optimized with generation expansion.

Despite the rapid and sustained deployment of generation capacity described above, widespread electrification does not require a large amount of additional long-distance transmission capacity under Base Case assumptions. In particular, the Base Case scenario with Reference electrification includes 9,900 GW-miles of new long-distance transmission capacity by 2050, which corresponds to an 11% increase over existing long-distance infrastructure (the latter of which is shown by the yellow lines connecting balancing areas in Figure 7). A similar amount of new long-distance transmission capacity is also built under Medium and High electrification, which require between 11% and 14% increases in long-distance transmission capacity by 2050 (respectively), relative to 2018 levels. This result partially reflects that ReEDS identifies transmission expansion primarily on an economic basis and does not consider all the noneconomic factors associated with transmission project development.[26]

the potential for an accelerated scale-up relative to more site-specific generator types. Other countries have also demonstrated deployment rates for PV and wind technologies in recent years that exceed all of the modeled deployment rates in the Base Case scenario with High electrification (China Statistics Press, n.d.). On the other hand, a rapid scale-up of PV and land-based wind technologies could introduce new challenges related to materials availability, development of their respective supply chains, and siting and land-use.

[25] For comparison, energy storage capacity is largely stagnant under Reference electrification (Figure 4).

[26] Assumed transmission costs vary significantly between regions, which reflects some of the siting, terrain, and other challenges (Cohen et al. 2019).

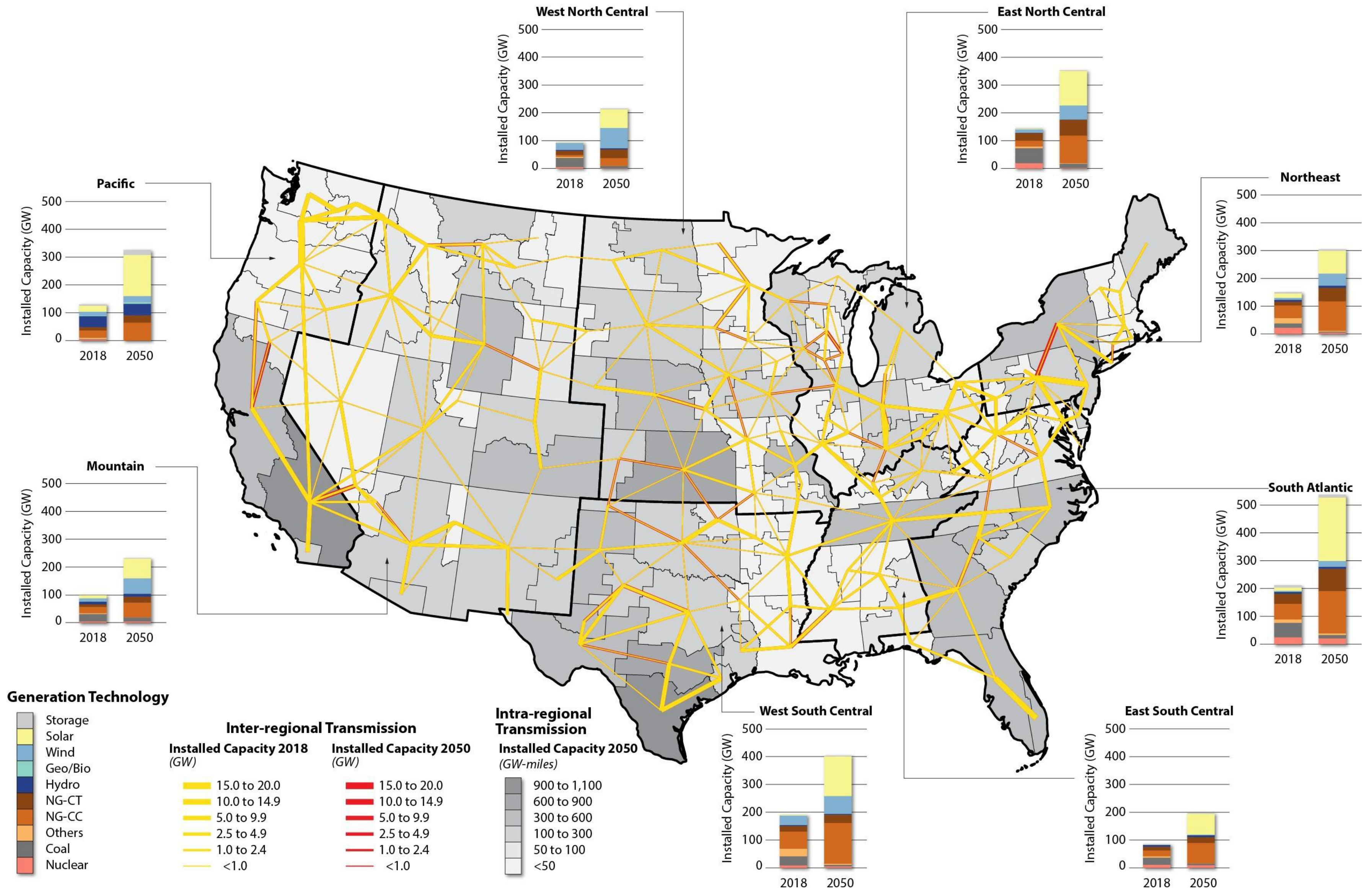

Figure 7. Capacity mix (by census region) and transmission capacity (by balancing area) for the Base Case with High electrification

Solid lines between balancing areas depict inter-regional, long-distance transmission capacity, while shading within a given balancing area depicts intra-regional, spur-line transmission capacity that is added after 2018. The 2018 long-distance transmission capacity network is shown as yellow lines. All 2018 values represent ReEDS model results for the Base Case scenarios.

Given the similar magnitudes of long-distance transmission additions across all levels of electrification, the red lines in Figure 7 are a reasonable proxy for the magnitude of transmission capacity growth over time across all Base Case scenarios. The geographic distribution of the solid red lines in Figure 7 is also similar to that observed under Medium electrification, but it represents a meaningful shift from the Reference electrification result (not shown). In particular, the growing load under increasing electrification improves the cost-effectiveness of local or nearby resources, due to the lower combined costs of closer generation sources and shorter transmission segments. Therefore, the long-distance transmission results in Figure 7 represent shorter and higher-capacity segments than are observed under Reference electrification.

The second level of transmission that is represented in ReEDS is intra-regional spur lines, which are built within a given model balancing area to connect new wind and solar generators to the existing transmission network. These transmission line segments are generally shorter than inter-regional lines, but their cumulative growth (in units of GW-miles) depends on the number and capacity of new spur lines.[27] For the Base Case scenario with High electrification, this model result is illustrated by the shading in Figure 7, which depicts the amount of additional spur line capacity development between 2018 and 2050.

The magnitude of new spur-line capacity scales with the level of electrification, which reflects the electrification-driven deployment of new wind and solar installations. In turn, spur lines account for the majority of incremental transmission capacity additions by 2050 under High electrification.[28] *Total* new transmission capacity (including long-distance and spur-line transmission) also scales with the level of electrification, with 18%–21% increases under Reference electrification, 24%–31% increases under Medium electrification, and 27%–35% increases under High electrification by 2050 (relative to 2018 levels), where the ranges reflect assumptions about end-use technology advancement.

2.1.2 Electricity Generation and Asset Utilization

The effects of electrification on the annual generation mix (top panels of Figure 8) largely follow from the previously described changes in the capacity mix. Electrification-driven growth in generation begins in the mid-2020s and increases over time; by 2050, Medium and High electrification require 1,200 terawatt-hours (TWh) and 2,000 TWh of additional generation, respectively, beyond that required under Reference electrification. Similar to the capacity results in the previous section, this electrification-driven growth (bottom panels of Figure 8, page 20) primarily takes the form of additional generation from NG-CC, wind, and solar technologies.[29]

We also estimate the impact of electrification on the utilization patterns of the various generator types (Table 6, page 21). For coal-fired generation, the most impactful effects are the electrification-driven reductions in natural gas prices and increases in the penetration of

[27] Spur line length is calculated through the supply curve calculation for each technology, which is based on a geospatial optimization model that sorts the developable sites by cost, based on the resource quality and accessibility to the transmission network. Details of the calculation method can be found in Appendix B.2 of Murphy et al. (2019).
[28] This result is demonstrated in Figure 7, where the aggregate deployment associated with the shading (in GW-miles) exceeds the new long-distance transmission capacity (red) multiplied by the line lengths.
[29] Generation from energy storage is not shown in Figure 8 because the round-trip efficiencies are less than one.

renewable energy technologies, the combination of which outweighs the effects of increases in electricity consumption. As a result, increasing levels of electrification result in slight incremental reductions in coal-fired generation during the 2030s and early 2040s (bottom panel of Figure 8), beyond those observed under Reference electrification (Figure 4). Within the context of retirements over time, electrification-driven changes in coal-fired capacity and generation result in increased capacity factors for the coal-fired power plants that remain on the system into the 2040s (Table 6).

Similarly, the capacity factors of NG-CC systems grow with increasing electrification (i.e., comparison across rows in Table 6), which indicates that the electrification-driven increase in natural gas-fired generation (bottom panels of Figure 8) outpaces the related increase in NG-CC capacity (Figure 5). By contrast, generation from and utilization of nuclear power plants are largely insensitive to electrification level. This null result partly reflects the exogenous lifetime-based retirement assumptions in ReEDS, which reduce nuclear generation over time (Figure 8). However, nuclear capacity *factors*—which represent a ReEDS output—remain unchanged both over time and across electrification levels (Table 6).

Exploring electrification's impacts on the utilization of renewable energy technologies requires an expanded set of metrics. For example, the penetration of variable renewable energy (VRE) is a useful metric for understanding whether electrification could influence the share of total generation that is sourced from VREs. The results in Figure 8 reveal that increasing electrification drives additional VRE generation, but the incremental increase in VRE generation roughly scales with the incremental increase in *total* generation. Therefore, while VRE penetration increases prominently over time, it is largely insensitive to electrification level (Table 6). Note that this relatively constant level of VRE penetration does not reflect an effective "limit" on either the system or the available renewable energy resources (see Section 5), but rather the complex interactions among technology costs, fuel costs, and load.

Within the context of these VRE generation and penetration results, electrification could also impact the magnitude and rate of renewable energy curtailments.[30] Under Base Case assumptions, curtailments are fairly insensitive to the assumed level of electrification: despite growth over time, annual curtailment (rates)[31] remain below 117 TWh (4%) through 2050 across all levels of electrification (Table 6). The relative insensitivity of curtailments across electrification levels primarily reflects the electrification-driven increase in the deployment of flexible natural gas-fired generators and energy storage technologies. Changes in the timing and magnitude of electricity demand (and related increases in flexible loads) also help mitigate curtailments, but the relative influence of this effect is more muted.

[30] Renewable energy technologies are often dispatched first because of their low or zero marginal costs. As a result, when abundant renewable energy is available during periods of low demand—coupled with system inflexibilities driven by minimum generation requirements and transmission congestion—curtailment of VREs could occur. Note that results presented here reflect *average* curtailments; *marginal* curtailment rates are typically larger.
[31] Curtailment rates are defined here as average annual VRE curtailment divided by annual VRE generation.

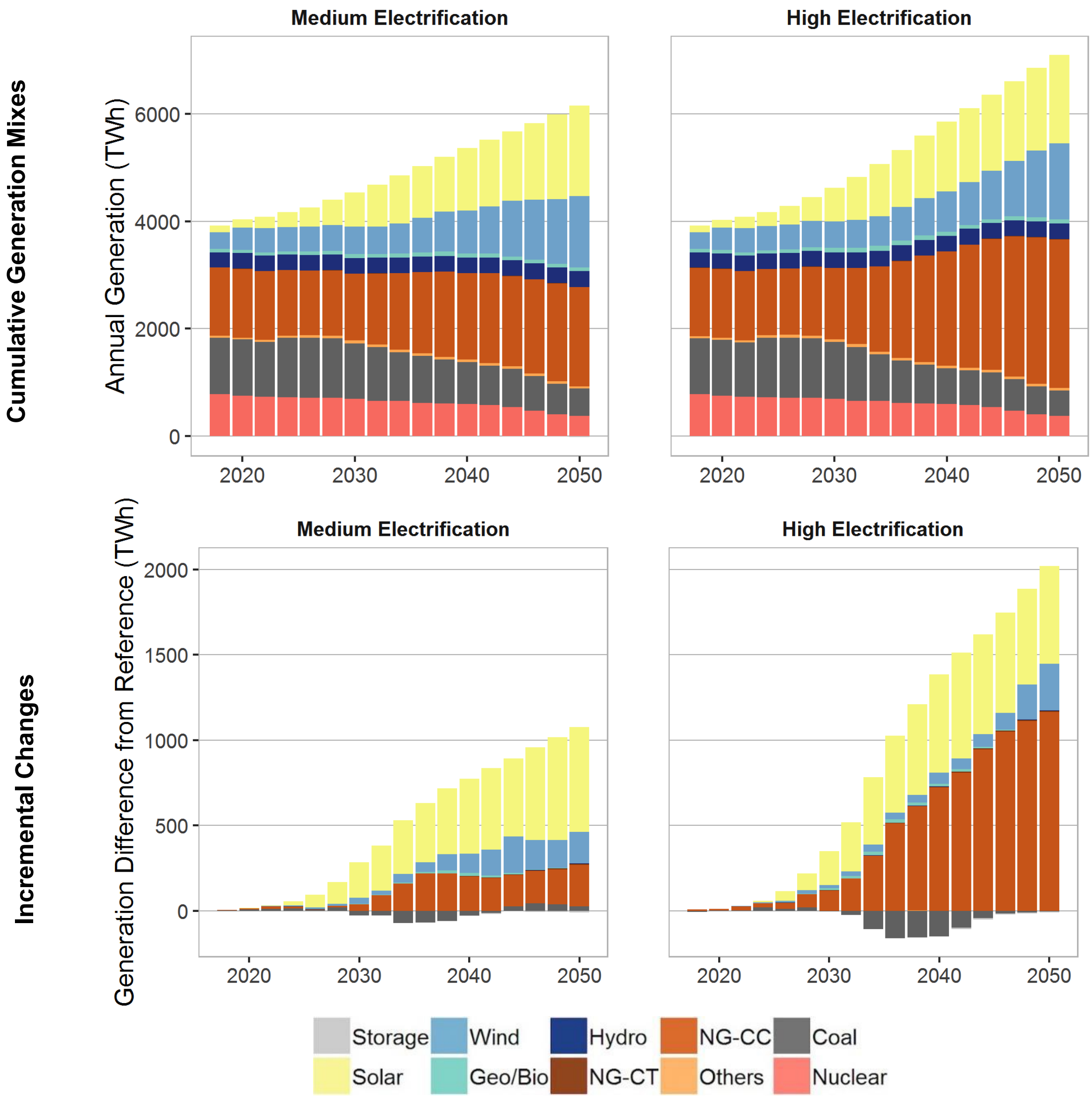

Figure 8. Cumulative and incremental changes to the generation mix under Medium and High electrification

Results from this figure were also presented in Murphy et al. (2020).

Table 6. Effects of Electrification on Select Utilization Metrics: Moderate End-Use Technology

	2018[a]	2050 Reference Electrification	2050 Medium Electrification	2050 High Electrification
Coal-fired power plant capacity factors (%)[b,c]	50	73	77	83
Nuclear power plant capacity factors (%)[b]	90	90	90	90
NG-CC capacity factors (%)[b]	55	37	38	44
Variable renewable energy penetration (%)[b]	11	44	49	43
Curtailment rates (%)[b]	1.5	2.7	3.9	1.8
Transmission Flows (TWh)[d]	1,360	2,150	2,240	2,210

[a] 2018 values in the table reflect ReEDS model results for the Base Case scenario with Reference electrification and Moderate end-use technology advancement, not observed values.

[b] Very little variation is observed in these utilization metrics across the end-use technology advancement levels, so results are shown for the Moderate level only.

[c] Increases in coal-fired power plant capacity factors over time primarily reflect the increased utilization of the plants that remain on the system, accounting for retirements over time. Incremental increases in 2050 due to electrification reflect a combination of changes in installed capacity (Figure 5) and generation (Figure 8).

[d] Flow along the inter-regional transmission network varies across end-use technology advancement levels, with values ranging from 1,920 TWh to 2,150 TWh under Refence electrification; 2,010–2,240 TWh under Medium electrification; and 2,140–2,350 TWh under High electrification.

Finally, High electrification is also found to increase flows along the long-distance transmission network, particularly toward the end of the analysis period (Table 6). This increase in flow occurs in spite of the similar level of transmission capacity across electrification levels, which indicates that the long-distance transmission network is being used more efficiently under High electrification. However, the electrification-driven growth in the transmission flows (3%–13% in 2050 under High electrification)[32] is lower than would be suggested based on the incremental load growth alone (~40%). The discrepancy between these two metrics reflects both the increase in transmission flow over time under Reference electrification, as well as the higher value associated with adopting more local resources to meet demand under High electrification.[33]

2.2 Cost Metrics

Building on the results presented in Section 2.1, we also assess the costs associated with future capacity and generation expenditures across varying electrification and end-use technology advancement levels. Note that the results in this section are *not* designed to convey how various stakeholders—including consumers, producers, and distributors for different regions—could be

[32] The greater transmission flows under High electrification also lead to greater transmission *losses,* but these losses are estimated to be about 1% of total generation. ReEDS also assumes 5.3% losses on the distribution system. Additional research is needed to understand the impacts of electrification on the distribution system (see Text Box 2), including impacts on distribution system losses.

[33] ReEDS models (1) "contracts" between regions for meet peak planning reserve requirements and (2) how electrification changes the amount of contracted capacity, which is one measure of resource sharing.

economically impacted by electrification; this is an important topic, but it is beyond the scope of this analysis because it requires a level of granularity that exceeds the present results.

To explore the cost implications of electrification, we first present the net present value of bulk electric system costs from 2019 to 2050 (in real 2016 dollars); this result is derived from ReEDS model and includes expenditures for all new generation, transmission, and storage capacity, as well as fuel and other operating costs associated with electricity supply and modeled grid services (Section 2.2.1). Modeled bulk electricity prices are also reported, to show how these electric system costs change over time. Finally, to provide a more complete picture of electrification's effect on *energy* system costs, we weigh these electric sector system cost results against the related *demand*-sector system costs, which follow from the technology adoption and energy consumption results presented by Mai et al. (2018) (Section 2.2.2).

2.2.1 Bulk Electric System Costs

Figure 9 shows the net present value of bulk electric system costs, which comprise expenditures related to transmission-level assets (from 2019 to 2050) across all electrification and end-use technology advancement scenarios. Larger loads intuitively drive an increase in bulk electric system costs, which primarily take the form of additional fuel and capital costs, but the magnitude of this increase depends strongly on end-use technology advancement (black vertical lines in Figure 9). Considering both of these factors together, total bulk electric system costs are incrementally increased by 12%–17% under Medium electrification and by 21%–29% under High electrification, the latter of which corresponds to system costs that are approximately $600–$900 billion higher than under Reference electrification (Figure 9).[34]

Though absolute bulk electric system costs intuitively grow with increasing levels of electrification, how this cost changes on a per incremental unit of electricity basis can reveal how challenging it is to meet incremental demand growth from electrification. To do this, we calculate the levelized cost of meeting the next increment of electricity demand for the Medium and High electrification scenarios (relative to Reference electrification). Specifically, we divide the incremental system cost (Figure 10, right panel) by the present value of incremental electricity consumption.[35] The results of this calculation reveal levelized costs for meeting an incremental increase in electricity consumption of $40–$46/MWh under both Medium and High electrification; this similar result indicates there are abundant resources in the United States with similar costs to meet potential electrification-driven growth in demand for electricity.

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[34] This result is based on the present value of total bulk electric system costs from 2019 to 2050 and a 3% real discount rate, which is consistent with that used by the EIA to estimate long-term costs and benefits. For comparison, applying a 7% discount rate yields incremental bulk electric system costs that range from 11% to 15% under Medium electrification, and from 16% to 24% under High electrification. Note that a higher discount rate (5.3% real, WACC) is used in most cases for the ReEDS investment and dispatch decision-making.
[35] This discounting (with a 3% rate) allows us to quantify a *levelized* value rather than a simple normalization.

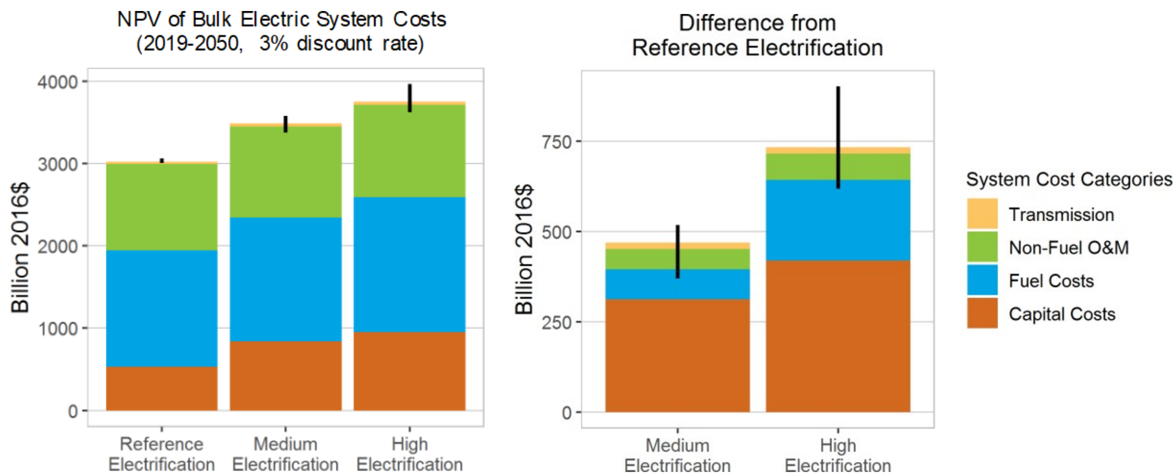

Figure 9. Net present value of bulk electric system costs from 2019 to 2050 (in 2016$) across different electrification and end-use technology advancement levels

Stacked bars reflect Base Case assumptions that have been applied to varying levels of electrification, and the ranges denoted by black lines at the top of each stacked bar reflect different end-use technology advancement levels.

Cumulative results are shown in the left panel, and incremental results (relative to the corresponding Reference electrification scenario) are shown in the right panel.

O&M = operation and maintenance

A related result lies in the potential effects of electrification on national-average electricity prices. The ReEDS model simulates a bulk electricity price, which is based on the marginal costs of meeting load (the "energy price"), capacity requirements (the "capacity price"), and other requirements (e.g., operating reserves and state policy requirements).[36] This bulk electricity price metric reflects the cost of meeting an incremental unit of electricity, but it also considers all modeled reliability-related grid services (e.g., resource adequacy requirements and operating reserves)[37] as well as state policy mandates. The resulting bulk electricity price is similar to "wholesale" prices in real restructured markets,[38] and it provides a measure of how bulk electric system costs change over time. Finally, because it is a *marginal* measure, it can inform the slope of the "supply curve" for meeting new electricity demands from electrification.

Based on these marginal costs, we find that the bulk electricity price increases at a similar rate over time across all Base Case scenarios (Figure 10). Bulk electricity prices under High electrification vary by less than 15% from those observed under Reference electrification—in spite of a 40% increase in generation relative to the Reference scenario, and an approximate doubling of installed capacity between 2018 and 2050 under High electrification. However, these results only include costs for the bulk electric system, and they do not include potential costs on the distribution system (Text Box 1), which are approximated in Section 2.2.2.

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[36] Values reported here are annual and national averages in 2016$, weighted by the number of hours in each time-slice and the load in each model balancing area.
[37] Note that ReEDS does not capture all aspects of reliability.
[38] Despite their similarity to locational marginal prices, the bulk electricity prices presented here include the fixed costs (whereas locational marginal prices, in principle, include variable operating costs only).

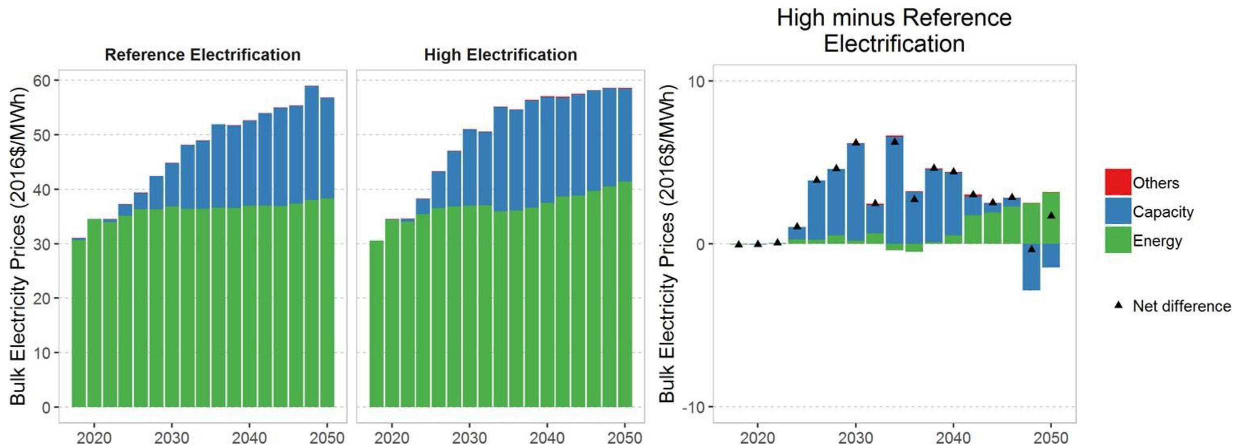

Figure 10. National-average bulk electricity prices under Reference electrification (left) and High electrification (middle), and their difference (right)

The model results shown here are more closely related to wholesale electricity prices than retail electricity prices, but they differ in significant ways from locational marginal prices in restructured markets. The legend indicates the range of cost categories that reflect the marginal prices of meeting different constraints in the model; the Others category includes operating reserve and state policy requirements.

Additional insights lie in how the individual components of this simulated bulk electricity price vary across electrification levels. For example, the marginal cost of meeting capacity requirements (blue bars in Figure 10, page 24) rises earlier and faster under High electrification (right panel), which could have near-term profitability implications for generators that receive a substantial share of their revenue from providing capacity services. However, by the end of the analysis period, marginal capacity prices under High electrification are actually slightly lower than under Reference electrification, which partially offsets modest increases in the marginal cost of meeting load (green bars in Figure 10, page 24).

Text Box 1. Impacts of Electrification on the Distribution System

Widespread electrification would likely have far-reaching effects throughout the U.S. electricity system, including effects on utility-scale generation, the transmission network, and the electric distribution system. All these components of the electricity system are interrelated, and exploring the dynamic interactions among them is a complex task, even for analyses of the current system. The complexity is increased when layering on electrification, which would impact each component in different ways, as well as the interactions among them.

This study is beginning to explore the potential impacts of electrification on the U.S. electricity systems by performing detailed analysis of bulk electric system evolution. There are many unanswered questions about how this system could evolve under different scenarios of widespread electrification, some of which we explore in this report. However, it is also important to note that similar scenarios would likely introduce new challenges and opportunities within the electric distribution system, which are not explored in detail here. Gaining a more holistic understanding of the potential impacts of electrification—including the potential benefits and barriers associated with electrification-enabled demand-side flexibility—will require more-detailed modeling and analysis of the distribution system's unique characteristics and properties.

Widespread electrification, intelligence of building loads, and deployment of electric vehicle charging—a key piece of electrification—can all support increased flexibility in the future power system, but they can also introduce challenges. DC fast charging stations, for example, can require more than 50 kilowatts of power per vehicle and up to several megawatts per charging station, which is roughly equivalent to adding the peak load of several thousand homes at a single point on the distribution grid. Prior analysis has identified potential issues with steady-state voltage violations, equipment overloading, and in some cases, power quality and transient voltage stability with deployment of electric vehicle charging stations (Nour et al. 2018; Bass and Zimmerman 2013; Marah et al. 2016; Mehmedalic, Rasmussen, and Harbo 2013; Wamburu et al. 2018). Even the spatial clustering of residential electric vehicle (EV) charging could introduce challenges for distribution systems (Muratori 2018), such as the potential need to upgrade distribute system infrastructure. The level at which distribution system impacts could emerge depends significantly on the characteristics of the system in question, where EV charging occurs, and which type of EV chargers are employed.

Related to these previous observations, there are many research questions that require future work:

- To what extent could the effects of electric vehicle charging and increased electric building load be offset by the deployment of distributed energy resources (DERs), smart controls, and upgrades of utility grid equipment?
- Can co-deployment of DERs and electric vehicle charging stations help mitigate potential challenges and, in turn, increase the hosting capacity of each (e.g., Weckx and Driesen 2015; Zhang et al. 2018)?
- What are the trade-offs between bulk power and distribution system needs when it comes to load "reshaping"?
- What business models, rate designs, and communication advancements would facilitate increased access to flexible loads? (Muratori, Schuelke-Leech, and Rizzoni 2014; Engel et al. n.d.)

2.2.2 Energy System Costs

This section considers the net effects of electrification on both electric system costs and other demand-side system costs associated with building and operating the whole U.S. energy system. To arrive at this result, we combine the detailed bulk electric system costs from ReEDS (Section 2.2.1) with EnergyPATHWAYS results for electricity distribution and demand-sector system costs, the latter of which are a function of both electric end-use technology adoption (electrification) and advancement.[39] Demand-sector expenditures for energy-related fuel and operating costs are tracked directly in EnergyPATHWAYS, along with *incremental* capital expenditures relative to the Reference electrification level. Table 7 defines the boundaries of this energy system cost calculation, and Appendix C provides details about the calculation itself.

Based on the results of this calculation, we estimate that the net present value of energy system costs under the Base Case scenario with Reference electrification is on the order of $28 trillion,[40] which demonstrates the extent of economy-wide expenditures that are related to energy supply and consumption. This estimate provides helpful context for the incremental system cost effects of electrification, which are shown in Figure 11.

Considering first the results for Medium electrification, we find that the incremental energy system cost effects (black triangles in Figure 11) range from -$1,200 billion (savings) to near zero. This range of results represents system cost effects that are systematically lower than what would be implied by considering the electric system cost impacts (blue- and teal-shaded bars) in isolation. Moreover, it indicates that electrifying select sub-sectors (with potentially lower barriers to electrification; Section 1.2) has the potential to generate energy system cost *savings* that could be realized by a variety of stakeholders.[41] Sources of energy system cost savings lie exclusively in the demand sectors and take the form of avoided direct fuel-use and the reduced operation and maintenance (O&M) costs associated with electric end-use technologies (relative to conventional technologies). These system cost savings are found to be sufficient for offsetting incremental increases in the electric sector and in demand-sector equipment capital under Medium electrification.[42]

Under High electrification, the directionality of electrification's effect on energy system costs depends strongly on assumptions about the cost and performance of electric end-use technologies that influence both electric sector costs (due to the amount of electricity required to satisfy service demands; Section 2.2.1) and demand-sector costs (due to the capital and operational costs associated with the electric end-use technologies). For example, when assuming a Rapid advancement in end-use electric technologies, High electrification provides net energy system cost savings that are similar in magnitude to the corresponding Medium electrification result. Under Moderate end-use technology advancement, the energy system cost impacts of High electrification are still smaller than the electric system cost impacts in isolation, but the net effect is a modest incremental increase in energy system costs. Finally, under Slow end-use technology advancement, accounting for demand-sector system cost effects exacerbates the electrification-driven increase in electric sector system cost effects (Section 2.2.1 and Figure 11). This wide

[39] Electric end-use electric technology improvements over time impact energy system costs via changes to both equipment capital costs and energy consumption. End-use equipment costs could also influence technology adoption and costs to individual consumers, but we do not consider or calculate these effects in our analysis.
[40] This estimate reflects absolute values for system costs from across the electric sector, but the EnergyPATHWAYS model only tracks incremental changes in the costs associated with equipment capital in demand sectors. Therefore, this is likely an underestimate of the level of expenditure from across the energy sector.
[41] As noted elsewhere, we do not assess how costs and savings are distributed; some stakeholders could experience economic losses even as there may be net cost savings for the entire energy sector.
[42] Incremental demand-sector equipment capital costs reflect differences in capital expenditures for end-use electric equipment (EVs, EVSEs, heat pumps, etc.) compared to conventional alternatives.

range of results for a fixed level of electric end-use technology adoption demonstrates the influence of technology research and development efforts related to capital costs and efficiency.

Table 7. Scope and Source of Results for Energy System Cost Calculation

	Category in Figure 11	System Cost Category	Source of Results
Electric Sector	Generation and Storage Capital	Generation capital costs	ReEDS
		Storage capital costs	ReEDS
	Fuel Consumption and O&M	Fuel consumption costs	ReEDS
		Non-Fuel O&M costs	ReEDS
	Transmission and Distribution	Transmission investment costs	ReEDS
		Distribution system costs[a]	EnergyPATHWAYS
Demand Sectors	Fuel Infrastructure	Infrastructure and delivery costs outside the electric sector[b]	EnergyPATHWAYS
	Fuel Consumption and O&M	Fuel consumption costs in all demand-side sectors[c]	EnergyPATHWAYS
		O&M costs for end-use equipment	EnergyPATHWAYS
	Equipment Capital	Incremental capital costs[d] for end-use equipment	EnergyPATHWAYS

[a] This category reflects a distribution revenue requirement, which represents the money a utility must collect through rates each year to pay all costs associated with the distribution system. It includes ongoing expenses and debt-service on past investments. In EnergyPATHWAYS, these costs are calculated using tariff numbers from the National Energy Modeling System (NEMS) and are scaled with the simultaneous peak load on distribution feeders. This calculation does not consider revenue requirements for transmission. Because the calculation is performed in EnergyPATHWAYS, it does not reflect the ultimate load shapes in ReEDS, which differ due to different demand-side flexibility assumptions and methodologies.

[b] The largest component that differs between scenarios is the annual revenue requirement associated with natural gas transmission and distribution pipelines. These cost estimates are based on historical revenue requirements pegged to total gas throughput on each part of the system. Pipelines are depreciated over their assumed physical lifetime and are paid for even if utilization drops. The portion of gas transmission pipelines allocated to electricity generation is subtracted from the overall calculation because these costs are assumed to be embedded in the delivered fuel prices for electricity generation in ReEDS, which are captured under the Electric Sector: Fuel Consumption and O&M category.

[c] This represents fuel costs for all non-electric final energy demand, where petroleum products and natural gas are the largest components. Natural gas fuel costs are scaled based on the delivered natural gas price to the electric sector (modeled in ReEDS), to reflect price elasticity. Detailed calculation methods are in Appendix C and described by Sun et al. (2020).

[d] This category considers the incremental demand-side equipment capital costs under Medium and High electrification, relative to Reference electrification level. For instance, the incremental cost of a heat-pump hot water heater over a gas water heater represents the portion of the demand-side capital cost that resulted from electrification, and it can be compared with the resulting changes in other system costs. Note that *total* demand capital costs would represent the sum of all business and consumer purchases of equipment that use energy, but these are not conventionally thought of as an energy system cost.

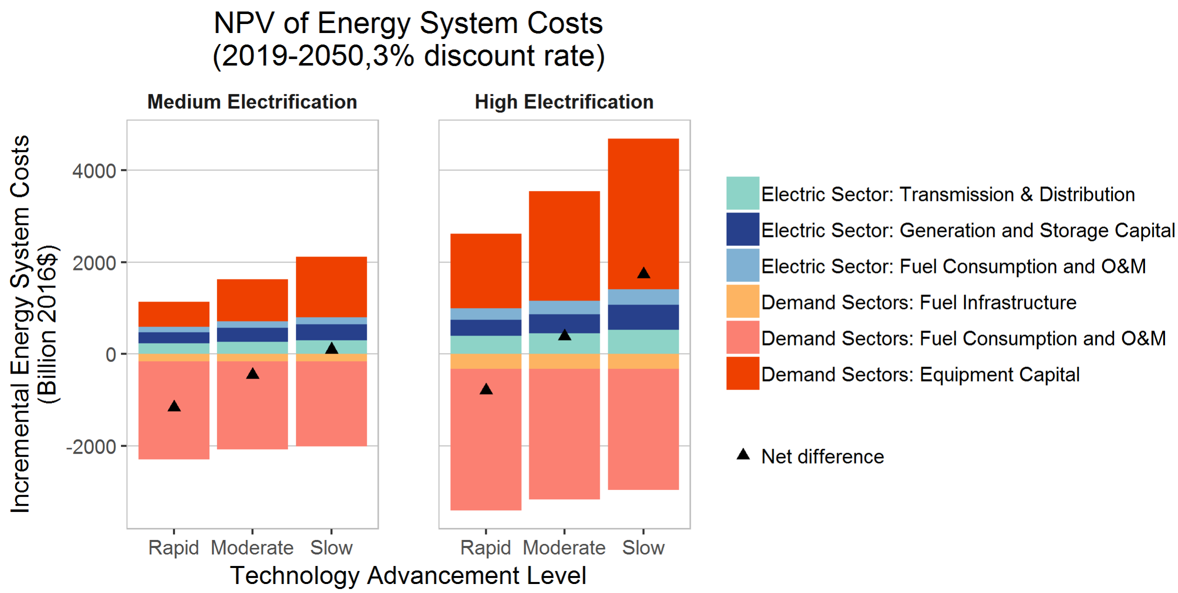

Figure 11. Net present value of incremental energy system costs relative to Reference electrification

Changes in the height of the Demand Sectors: Fuel Consumption and O&M bars across electric end-use technology advancement levels reflect a combination of changes in electric end-use equipment O&M costs and the delivered price of natural gas, the latter of which is dictated by power sector consumption of natural gas in this analysis.

To summarize, the energy system cost analysis in this section shows that technology improvements could reduce, or possibly eliminate the direct incremental energy system costs associated with increasing levels of electrification. Conversely, it shows that absent these improvements, widespread electrification in all end-use sectors could increase the present value of total system costs across the entire energy sector. Sections 3 and 4 explore other demand-side and supply-side factors that could influence overall power and energy system costs.

2.3 Energy Consumption

This section explores electrification's net influence on energy consumption for the Base Case scenarios, weighing the reduction in demand for fuels that are displaced by electricity against a possible increase in fuel consumption associated with electricity generation. Natural gas consumption is presented first, because it is used in significant shares across multiple sectors; as a result, electrification could result in not only changes in the absolute consumption of natural gas but also shifts in its sectoral distribution. In Section 2.3.2, we present estimates of final and primary energy consumption by sector and fuel type, accounting for both the electric and end-use sectors. Final energy refers to the amount of energy at the point of consumption that is then converted to end-use services,[43] whereas primary energy encompasses final energy as well as

[43] Final energy consumption includes the energy embedded in liquid fuels used for transportation, as well as the energy embedded in electricity and natural gas delivered to homes; but it does not include the conversion by home appliances to services such as cooking or heating. For example, for space heating, final energy consumption covers the energy that is needed to operate the heater but not the thermal energy produced by the heater.

energy losses that occur during the conversion of fuels to electricity.[44] It is important to note that the models used in this analysis do not include a detailed representation of fuel extraction, transport, and distribution; however, they do apply a top-down approach that enables an accounting-based assessment of the impacts of electrification on overall energy and fuel demand.

2.3.1 Natural Gas Consumption

In the absence of other external drivers, the primary effect of electrification on natural gas consumption is a shift in where natural gas is consumed within the energy sector; however, electrification on its own may not have a major effect on the total amount of natural gas consumed under Base Case assumptions. This finding is demonstrated in Figure 12, which reveals a similar increase in energy-sector natural gas consumption over time under both Reference (31 quads) and High (33 quads) electrification.[45]

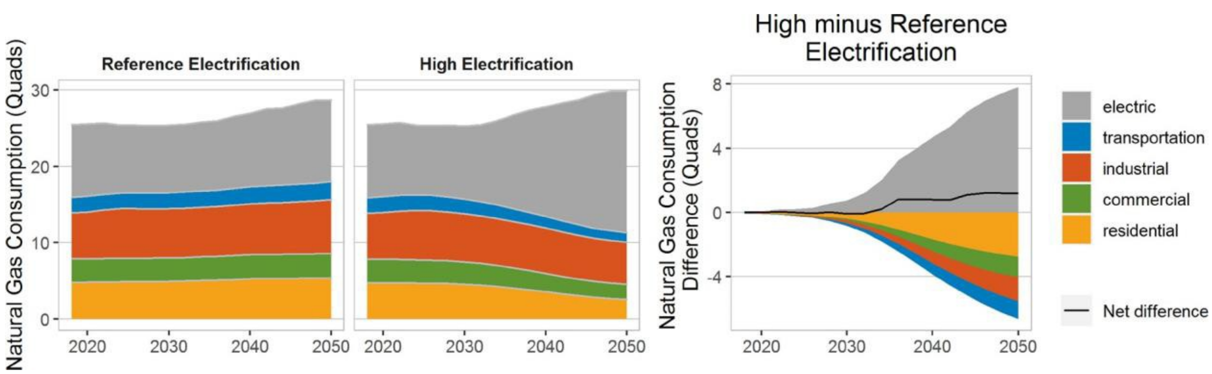

Figure 12. Natural gas consumption by sector for Base Case scenarios with Reference (left) and High electrification (middle), and the difference between the two scenarios (right)

End-use natural gas consumption data are from modeled results in Mai et al. (2018). Approximately half of the electrification-driven reductions in industrial natural gas consumption reflects reductions in refining outputs.

The relative insensitivity of energy sector-wide natural gas consumption to increasing levels of electrification reflects two competing effects: (1) reductions in end-use consumption of natural gas (including refining) as services are increasingly powered by electricity (Mai et al. 2018) and (2) increases in natural gas consumption for electricity generation to meet incremental loads.[46] Together, these two effects indicate a significant redistribution across the energy sector, such that the electric sector represents the majority (57%) of energy-sector natural gas demand by 2050 under High electrification (compared to 35% in 2018; Figure 12).

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[44] Calculating primary energy for thermal power plants is tied to the efficiencies of those power plants, but primary energy estimation methods for renewable energy are more complex. Here we adopt the EIA's "thermal-equivalent" method (EIA 2012, 2018c). See Appendix C for more details and discussion.

[45] Energy sector natural gas consumption in 2018 is 27 quads in Figure 12, whereas economy-wide natural gas consumption in 2018 was ~29 quads. Not all end uses are represented in the models employed in this analysis.

[46] Beyond the ultimate service demand requirements, determining the net impact of these two competing effects on natural gas consumption depends on many factors, including the relative efficiencies of utility-scale natural gas generation versus end-use natural gas technologies; the relative efficiencies of electric versus non-electric end-use technologies; price-rebound effects as less natural gas is used directly by many end users; and the displacement of end-use technologies that are powered by other fuel types.

Natural gas consumption trends are closely related to the price of natural gas through price-consumption elasticity effects (see Sun et al. 2020 for details of the ReEDS representation). Under Base Case assumptions, the delivered price of natural gas to the electric sector grows to slightly greater than $5/MMBtu in 2050 regardless of the electrification level, despite the fact that High electrification drives an approximate doubling in electric sector natural gas consumption (from 2018 to 2050; Figure 12). This result reflects the counteracting effects of reduced end-use natural gas consumption (downward pressure) and increased electric sector natural gas consumption (upward pressure) on prices. The sectoral shifts in natural gas consumption can affect the various stakeholders of the natural gas industry—such as producers, distributors, industry, and household natural gas customers—in different ways.

2.3.2 Final and Primary Energy Consumption

Figure 13 shows final and primary energy consumption estimates for 2018 and under the Base Case scenarios with Reference, Medium, and High electrification in 2050. The left panels of Figure 13 show that electrification drives a reduction in final energy consumption, due to the greater efficiencies associated with electric end-use technologies compared to their non-electric counterparts. For example, 2050 final energy consumption under High electrification is estimated to be 17 quads lower than the Reference scenario in the same year, and 11 quads lower than in 2018. The same panel shows that both electricity's share of final energy and the absolute amount of final energy delivered through electricity as an energy carrier increases with electrification. Under High electrification, electricity's share of final energy approximately doubles between 2018 and 2050.[47]

The bottom-left panel of Figure 13 shows final energy estimates by fuel type, which highlights how most of the electrification-driven reductions in final energy are sourced from avoided petroleum consumption. This result primarily reflects changes in the transportation sector, as the increased adoption of electric vehicles displaces internal combustion vehicles. When combined with more modest changes in natural gas (Section 2.3.1) and coal consumption, the aggregate result is an electrification-driven reduction in the amount and share of fossil fuel consumption, on a final energy basis. For example, the High electrification scenario results in 39 quads (62%) of fossil fuel final energy being consumed in 2050, compared with 61 quads (75%) under Reference electrification and 58 quads (79%) in 2018.

Similar trends are apparent in our model results for the effects of electrification on primary energy consumption. In 2018, primary energy consumption is estimated to be 98 quads, 37% of which is sourced from electricity (top panel) and 81% of which is sourced from fossil fuels (bottom panel). These values are similar to estimates for the Reference electrification scenario in 2050 (Figure 13),[48] but increasing electrification leads to (a) a reduction in total primary energy

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[47] These numerical values differ from those reported in Mai et al. (2018) due to minor adjustments in electricity demand and inclusion of energy demand from additional subsectors (refining, fossil fuel extraction, and combined heat and power).

[48] Under Reference electrification, primary energy consumption in 2050 is estimated to be 104 quads. Given the population and GDP growth that is assumed (implicitly consistent with the EIA's Annual Energy Outlook Reference case), this six-quad increase over the next 32 years indicates significant increases in energy efficiency.

consumption,[49] (b) an increase in electricity's share of primary energy, and (c) a reduction in the aggregate share of primary energy that is sourced from fossil fuels (Figure 13).

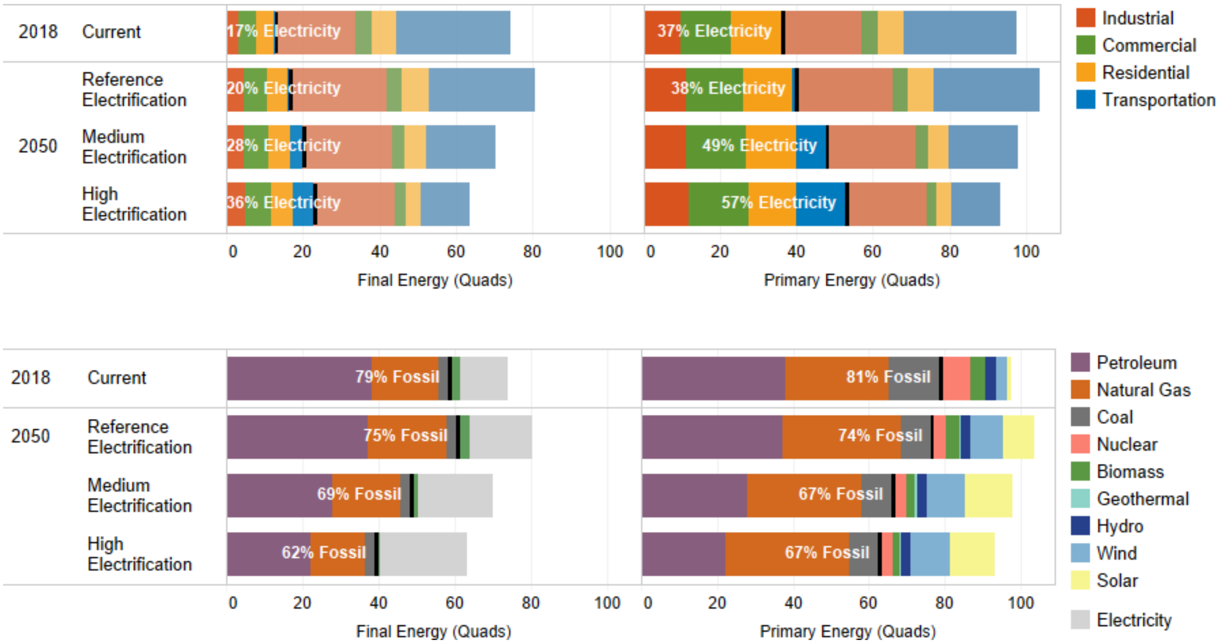

Figure 13. Final and Primary Energy Use in the Base Case electrification scenarios.

2018 estimates are based on our modeled results for the Base case scenario with Reference electrification, and they differ slightly from historical estimates (EIA 2019a). Here we estimate 98 quads of primary energy (compared to 100 quads in EIA 2019a), and 74 quads of final energy (compared to 75 quads in EIA 2019a). Primary energy estimates for renewable energy are calculated using the thermal-equivalent method (EIA 2012, 2018c).

A subset of the results from this figure were also presented in Murphy et al. (2020).

2.4 Air Emissions

This section explores the potential impacts of electrification on direct emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides (NO_x) from the electric and end-use sectors.[50] This defined scope does not capture the full range of environmental impacts associated with energy-sector air emissions; doing so would require the assessment of other types of emissions, non-combustion sources of emissions, and life-cycle air emissions.[51] Rather, our

[49] Primary energy consumption in 2050 in the High electrification scenario ranges from 91 quads with Rapid end-use electric technology advancements to 96 quads with Slow advancements.
[50] Energy sector CO_2, SO_2, and NOx air emissions are all the subject of state-level and federal regulations, which have helped drive declining emissions trajectories over time. Of the remaining sources for these air emissions, electricity generation was responsible for 75% of anthropogenic SO_2 emissions, the transportation sector was responsible for 55% of anthropogenic NOx emissions, and industry was responsible for a measurable amount of both SO_2 (20%) and NOx (18%) emissions in 2014 (EPA 2019). CO_2 emissions are more distributed across the energy economy, with the electric sector, transportation, and all remaining demand sectors (buildings and industry) each accounting for roughly one-third of energy CO_2 emissions in 2017 (EIA 2019b).
[51] Non-combustion sources that are beyond the scope of this analysis include CO_2 formed during certain chemical reactions (e.g., cement formation) and agricultural or land-use processes, SO_2 formed during metal smelting and

approach reflects the information tracked in the underlying models (and complementary data sources), which typically target direct emissions from the combustion of fossil fuels because this is the primary anthropogenic source for each air emissions type.

Electric sector air emissions are estimated directly from the ReEDS model, which represents all laws and regulations related to electric sector SO_2, NOx, and CO_2 emissions as of spring 2018. The impacts of electrification on air emissions for the broader energy system are complex and depend on the trade-off between non-electric emission intensities and power-sector emissions associated with electrified end uses. For this analysis, we estimate direct end-use emissions from the end-use equipment stock and service demands derived from the EnergyPATHWAYS model (Mai et al. 2018). For each end-use equipment type, vintage, and fuel type, emission factors translate final energy use (e.g., Figure 13) into emissions. See Appendix C for details of this calculation.[52]

Estimating current and future emissions factors is challenging, given the heterogeneity in technology characteristics and use, and uncertainties about future technology improvement in both electric and non-electric end-use technologies. Therefore, the following results should be interpreted only as estimates that are primarily meant to sense of directionality for the impacts of electrification on air emissions.

2.4.1 Electric Sector Air Emissions

Under Base Case assumptions, electric sector emissions trends follow from the previously presented generation mix results: the increased utilization of natural gas and renewable energy generators drive a reduction in the electric sector emissions *rates* (defined as electric sector emissions divided by total generation; top row of Figure 14), especially as higher-emitting sources retire over time. This reduction occurs across all levels of electrification, such that the electric sector emissions rates in 2050 are 50%–70% below 2018 values.

The isolated effects of electrification take the form of an accelerated reduction in electric sector emissions rates (top row of Figure 14). This effect primarily reflects the increasing displacement of coal-fired generation with lower-emitting renewable energy and natural gas-fired generation, the latter of which represent negligible sources of criteria pollutant emissions. In turn, even when accounting for the related increase in electricity generation required to meet growing demand, electric sector NO_X and SO_2 emissions are reduced by roughly 50% between 2018 and 2050 under Medium and High electrification (bottom row of Figure 14). By contrast, the absolute level of electric sector CO_2 emissions depends more directly on the level of electrification, due to the carbon content of natural gas (which is lower than that of coal, but still non-zero). As a result, electrification is found to drive an incremental increase in *electric* sector CO_2 emissions (compared to Reference electrification), which reflects the "transfer" of natural gas from end-user sectors into the electric sector under the Base Case scenario. In turn, absolute electric sector

other industrial processes, and NOx formed during agricultural processes. Other types of air emissions that have pronounced impacts but are beyond the scope of this analysis include particulate matter, mercury, and methane.

[52] The translation from final energy to direct end-use emissions is performed in EnergyPATHWAYS for energy CO_2 emissions, whereas the calculation of energy sector-wide SO_2 and NOx emissions is based on emissions factors from the Global Change Assessment Model (and derived from EPA MOVES for transportation) (Shi et al. 2017).

emissions remain roughly constant over time under the Base Case scenario with High electrification (bottom row of Figure 14).

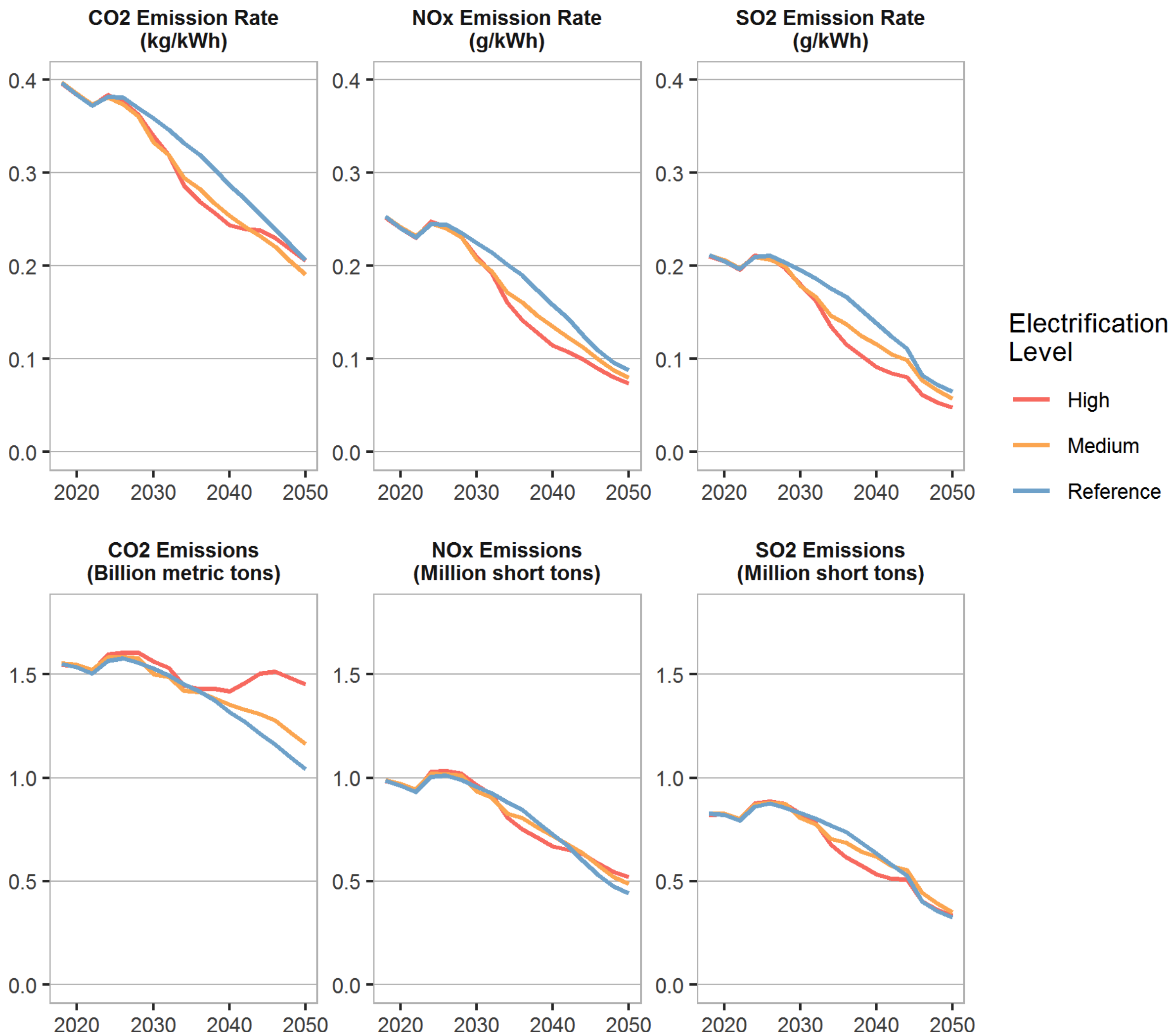

Figure 14. Electric sector emission rates (top) and absolute emissions (bottom) for CO_2 (left), NOx (middle), and SO_2 (right).

2.4.2 Energy-Sector Air Emissions

A more complete accounting of air emissions requires weighing electric sector emissions against corresponding changes in direct end-use emissions. To demonstrate this, we present energy-sector CO_2 emissions for the Base Case with different levels of electrification in Figure 15. Under Reference electrification (left panel), CO_2 emissions from direct fuel use in the end-use sectors are roughly flat over time, with slight increases in industrial sector emissions (due to economic growth) being offset by similar-magnitude reductions in transportation sector emissions (primarily due to increasing fuel economy). When combined with the previously observed reduction in electric sector emissions under the Base Case scenario with Reference electrification, the net result is a steady reduction in *energy*-sector CO_2 emissions over time.

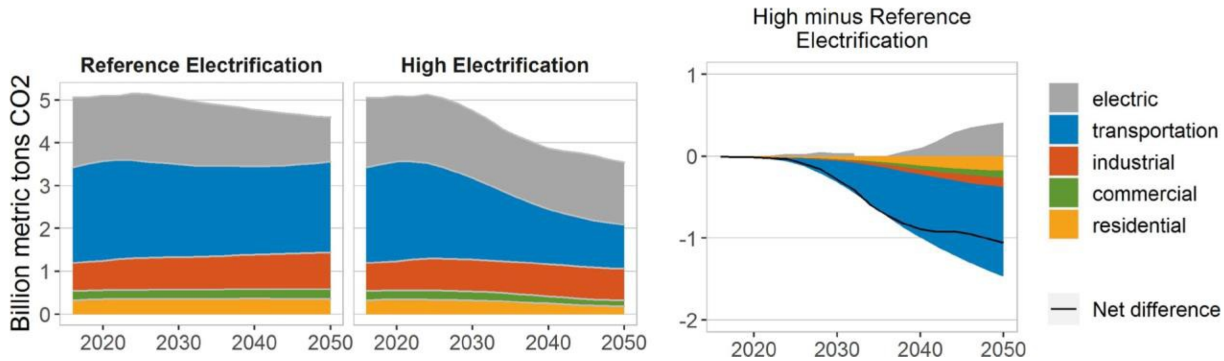

Figure 15. Energy-sector CO_2 emissions for the Base Case scenario with Reference and High electrification levels

Electric sector emissions are from ReEDS, and non-electric sector emissions are from EnergyPATHWAYS.

The picture is noticeably different under High electrification (middle panel, Figure 15), which drives a reduction in direct fuel use and, in turn, lower levels of CO_2 emissions from each end-use sector. High electrification drives the most pronounced reductions in transportation CO_2 emissions, which follows from the previously described reduction in petroleum consumption (Section 2.3.2). As a result, direct CO_2 emissions from the transportation sector are reduced by half in 2050 under High electrification (relative to Reference electrification; right panel). Combining this result with more-modest reductions from buildings and industry reveals 2.1 billion metric tons of end-use CO_2 emissions in 2050 under High electrification.

This electrification-driven reduction in direct end-use CO_2 emissions more than offsets the related increase in electric sector CO_2 emissions. The middle panel of Figure 15 demonstrates this trade-off, which results in an 30% reduction in energy CO_2 emissions in 2050 under the Base Case scenario with High electrification (relative to 2018 levels). High electrification results in a 1.1 billion metric ton (or 23%) reduction in energy CO_2 emissions in 2050, relative to the Reference electrification results in the same year (Figure 15).[53] Therefore, a key finding of this analysis is that High electrification would likely reduce energy-sector CO_2 emissions even in the absence of new electric sector emissions policies.

Similar themes arise when evaluating the effects of electrification on energy SO_2 and NOx emissions. For example, the tan bars in the top panel of Figure 16 demonstrate that the most pronounced effect of increasing levels of electrification is an accelerated reduction in direct NOx emissions from the transportation sector (which currently represent the largest share of anthropogenic NOx emissions). This trend reflects the increasing displacement of internal combustion engine vehicles (at the end of their useful life) with zero-emitting battery electric vehicles over time. However, the incremental effects of electrification are relatively modest through 2030, primarily due to the rapid near-term reductions in transportation NOx emissions under Reference electrification (see Appendix C) and relatively slow stock turnover rates.[54]

[53] Accounting for annual reductions across the analysis period (2018–2050), High electrification drives an 8.7 billion metric ton (10%) reduction in energy-sector CO_2 emissions, relative to Reference electrification.
[54] The relatively long lifetimes for personal vehicles mitigate the potential for electric vehicle adoption before 2030.

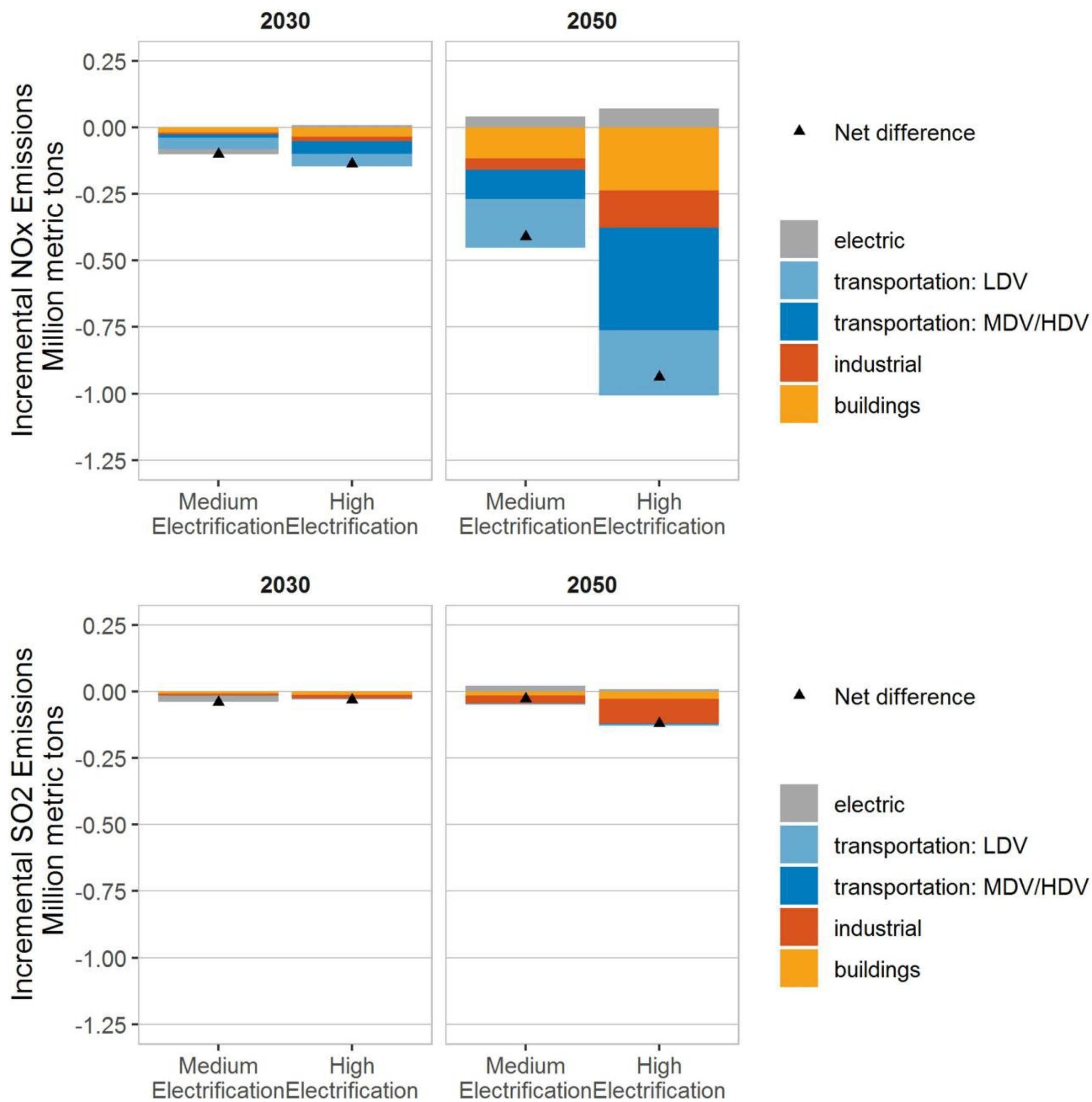

Figure 16. Effects of Medium and High electrification on energy-sector NOx and SO_2 emissions in 2030 and 2050, under Base Case assumptions

Electric sector emissions are from ReEDS, and non-electric sector emissions are estimated by combining EnergyPATHWAYS results with GCAM emission factors by technology type, vintage, and fuel type.

LDV = light-duty vehicle; MDV = medium-duty vehicle; HDV = heavy-duty vehicle

Considering a longer time horizon, more-pronounced differences arise between the Medium and High electrification results; this indicates that electrification beyond the sub-sectors with potentially lower barriers to electrification could further reduce energy NOx emissions. For example, High electrification drives the near-complete elimination of direct NOx emissions from light-duty vehicles by 2050 (~90% below 2018 levels and 80% below Reference electrification levels in 2050), while Medium electrification drives smaller-magnitude reductions. In addition, the incremental reductions in medium- and heavy-duty vehicle NOx emissions in 2050 grow from 12% under Medium electrification to 41% under High electrification. Combining these results with additional reductions in the other end-use sectors and modest incremental increases in electric sector NOx emissions under increasing levels electrification (Figure 14), the net effects of Medium and High electrification on energy NOx emissions in 2050 are found to be 11%–26% reductions (respectively) relative to Reference electrification, and 45%–54% reductions relative to 2018 levels.

Finally, the bottom panels of Figure 16 present the incremental effects of Medium and High electrification on energy SO_2 emissions. The most pronounced effects of electrification take the form of a reduction in industrial SO_2 emissions, the magnitude of which scales with the electrification level. This electrification-driven reduction is partially offset by modest incremental increases in electric sector SO_2 emissions (Figure 14), such that the net effects of Medium and High electrification are 1% and 9% reductions (respectively) in energy SO_2 emissions, relative to Reference electrification levels in 2050 (accounting for minor changes in building and transportation). Compared to 2018 levels, the Medium and High electrification results in 2050 correspond to 14% and 19% reductions in energy-sector SO_2 emissions.

3 Results: Demand-Side Flexibility Variations

Electrification of end uses could offer increasing opportunities for demand-side sectors to influence the evolution of the U.S. electricity system. Demand-side flexibility has the potential to modify electricity load profile shapes and peak load, the combination of which could influence electric system investment and dispatch decisions. Flexibility could also impact consumer investments and decisions, including offering new potential revenue streams for consumers that opt to provide flexibility to the grid. However, inconvenience to end users, diminished productivity, institutional and regulatory hurdles, and implementation costs might limit the expansion of flexible loads (e.g., Hledik et al. 2019). Given these uncertainties, this analysis explores a range of demand-side flexibility levels, which are summarized here and detailed in the companion EFS report (Sun et al. 2020).

The scenarios presented in this section include variations with all three demand-side flexibility levels for the Reference and High electrification levels and under Base Case assumptions for all other parameters (Table 2). Limiting the scenario analysis in this section to variations across these two dimensions (electrification and demand-side flexibility) allows for the exploration of two research topics: the unique impacts of demand-side flexibility on electric system evolution and how those impacts could vary with the increasing electrification of end-use equipment.

This analysis should be interpreted as an estimate of the value of load flexibility for the bulk power system rather than a full cost-benefit analysis.[55] The results from the demand-side flexibility sensitivities presented in this section provide initial estimates of nationwide impacts of flexible load, especially demand-side flexibility that might emerge from electrification. Simultaneously, varying other electric sector input assumptions (Table 3) would result in different absolute responses from the electric system, especially in future scenarios where the system is constrained in terms of its infrastructure development needs and options.

3.1 Modeling Demand-Side Flexibility

In ReEDS, demand-side flexibility is modeled as "load shifting," which can be thought of as the ability of a central planner to control or provide incentives for a fraction of a subsector's electrical load to move from one hour to another (or from one model time-slice to another; see Sun et al. 2020 for details). Though this representation does not capture all possibilities for flexibility (e.g., load shedding and provision of ancillary services such as vehicle-to-grid capabilities), it does capture multiple potential sources of value for flexibility beyond just energy arbitrage.[56] For example, shifting demand away from peak periods reduces the amount of planning reserves required in ReEDS. Similarly, because operating reserves are modeled as a function of the amount of demand (and VRE production), load shifting can also impact the amount of reserves needed during any given time-slice (Cole, Eurek et al. 2018).

In the present representation of demand-side flexibility, we first estimate the amount of flexible load that can potentially be shifted for each end-use subsector (Mai et al. 2018), based on the

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[55] See Hledik et al. (2019) for a focused analysis on the potential costs and benefits of enhanced load flexibility.
[56] Energy arbitrage is the practice of purchasing and storing electricity during low cost times and then utilizing that stored electricity when prices are higher (or shifting electricity demand from high- to low-cost times).

load characteristics and end-use technology distribution within the subsector. The load is then further constrained by assumptions about the:

1. Timing of shiftable load (e.g., commercial loads are generally assumed to only be flexible during work hours)
2. Direction load can be shifted (e.g., dishwasher load can only be postponed)
3. Duration load can be shifted (e.g., space heating has a one-hour flexible duration)
4. Customer participation rate (i.e., the proportion of customers willing to allow their load to be shifted).

To explain this modeling representation, we describe how these different constraints are represented for two potential key sources of demand-side flexibility: air conditioning and vehicle charging. Flexibility from air conditioning loads is only available during warmer periods in regions where air conditioners are installed, and with an assumed one-hour flexible duration.[57] For light-duty electric vehicles, we assume charging load can be shifted by eight hours, which may correspond to a shift in charging to overnight hours. Other assumptions that characterize the flexibility across sectors, subsectors, and devices are described by Sun et al. (2020).

The three levels of demand-side flexibility that are evaluated in this analysis—Current, Base, and Enhanced—all assume the same timing, direction, and duration of flexible load. Therefore, the levels of demand-side flexibility only vary based on the assumed participation rates for each sector. Current demand-side flexibility holds customer participation constant at estimated levels for existing demand response, variable pricing, and demand-side management programs. "Base" demand-side flexibility—which is relied on for all scenarios presented in other sections of this report—reflects the implementation of the most successful demand response programs in-place today (by sector) across the contiguous United States (EIA 2018d).

Finally, the Enhanced demand-side flexibility level represents an expansion of the most successful demand response programs into all sectors and regions of the contiguous United States (Kaluza, Almeida, and Mullen n.d.). Qualitatively speaking, Enhanced demand-side flexibility represents an increase in consumers' willingness to give utilities limited control over the timing of end-use equipment electricity use in exchange for sufficient financial incentives (or another mechanism);[58] however, our analysis does not assess or assume any specific mechanism to enable and compensate end-use flexibility, and thus the potential costs for these programs are not included in our results. Given significant uncertainties about future demand-side participation, Enhanced demand-side flexibility should not be interpreted as either realistic *or* an

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[57] We use flexibility duration to adjust the amount of flexible load available in each ReEDS time-slice for cases where the duration is less than the time-slice length, to avoid overestimating load shifting potential. For example, if flexible load with a one-hour shift duration occurs during a time-slice representing a four-hour period, one-fourth of the flexible time-slice load is assumed to be shiftable.

[58] Beyond financial incentives, other possible mechanisms include pricing signals (e.g., time-of-use rates or real-time pricing), utility incentive programs, utility owned and/or controlled equipment, or aggregators and virtual power plants.

upper bound, but rather a mechanism for evaluating how the value of demand-side flexibility might change with increasing penetration.

Combining the assumed customer participation rates for each level of demand-side flexibility with fixed assumptions about flexibility potential, timing, direction, and duration, the amount and percentage of load that can be shifted in each subsector is calculated and presented in Table 8.[59] Because the amount of flexible load scales with sector-specific electricity demand, scenarios with greater electrification (for a given level of demand-side flexibility) have greater amounts of absolute flexible load. For example, under Reference electrification, most demand-side flexibility is attributed to growing participation rates in residential flexibility programs over time (Text Box 2), regardless of the assumed level of demand-side flexibility (Table 8, Figure 17). By contrast, the expanded adoption of electric vehicles and increasing participation rates over time result in the transportation sector providing the largest share of flexible load (Text Box 3) under High electrification in 2050 (e.g., Figure 17), regardless of the demand-side flexibility level.

In practice, this flexible load is "dispatched" in ReEDS by shifting electricity demand between time-slices to minimize total bulk electric system costs.[60] The effects of load shifting reflect both short-run dispatch and long-run investment decisions, which are considered simultaneously in ReEDS; therefore, the following results reflect their net effects.

Table 8. Flexible Load[a] in 2050, by Sector and for Total Load

Electrification Level	Demand-Side Flexibility Level	Transportation Sector	Residential Sector	Commercial Sector	Industrial Sector	All Sectors[b]
Reference	Current	4 TWh (4%)	13 TWh (1%)	3 TWh (<1%)	8 TWh (1%)	27 TWh (1%)
	Base	12 TWh (13%)	65 TWh (4%)	14 TWh (1%)	22 TWh (2%)	113 TWh (2%)
	Enhanced	55 TWh (58%)	195 TWh (13%)	42 TWh (2%)	65 TWh (5%)	357 TWh (7%)
High	Current	52 TWh (3%)	11 TWh (1%)	4 TWh (<1%)	10 TWh (1%)	77 TWh (1 %)
	Base	191 TWh (12%)	62 TWh (4%)	20 TWh (1%)	27 TWh (2%)	299 TWh (4%)
	Enhanced	825 TWh (51%)	187 TWh (12%)	60 TWh (3%)	80 TWh (5%)	1,151 TWh (17%)

[a] Entries include (1) absolute flexible load (TWh) and (2) percentage of flexible load (i.e., flexible load divided by total load), both of which are presented for individual sectors and for all sectors in aggregate.

[b] Load from all sectors may not equal the sum of loads from individual sectors due to rounding.

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[59] Flexible load amounts are presented in energy (TWh) units rather than capacity (GW) units because the latter depends on the coincidence of the flexible load, given the constraints on utilizing the flexibility and how it is optimally "dispatched" by the model. Therefore, the extent to which flexible load could avoid or defer new capacity is a modeling *outcome* presented below.

[60] Because the present implementation of ReEDS only tracks the aggregate load profile following the "dispatch" of flexible load, resolving how much or which sector's load is shifted it is not possible.

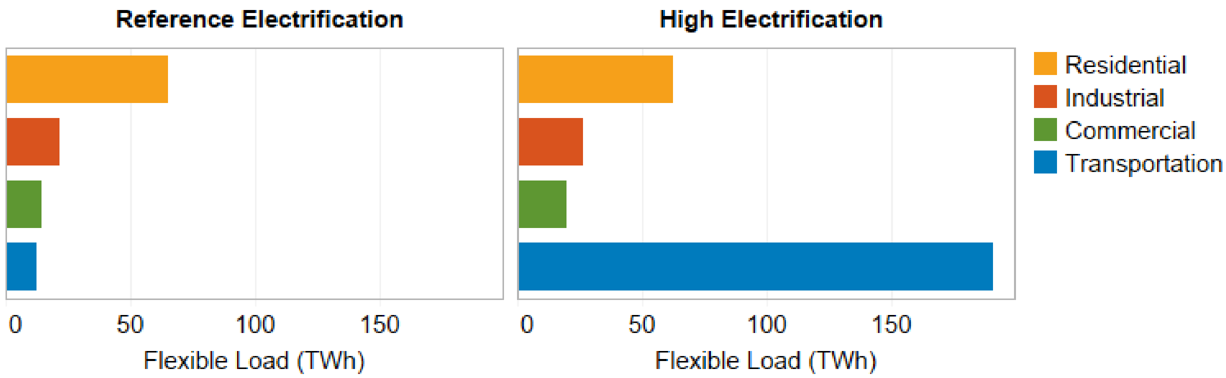

Figure 17. Flexible load by sector with Base flexibility in 2050 for Reference and High electrification

Text Box 2. Demand-Side Flexibility from Residential and Commercial Buildings

The sources of demand-side flexibility that were included in this EFS analysis were primarily derived from the end-use equipment that Mai et al. (2018) identified as having potential for beneficial electrification, such as building space and water heating, other building appliances, vehicles, and industrial processes. Across the different end-use services considered, those attributed to residential and commercial buildings are assumed to be highly flexible, based on the share of demand within a given end-use service that is assumed to be flexible. For example, all load from *participating* residential dishwashers, clothes washers, clothes dryers, and water heating is assumed to be shiftable over an eight-hour period. It is also assumed that all participating space heating and conditioning—primarily from air source heat pumps—is flexible, but that the corresponding load can be only be shifted over a one-hour period.

Despite this level of flexibility, buildings represent a small share of total flexible load under High electrification (in units of terawatt-hours; Sun et al. 2020). This result partially arises from the fact that appliances and other electrified equipment in buildings are assumed to become highly efficient, which limits the amount of energy that can be shifted in time for a given end-use service. Additional sources of demand-side flexibility in buildings were not considered in this analysis because they do not represent explicit fuel-switching opportunities or they require additional infrastructure deployment. For example, "add-on" technologies that enhance the flexibility of buildings (e.g., ice storage system for commercial HVAC), non-electric technologies that provide flexibility (e.g., phase change materials or photochromic windows), and structural changes that could enhance flexibility of HVAC technologies (e.g., greater levels of insulation and air sealing) were not included. Though these sources of flexibility would not scale directly with electrification, they have could provide benefits to both the grid and consumers, particularly under increasing and changing electricity demand profiles.

Text Box 3. Demand-Side Flexibility from Vehicles

Of the sources of demand-side flexibility included in this EFS analysis, most electrification-enabled demand-side flexibility arises from light-duty, medium-duty, and heavy-duty vehicles. In particular, the transportation sector's share of total flexible load in 2050 grows from ~10% under Reference electrification, to more than 60% under High electrification, the vast majority of which is derived from the light-duty vehicle (LDV) fleet. This prominent growth in vehicles' contribution to demand-side flexibility under High electrification reflects three factors: the transportation sector represents a significant fraction of final energy demand, there is widespread potential for the electrification of certain transportation services, and early data indicate that properly-designed demand-response programs could result in flexibility in the scheduling and guiding of EV charging.

EV charging is assumed to be highly flexible in this analysis, with all commercial vehicles able to shift their load by up to 6.5 hours during the night, and 75% of light-duty passenger vehicles able to shift their charging load by up to eight hours (before or after the baseline charging start time). This representation assumes participating EVs will have the option of charging at different locations (e.g., residential and workplace) and that charging could be postponed across multiple days, leading to flexibility in "anticipating" charging by up to eight hours in the following day. These parameterizations for flexible EV charging were chosen based on existing data, as described below.

The assumed duration for the flexibility of EV charging for different vehicle classes was informed by existing travel and service data, compared against the electric vehicle performance assumptions from Jadun et al. (2017). In general, these assumptions reflect optimistic flexibility durations while ensuring that the ability to shift EV charging does not preclude achieving mobility needs for passenger and freight vehicles. For commercial vehicles, we assume daytime operation and ability to shift load during the night. For LDVs, existing data indicate that the vast majority of trips and 70% of daily driving are both under 40 miles, while 95% of daily driving is under 100 miles (Wood et al. 2017). Compared to EV ranges (and trends showing increasing range in newer models), this suggests an ability to accommodate shifts in the timing of LDV charging, along the lines of what assumed in this analysis.

Because the EV market in the United States is nascent, existing data about the extent to (and mechanisms by) which EV drivers could be encouraged to participate in flexible EV charging programs takes the form of early pilot studies (Kaluza, Almeida, and Mullen. n.d.; EPRI 2018b). Results from these early pilot studies suggest that EV drivers could be willing to provide flexibility as long as (1) they are not inconvenienced, (2) they are not limited in their ability to use their vehicles, (3) simple automatic control systems are available to schedule EV charging, and (4) workplace charging infrastructure is made available to enable longer charging postponements and mitigate "range anxiety." While these early data indicate great potential for flexible EV charging under the right incentives, significant questions remain about whether each of these caveats will be realized—particularly the universal availability of workplace charging—and whether the observed trends will hold across a broader geographic range and customer base.

Finally, it is worth noting potential barriers to and benefits associated with the demand-side flexibility, as modeled in the EFS so far, many of which represent active research questions. For example, what are the communications and infrastructure (e.g., charging stations for EVs) requirements to implement widespread and reliable demand response programs? What are the business models and market incentives required to achieve the participation levels assumed and to compensate the final consumer for providing flexibility in their electricity consumption? To what extent could utilities be incentivized to develop these programs, so as to avoid distribution system upgrades that could otherwise be needed under widespread EV adoption? While operations of commercial vehicles vary for different applications and are constrained by logistics considerations, could the timing of truck charging be optimized to align with less-expensive charging hours? Finally, what are the potential *benefits* associated with widespread EV adoption, which could be thought of as a form of distributed storage if the right technical and institutional solutions are in place to facilitate the use of EVs as a resource on the distribution system?

3.2 Power System Evolution

Under High electrification and at a national level, the optimal dispatch of flexible load results in a shifting of electricity demand from the afternoon and evening time-slices into the overnight and morning hours.[61] In turn, increasing levels of demand-side flexibility drive increasing reductions in coincident peak demand and avoided capacity, both of which are presented in Table 9. While these metrics reflect related trends, their magnitudes differ because regional peaks may not coincide; planning reserves are met regionally (although trading is allowed in our model); and there are significant variations in estimated capacity credits between technologies, scenarios, and regions. Moreover, the changes in load shape can affect the economics of different generation sources, based on their profiles, dispatchability, and cost and capabilities for providing reserves.

Table 9. Coincident Peak Demand[a] and Installed Capacity in 2050 by Flexibility Level

	Reference Electrification			High Electrification		
	Current	Base	Enhanced	Current	Base	Enhanced
Coincident peak demand (GW)	940	930	910	1,410	1,360	1,270
Installed capacity (GW)	1,690	1,670	1,630	2,490	2,440	2,340

[a] Peak demand represents end-use demand, and it does not include transmission or distribution losses.

To demonstrate the net effect of these factors, Figure 18 presents how investment and dispatch decisions change with increasing levels of demand-side flexibility (based on system-wide least-cost optimization in ReEDS). Under both Reference (left) and High (right) electrification, Enhanced demand-side flexibility drives a delay in near-term capacity additions and a lower amount of cumulative installed capacity through 2050. Under Reference electrification, a net reduction of 40 GW in installed capacity is found between the Enhanced and Base demand-side flexibility in 2050 (top left panel in Figure 18), compared to the 100 GW of avoided capacity that is estimated under High electrification (top right panel). Together, these results suggest that flexible load could reduce the *incremental* amount of capacity needed by ~60 GW to meet electrification-driven demand, and therefore the overall infrastructure development that would be attributed to increasing electrification.[62]

Demand-side flexibility's impact on individual technologies varies over different time periods and electrification levels. Figure 18 shows that Enhanced demand-side flexibility reduces the need for new NG-CC and PV capacity from the mid-2020s through the 2040s, regardless of the level of electrification. Recall, however, that these two technologies experience pronounced growth over time under all Base Case scenarios (Section 2.1.1); therefore, after accounting for the reduced amounts of capacity from greater flexibility shown in Figure 18, NG-CCs and PV still experience absolute growth over time and incremental growth due to High electrification.

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[61] However, subnational results can differ such that regions with high solar penetrations typically shift their load from the morning and evening time-slices to the afternoon ones, if possible. See Sun et al. (2020) for details.
[62] As shown in Table 9, the Base demand-side flexibility level reduces the *incremental* total capacity needs in 2050 by about 30 GW compared to Current flexibility (i.e., comparing the differences between High and Reference electrification versions of Default and Current demand-side flexibility).

These flexibility-driven reductions in the deployment of new NG-CC and PV capacities are partially offset by lower levels of coal retirements as well as additional incremental growth in wind. By the end of the analysis period, the impacts of Enhanced demand-side flexibility on PV and wind capacity are more muted, but more-pronounced reductions are observed in peaking capacity (NG-CTs and batteries). The latter result reflects the similar roles that flexibility of electricity demand and supply play in ReEDS.

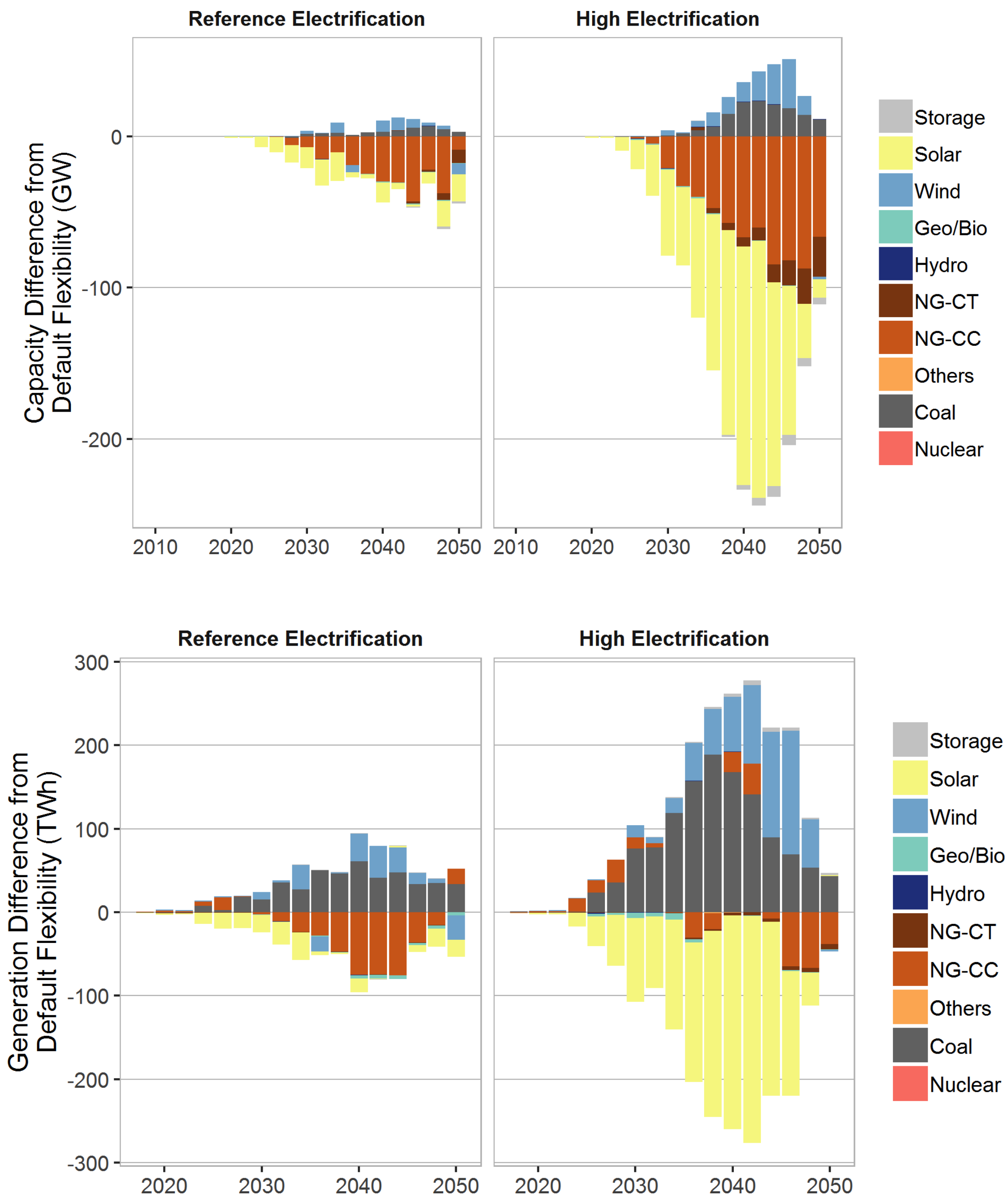

Figure 18. Effect of Enhanced demand-side flexibility (versus Base) on capacity (top) and generation (bottom) under Reference and High electrification

Similar themes are apparent in the impacts of Enhanced demand-side flexibility on the generation mix (Figure 18, right panels), including (a) increased generation from coal and wind, due to the increased demand during the overnight and morning hours[63] and (b) reductions in PV generation. Increasing levels of demand-side flexibility further lead to the increased utilization of many generator types, including higher capacity factors for coal-fired power plants from the mid-2020s through the mid-2040s. In addition, despite the flexibility-driven reduction in NG-CC capacity, the level of generation from NG-CCs remains largely unchanged across flexibility levels; as a result, the average capacity factors of NG-CCs increase from ~44% under Base, to ~47% under Enhanced demand-side flexibility with High Electrification in 2050. Finally, VRE curtailment rates are slightly reduced under Enhanced demand-side flexibility (1.6%) relative to those observed under Base demand-side flexibility (1.8%). Altogether, these results highlight how demand-side flexibility can support the increased utilization of generation assets, thereby reducing the need for new capacity.

3.3 Broader Impacts

Because our representation of demand-side flexibility is limited to load shifting, many of the impacts of electrification that were presented in Section 2 apply to the scenarios in this section as well. For example, demand-side flexibility has a negligible effect on primary energy consumption (and no effect on final energy), because the total annual load is constant across flexibility levels. Moreover, even when accounting for changes to the generation mix, variations in energy-sector natural gas consumption and the amount of primary energy attributed to the electric sector are small (<1%). Finally, demand-side flexibility has a modest impact on electric sector air emissions (following from the generation mix results in Section 3.2), such that energy-sector air emissions are reduced by a similar amount under Reference and High electrification.

Given the similarities in all energy consumption and emissions impacts, this section focuses on how Enhanced demand-side flexibility impacts the system cost metrics presented in Section 2.2. It is important to note that results regarding flexibility-driven impacts on bulk electric system costs do not account for any incremental costs associated with (1) changes in distribution system costs or (2) actualizing the load shifting, such as the corresponding communications equipment and administrative costs. Beyond the accounting issue that directly follows from the latter assumption, this limitation means the available demand-side flexibility is always the least-cost flexibility option available, so it is not competing on an economic basis with other flexible technologies. Therefore, the estimates provided here should be interpreted as an estimate of the value of load flexibility for the bulk power system rather than a full cost-benefit analysis.

Within the context of this guidance, we find that Enhanced demand-side flexibility provides value by (1) reducing total bulk electric system costs in all scenarios (independent of electrification level) and (2) mitigating some of the electrification-induced cost increases. The first result is demonstrated by the orange arrows and values in Figure 19 (page 45), which indicate that bulk electric system costs decrease with increasing levels of flexibility (regardless of the assumed level of electrification). These savings primarily come from reductions in capital expenditures (associated with the avoided natural gas-fired and PV capacity additions), which

[63] The resulting load profile shape is flatter, which allows for the increased utilization of coal-fired power plants. In addition, shifting load from daylight- into nighttime-hours increases the competitiveness of wind over solar.

more than offset incremental increases in fuel expenditures (associated with increased coal-fired generation; see Section 3.2). These results indicate that the primary benefit of flexible load—from a system-cost perspective—is deferring and reducing the need for new capacity.

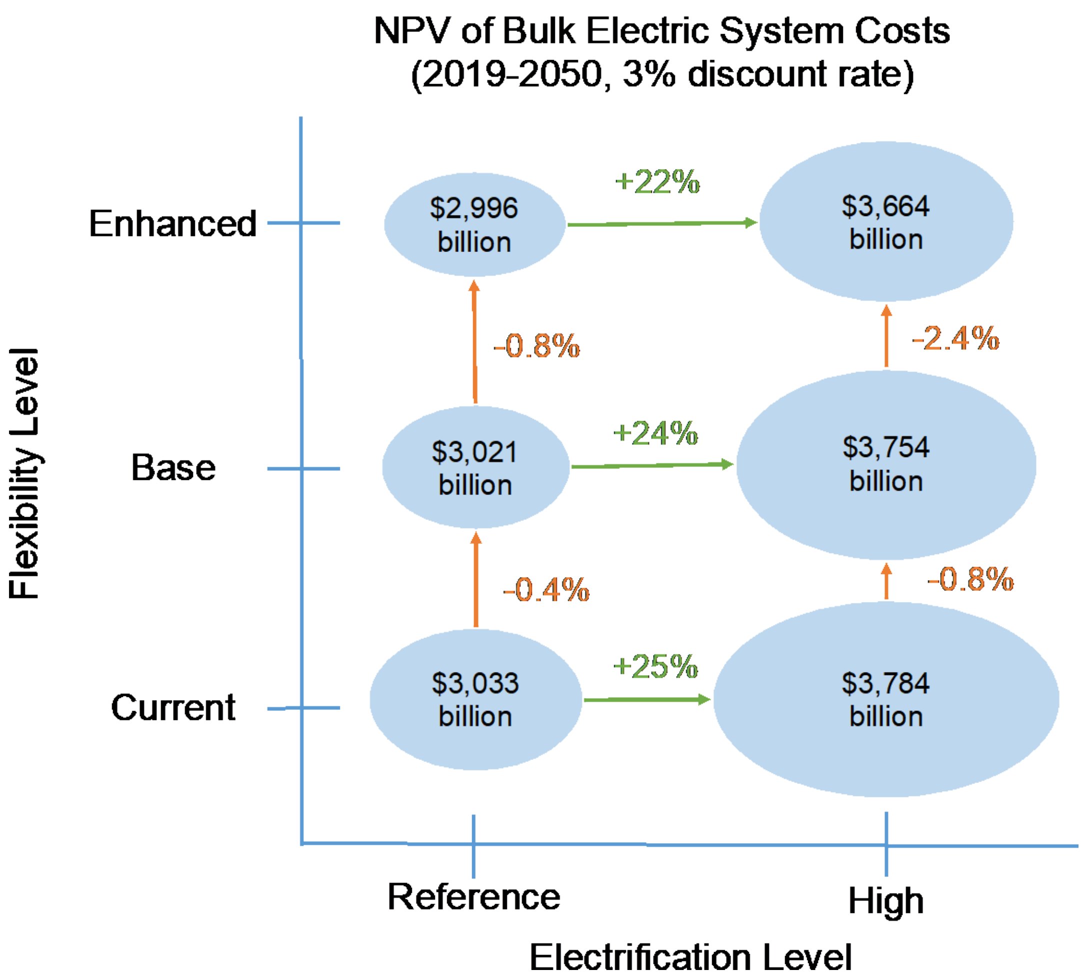

Figure 19. Present value of total electric system cost for Reference and High electrification across three levels of demand-side flexibility

Numbers in orange reflect percentage changes in bulk electric system costs with increasing levels of flexibility (for a given level of electrification); numbers in green reflect percentage changes from the corresponding Reference electrification for a given level of flexibility; the size of each oval scales with the cumulative net present value of bulk electric system costs, which is denoted in the oval (in units of 2016$).

To evaluate whether there are diminishing returns with increasing levels of demand-side flexibility, we report another metric that levelizes these system cost savings (across demand-side flexibility levels) by the corresponding increase in the magnitude of flexible load (megawatt-hours). Based on this metric, increasing from Current to Base demand-side flexibility results in levelized system cost savings of $19/MWh, whereas increasing from Base to Enhanced demand-side flexibility results in levelized savings of $16/MWh, all under High electrification. A similar trend is observed under Reference electrification, with corresponding results of $15/MWh and $11/MWh (respectively).

Multiple insights arise from a comparison of these results. First, regardless of the assumed level of electrification, we find that there may be diminishing savings with increasing levels of demand-side flexibility. However, given the wide range of flexibility assumptions explored in this analysis, the rate of reduction is likely fairly modest. Second, the value of demand-side flexibility could grow with increasing levels of electrification. Third, across the full range of electrification and demand-side flexibility levels explored in this analysis, we find an approximate value for demand-side flexibility of \$10–\$20/MWh. The latter result should be interpreted within the context of many sources of uncertainty, including the assumption of full system-wide optimization for load shifting, necessary parameterizations given the fidelity of the modeling, and a lack of barriers and costs to implementing and operating demand-side programs. More-detailed analysis is needed to assess these factors, but these initial estimates highlight the opportunity for system cost savings if this type of demand-side flexibility were realized.

A related assessment lies in the effects of demand-side flexibility on *incremental* bulk electric system costs. In particular, comparison of the green values in Figure 19 reveals that the electrification-driven increase in investment on the bulk electric system is reduced under increasing levels of demand-side flexibility. For example, the present value of bulk electric system costs are incrementally increased by \$730 billion (24%) under High electrification (relative to Reference electrification) with Base flexibility; by comparison, the incremental bulk electric system cost impacts of High electrification decline to \$670 billion (22%) with Enhanced flexibility, and they increase to \$750 billion (25%) with Current flexibility. This result primarily reflects that increasing levels of demand-side flexibility systematically lower peak demand, which results in reduced incremental costs associated with capital investments to meet growing demand under High electrification. However, recall that these results do *not* account for any “enabling costs” or financial compensation associated with realizing that flexibility.

4 Results: Electric Sector Variations

Building on the previous sections that explored variations in the adoption, advancement, and flexibility of electric end-use technologies, this section explores how various supply-side assumptions could influence the energy system's response to electrification. Sensitivity scenarios are constructed by applying established ranges for select supply-side assumptions (Cole, Frazier et al. 2018) under Reference and High electrification, while holding the end-use technology advancement and demand-side flexibility levels fixed at Moderate and Base levels.

The supply-side sensitivity scenarios can be grouped into two categories: fuel and technology sensitivities, and system constraints. The first category reflects variations around natural gas prices (via estimates for the underlying resource that impact those prices) and renewable energy technology costs, which are among the most influential factors affecting the evolution of the power sector (e.g., Cole, Frazier et al. 2018). However, future trajectories for these influential factors are highly uncertain (Figure 20, page 48).[64] This scenario analysis provides a symmetric representation of the assumption presented in Figure 20 (e.g., high- and low-cost and performance trajectories for renewable energy technologies); however, the two directions for a given sensitivity parameter should not be considered to be equally likely. Beyond this symmetric representation, the combined effects of the Larger NG Resource and Lower RE Cost scenario definitions are also modeled, to explore the nature of interaction between low-cost variations of these generating technology classes (Table 10, page 49).[65]

The second category of supply-side sensitivities evaluates how the effects of electrification could vary under difficult-to-model economic and noneconomic constraints on power system development. For example, power plant retirements depend on plant-specific conditions that reflect the financial health of the power plant as well as regulatory- and reliability-based considerations. The results presented in Section 2 for the Reference electrification scenarios demonstrated that the retirement of existing generators inherently drives a need for new power system infrastructure, beyond the purely electrification-driven needs. However, if constraints on the retirement of existing plants arise, the electrification-driven need for new capacity development would likely be reduced. Therefore, we explore a scenario representing Retirement Constraints to assess how electricity supply and the broader impacts under widespread electrification could be altered if existing coal and nuclear capacities are maintained for a longer period of time (Table 10, page 49), relative to the default assumptions in ReEDS.

[64] Figure 20 is presented to indicate the level of cost reductions assumed only. In practice, ReEDS does not compete technologies based on LCOEs, as it considers a technology's system value in its decision-making and includes regional capital cost multipliers, grid interconnection costs, and long-distance transmission costs as well. Also, the renewable energy technology cost sensitivities modeled in this analysis reflect variations to concentrating solar power, offshore wind, hydropower, geothermal, and utility-scale battery storage technologies (see Appendix B).
[65] Figure 20 and the recent trend toward lower expected prices over the past several years represent reasons we have modeled additional sensitivities using AEO2018 HOGRT (as opposed to LOGRT).

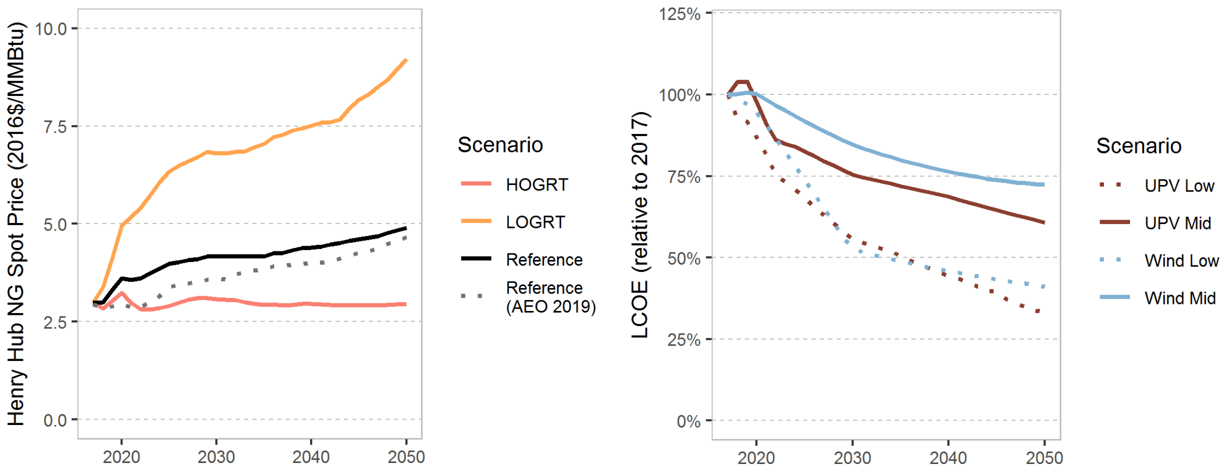

Figure 20. Natural Gas Henry Hub spot prices from the AEO (left) and renewable technology costs from the ATB (right).

Utility-scale PV (UPV) and onshore wind LCOEs are directly from the ATB 2018 using "market financials," a 20-year capital recovery period, no wind production tax credit, and a 10% solar investment tax credit. The uptick in LCOEs immediately after 2017 in the "Mid" cases are due to changes in finance assumptions from the ATB.

ReEDS endogenously estimates natural gas prices using supply curves (Sun et al. 2020 describe the method employed), so prices in our scenarios differ from those shown in the figure. Furthermore, delivered prices (for all end uses including for power generation) differ from Henry Hub prices and can vary by region.

HOGRT = high oil and gas resource and technology

LOGRT = low oil and gas resource and technology

A second system constraint scenario evaluates the potential effects of constrained emissions on the power system, which encourages zero-emitting (renewable energy and nuclear) and lower-emitting (carbon capture and storage) generation technology options within the model. Under the Emissions Constraints scenario, annual and national limits on direct CO_2 emissions from electricity generation are applied (Table 10, page 49), following the scenario definitions in NREL's 2018 Standard Scenarios (Cole, Frazier et al. 2018).

A final aspect relates to transmission expansion, which can be challenging to model given the wide array of factors that could affect the success of a new transmission project. The ReEDS model relies on high-spatial resolution to co-optimize transmission and generation expansion decisions that are informed by regionally varying transmission and generation costs, among other factors (see Section 1.2 and Cohen et al. 2019). However, the system-wide least-cost framework of ReEDS does not allow it to fully consider multiple transmission-related factors, including siting and permitting issues, cost allocation challenges, the inherent multi-jurisdictional nature of long-distance transmission, and potential technical power systems engineering-related factors.[66] Therefore, we assess a scenario Transmission Constraints that represent barriers to transmission expansion (Table 10, page 49).

[66] ReEDS cannot reflect all the local preferences or constraints and therefore may underestimate the need (or desire) for specific types of local resources, such as offshore wind and distributed energy resources.

Table 10. Scenario Definitions for Electric Sector Sensitivities[a]

Scenario Name	RE and Storage Technology Costs[b]	Natural Gas Resource Estimates	Other
Base Case[c]	Mid	AEO2018 Reference	-
Lower RE Cost[c]	Low	AEO2018 Reference	--
Constant RE Cost	Constant and High	AEO2018 Reference	--
Smaller NG Resource	Mid	AEO2018 Low Oil and Gas Resource and Technology (LOGRT)[d]	--
Larger NG Resource[c]	Mid	AEO2018 High Oil and Gas Resource and Technology (HOGRT)[d]	--
Combined (Larger NG Resource & Lower RE Cost)	Low	AEO2018 HOGRT[d]	--
Retirement Constraints	Mid	AEO2018 Reference	Coal plant lifetimes increased by 10 years; no retirement of underutilized coal plants; all nuclear plants have 80-year lifetimes.
Emissions Constraints[c]	Mid	AEO2018 Reference	Power sector emissions capped at 30% below 2005 levels by 2025, 83% by 2050.
Transmission Constraints	Mid	AEO2018 Reference	3x transmission capital cost; No new AC-DC-AC interties; 2x transmission loss factors[e]

[a] Reference and High electrification levels are modeled for each scenario. Default assumptions (Table 2, page 8) are used for all other assumptions, including Moderate end-use technology advancement and Base flexibility.
[b] RE technology costs are from the 2018 ATB, and battery energy storage technology costs are from Cole, Marcy et al. 2016.
[c] Results from these scenarios with Reference and High electrification were presented in Murphy et al. (2020).
[d] The High Oil & Gas Resource and Technology (HOGRT) case assumes 50% greater estimated recovery for tight oil, tight gas, and shale gas compared to the Reference. Undiscovered resources and rates of technology improvements for resource extraction are both increased by 50%. The Low Oil & Gas Resource and Technology (LOGRT) case assumes 50% differences in the opposite direction.
[e] Default long-distance transmission costs range from \$650/MW-mile to \$6,000/MW-mile. ReEDS assumes a default transmission loss rate of 1% per 100 miles.

4.1 Power System Evolution

Consistent with many previous studies, this analysis finds that varying the input assumptions about future fuel prices, technology costs, and system constraints has a pronounced impact on the future capacity mix. To demonstrate this, Figure 21 presents the cumulative (top) and incremental (bottom) effects of High electrification on the 2050 capacity mix for the full range of supply-side sensitivities (Table 10, page 49). Comparison across these results reveals a variety of new findings regarding power sector infrastructure development under High electrification.

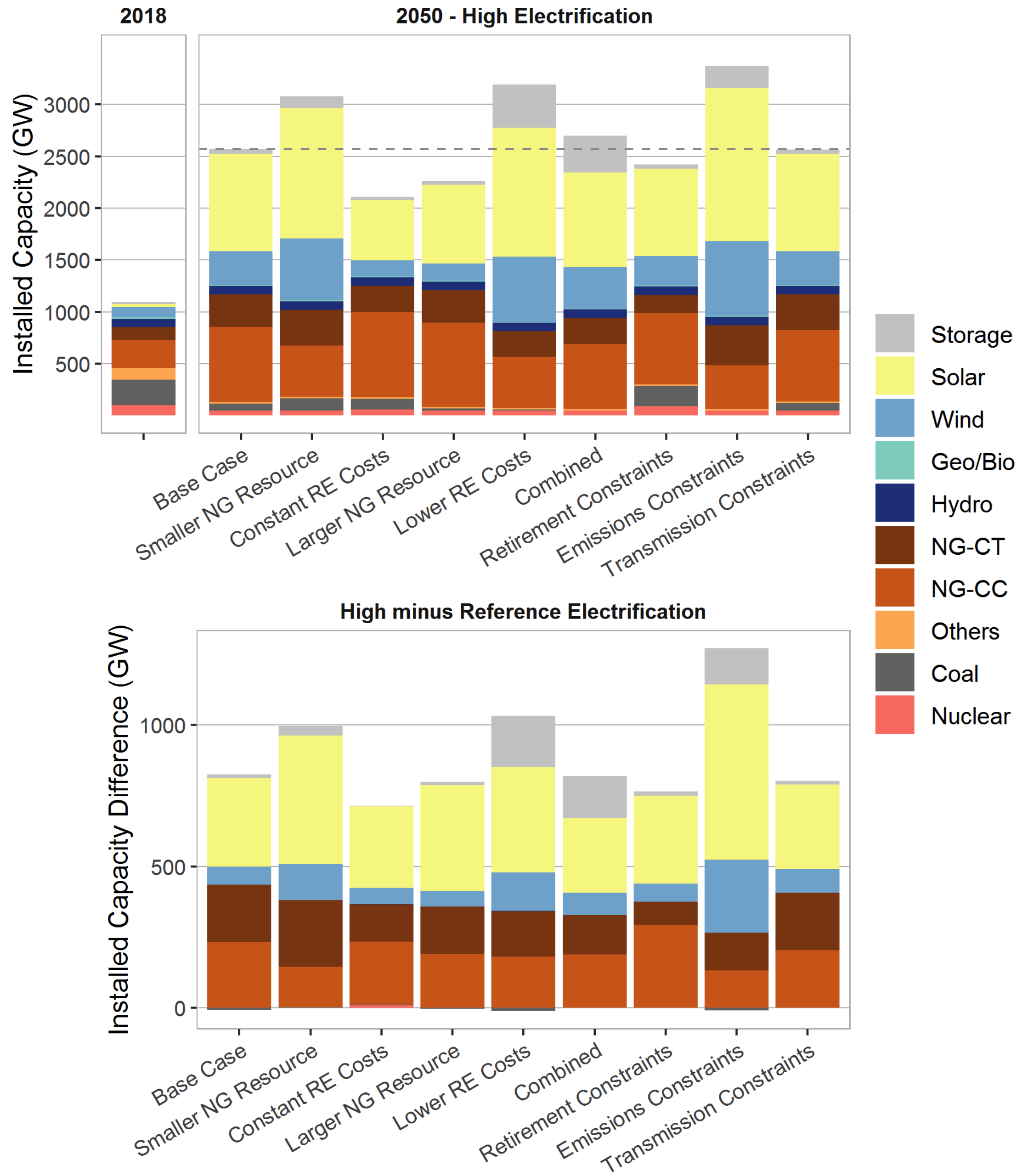

Figure 21. Comparison of 2018 and future installed capacity mixes under High electrification versions of all fuel, technology, and system constraint sensitivities

2018 values represent ReEDS model results for the Base Case scenario with Reference electrification.

First, the aggregate level of generation capacity that would be required by 2050 to meet the growing loads with High electrification is highly uncertain, as indicated by the different total heights for the bars across electric sector sensitivities. The wide range of results primarily depends on the growth in natural gas versus renewable energy capacity, which have an inverse relationship. Lower RE Costs, a Smaller NG Resource, and Emissions Constraints[67] each drive

[67] Approximately 5 GW of incremental NG-CC capacity in this scenario includes carbon capture and storage.

the electric system to rely heavily on renewable energy technologies under High electrification, which results in up to a near-tripling of installed capacity between 2018 and 2050. Inversely, Constant RE Costs and a Larger NG Resource drive the electric system to accommodate electrification primarily with natural gas-fired technologies, which results in a smaller amount of cumulative installed capacity under High electrification.

Unique insights also arise from the scenarios in which the level and mix of 2050 installed capacity are closer to those observed under the Base Case. First, similarities between the Combined and Base Case scenarios indicate an effective balancing of the opposing effects of the underlying assumptions (a Larger NG Resource and Lower RE Costs). Second, despite the similar levels of aggregate capacity under the Base Case and Retirement Constraints, the latter scenario involves an additional 130 GW of coal-fired capacity and 40 GW of nuclear capacity in 2050. This maintained coal and nuclear capacity reduces the need for new natural gas and renewable energy capacity, relative to the Base Case scenario (bottom row of Figure 21). Third, comparison of results for the Base Case and Transmission Constraints scenarios reveals that representing barriers to transmission expansion has a negligible impact on the level and mix of installed capacity in 2050, even under High electrification (Figure 21). The latter similarity is notable because it suggests a combination of (1) adequate availability in the existing transmission network and (2) abundant local resources to meet the increased load under widespread electrification, with a similar resource mix. Moreover, it demonstrates that ReEDS is able to accommodate High electrification even when assuming significant barriers to long-distance transmission system expansion and utilization.

Figure 22 depicts the latter result more directly, by showing future transmission capacity growth for the High electrification versions of each electric sector sensitivity. The far-right bar demonstrates that the Transmission Constraints scenario accommodates High electrification with a mere 2% increase in long-distance transmission capacity between 2018 and 2050. This result is smaller than the level of long-distance transmission expansion observed under either the Transmission Constraints scenario with *Reference* electrification (bottom row) or the Base Case scenario with High electrification (12% growth between 2018 and 2050; far-left bar).

This limited amount of long-distance transmission expansion under Transmission Constraints is made possible by two effects: increased flows along the existing transmission network and the increased deployment of spur line capacity (tan bar). Spur line capacity ultimately represents the vast majority of new transmission capacity under the Transmission Constraints scenario. In turn, *total* transmission capacity expansion is comparable across the Transmission Constraints (18% growth between 2018 and 2050) and Base Case scenarios with High electrification (27%–35% growth), which helps explain their similar capacity mixes (Figure 21).

Zooming out to consider the full range of supply-side sensitivities, comparison of the cumulative (top) and incremental (bottom) results indicates that the optimal amount of new transmission capacity is more sensitive to supply-side assumptions than it is to electrification (Figure 22). Scenarios that represent High electrification with a Smaller NG Resource or Emissions Constraints result in pronounced increases in both long-distance (34%–45%) and total transmission capacity (72%–75%) by 2050, relative to 2018 levels. By contrast, assuming a Larger NG Resource or Constant RE Costs leads to transmission expansion levels that begin to approach those under the Transmission Constraints scenario (described above). This wide range of transmission expansion results across sensitivity scenarios exceeds the observed incremental effects of electrification (bottom row).

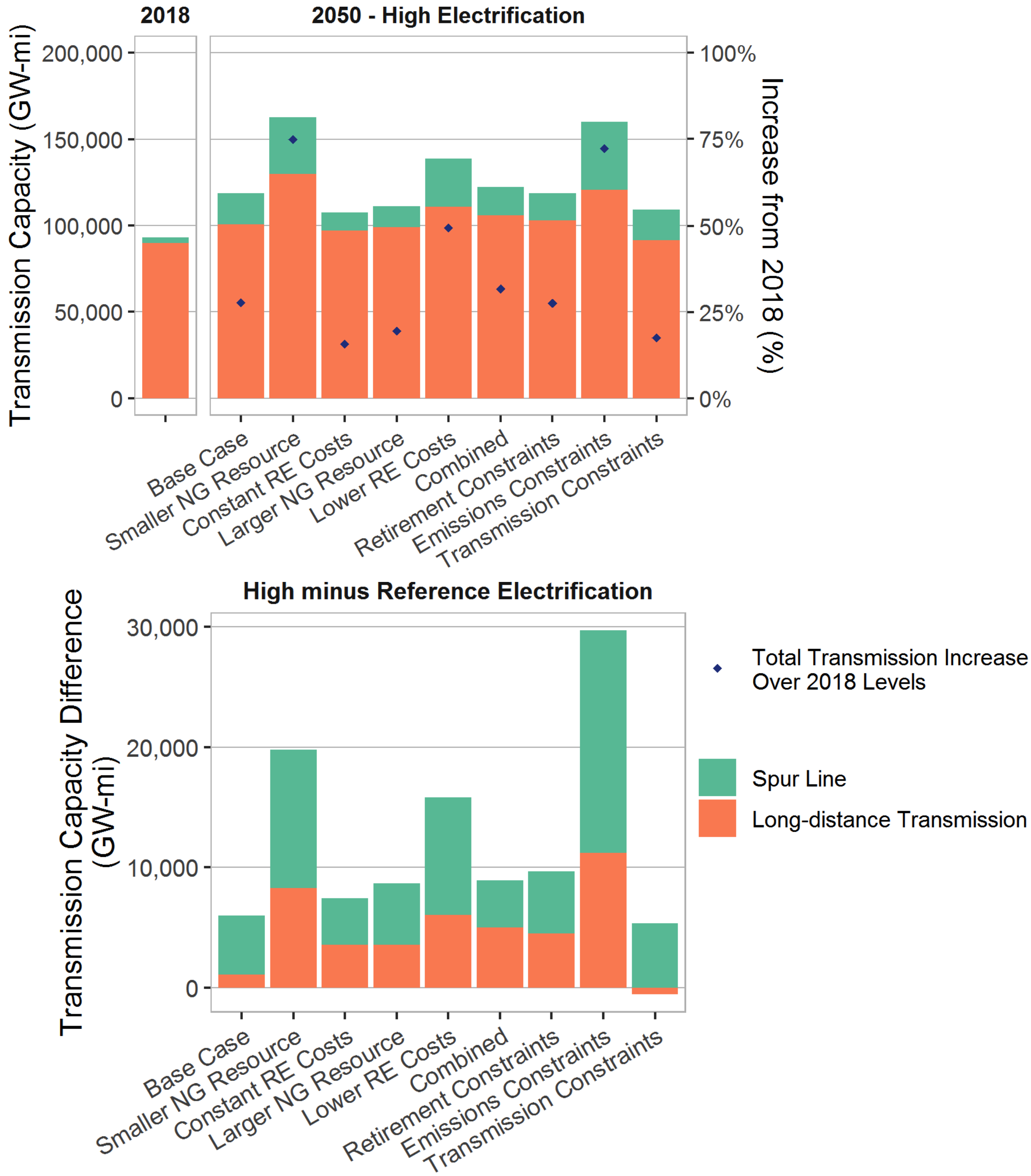

Figure 22. Cumulative (top) and incremental (bottom) effects of High electrification on 2050 transmission capacity across all fuel, technology, and system constraint sensitivities

2018 values represent ReEDS model results for the Base Case scenario with Reference electrification.

The results and findings for electricity generation across High electrification versions of the supply-side sensitivity scenarios (Figure 23, page 54) largely follow from the capacity results. For example, we observe an inverse relationship between natural gas-fired and renewable energy generation across the supply-side sensitivities. Natural gas-fired generation in 2050 ranges from 1,020 TWh to 4,100 TWh (brown and tan bars) in 2050, depending on the estimated size of the natural gas resource. VRE generation (and penetration; blue and yellow bars in Figure 23) ranges from 1,650 TWh (under Constant RE Costs) to 5,260 TWh (under Emissions Constraints) in 2050 under High electrification.[68] These ranges are significantly wider than the electrification-driven increase in generation (bottom row of Figure 23), which indicates that the generation mix is more sensitive to supply-side assumptions than it is to electrification. Finally, assumptions about fuel, technology, and system constraints also have a pronounced impact on the cost-competitiveness of coal-fired generation, which ranges from 0 to 800 TWh in 2050 (Figure 23).

Natural gas-fired generation is sensitive to both the estimated size of the natural gas resource and electrification, but there do not appear to be any interactive effects between these two drivers. As a result, natural gas-fired generation under the Larger NG Resource scenario with High electrification can be accurately predicted by summing the isolated effects of (1) a Larger NG Resource and (2) increasing electrification (relative to the Base Case scenario with Reference electrification).[69] By contrast, renewable energy generation results from across the supply-side sensitivity scenarios indicate other features of electrification could increase the efficiency with which they are integrated into the grid. For example, the amount of renewable energy generation under the Lower RE Costs scenario with High electrification (Figure 23, page 54) is 23% greater than what would be expected by simply summing the effects of each individual driver (i.e., Lower RE Costs and High electrification). Because most of the additional renewable energy generation takes the form of VRE sources, this result indicates that the increasing demand, changing load shapes, additional demand-side flexibility, and increasing adoption of flexible natural gas-fired generation and energy storage technologies under High electrification could help facilitate a broader integration of VRE resources on an absolute (terawatt-hour) basis.

The same factors contribute to the relatively low levels of curtailments that are observed across the High electrification versions of the supply-side sensitivity scenarios (Table 11): curtailment rates[70] remain below 7% through 2050 in all scenarios and below 3% in most. The supply-side sensitivities that have the highest levels of VRE generation (Figure 23) involve corresponding increases in absolute curtailments, which approach or exceed 100 TWh in select scenarios in 2050.[71] An interesting exception lies in the Combined scenario, in which curtailments and

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[68] In this scenario, electric sector emissions are subject to an increasingly stringent cap over time, which drives all new incremental demand to be met by zero-emitting sources by 2050.

[69] Natural gas fired generation under the Larger NG Resource scenario with High electrification is roughly equal to the sum of (1) natural gas-fired generation under the Base Case scenario with Reference electrification, (2) the incremental natural gas-fired generation between the Base Case scenarios with Reference and High electrification, and (3) the change in natural gas-fired generation between the Base Case and Larger NG Resource scenarios with Reference electrification.

[70] Curtailment rates are defined as annual curtailment (Table 10) divided by VRE generation (Figure 23).

[71] This magnitude of absolute curtailments could represent an opportunity for new ventures that are designed to turn this otherwise-curtailed electricity into a useful product (e.g., electrolysis-generated hydrogen, power2X technology, and direct air capture); however, we do not model this potential dynamic.

curtailment rates are near zero in 2050 (Table 11), even though VREs provide almost 50% of total generation (Figure 23). This result demonstrates that a flexible power sector—which reflects the increasing displacement of coal-fired generation by natural gas-fired generation—can result in very low curtailment even at VRE penetrations that well exceed current levels.

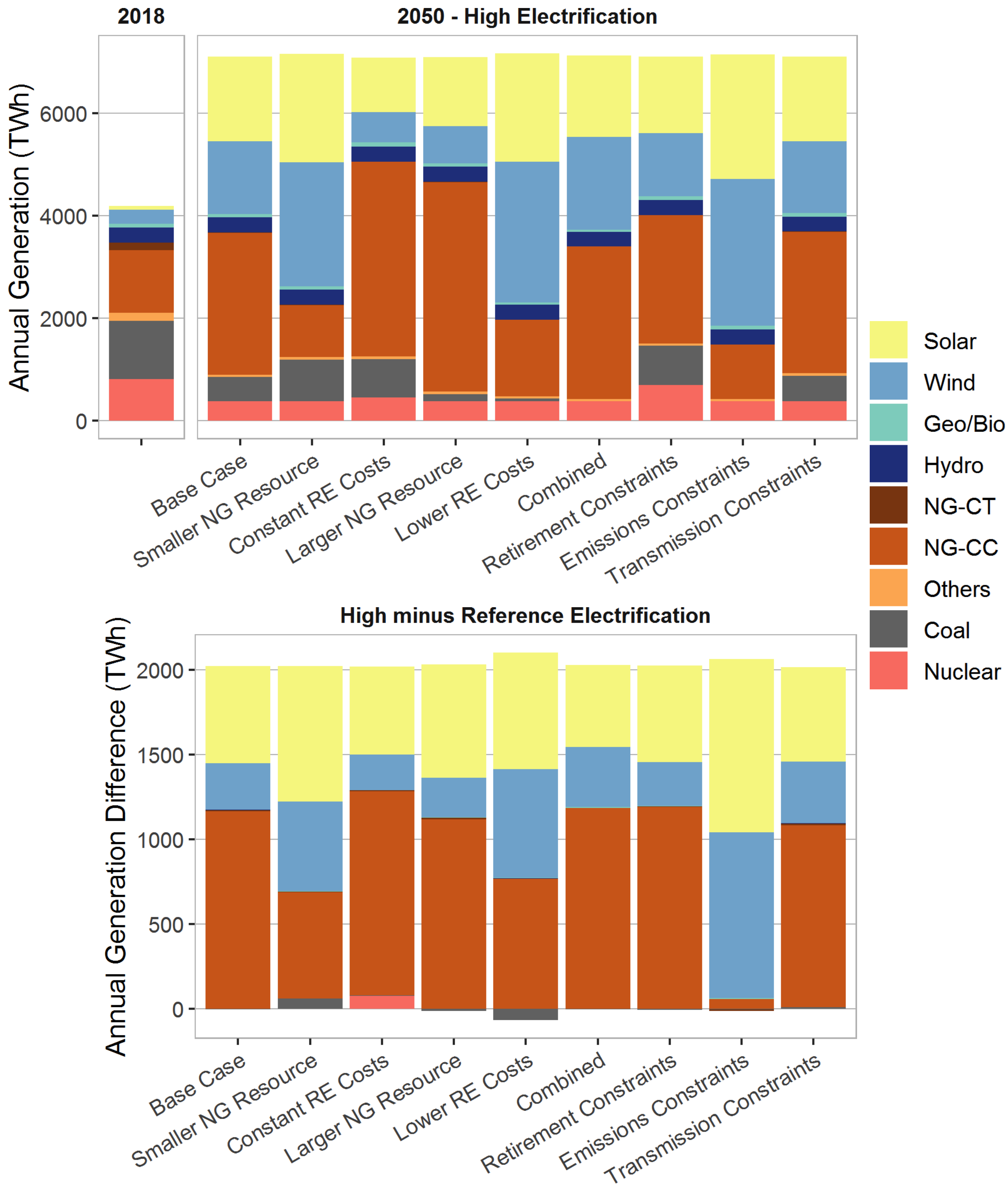

Figure 23. Comparison of 2018 and future generation mixes under High electrification versions of all fuel, technology, and system constraint sensitivities

2018 values represent ReEDS model results for the Base Case scenario with Reference electrification.

Table 11. VRE Utilization Metrics in 2050 across Sensitivity Scenarios and Electrification Levels

Scenario Name	Curtailments (TWh)		Curtailment Rates (%)		Storage Losses (TWh)	
	Reference	High	Reference	High	Reference	High
Base Case	59	54	2.7	1.8	7	12
Lower RE Cost	167	108	4.7	2.2	55	67
Constant RE Cost	5	8	0.5	0.5	3	4
Smaller NG Resource	212	233	6.6	5.2	32	39
Larger NG Resource	10	17	0.9	0.8	3	8
Combined[a]	25	21	1.0	0.6	21	27
Transmission Constraints	56	51	2.6	1.7	6	13
Retirement Constraints	37	38	2.0	1.4	5	12
Emissions Constraints	187	343	5.7	6.5	15	41

[a] The Combined scenario represents Larger NG Resource and Lower RE Cost assumptions simultaneously.

Finally, comparison of the Reference and High electrification results for a given scenario in Table 11 indicates that increasing electrification often leads to a ~1 percentage point decrease in the curtailment rate by 2050. An interesting exception lies in the Lower RE Costs scenario, under which High electrification results in a curtailment rate of just 2.2% in 2050, compared to 4.5% under Reference electrification. This electrification-driven reduction in the 2050 curtailment rate (and the related 35% reduction in *absolute* curtailments; Table 11) demonstrates how the changing load shapes (due to electrification and electrification-induced demand-side flexibility) and increased adoption of low-cost energy storage can facilitate the more-efficient integration of VRE technologies under High electrification.[72] It is worth noting that these curtailment reductions (-59 TWh) are only partially offset by corresponding increase in energy storage losses (+12 TWh; Table 10), most of which arise from battery storage technologies.

4.2 Cost Metrics

Similar to the results presented in the previous sections, evaluation of various electric system cost metrics intuitively reveals that absolute bulk electricity prices and system costs under High electrification depend strongly on fuel, technology, and select system constraint assumptions.

4.2.1 Electricity Prices

Across the full range of High electrification supply-side sensitivities, the modeled bulk electricity prices[73] rise during the 2020s due to a combination of (1) rising natural gas prices

[72] Under the Lower RE Costs scenario with High electrification, energy storage capacity is roughly double that observed under Reference electrification (360 GW compared to 190 GW in 2050). These figures reflect the cumulative capacity of all energy storage technologies modeled in ReEDS, but the incremental growth between Reference and High electrification primarily takes the form of batteries. Note that natural gas-fired generation in this scenario is relatively limited (Figure 23).

[73] Recall that the modeled bulk electricity price is similar to "wholesale" prices in real restructured markets, but it includes the fixed costs (whereas locational marginal prices, in principle, include variable operating costs only).

(in most scenarios) and (2) greater challenges for meeting peak capacity requirements due to retirements (lifetime and utilization-based) and increased demand. By the mid-2030s, bulk electricity prices flatten across all electric system variations, but at different levels depending on the supply-side assumptions. The resulting range of 2050 bulk electricity prices is largely defined by assumptions about the estimated size of the natural gas resource (i.e., natural gas prices) and renewable energy technology costs (Figure 24).

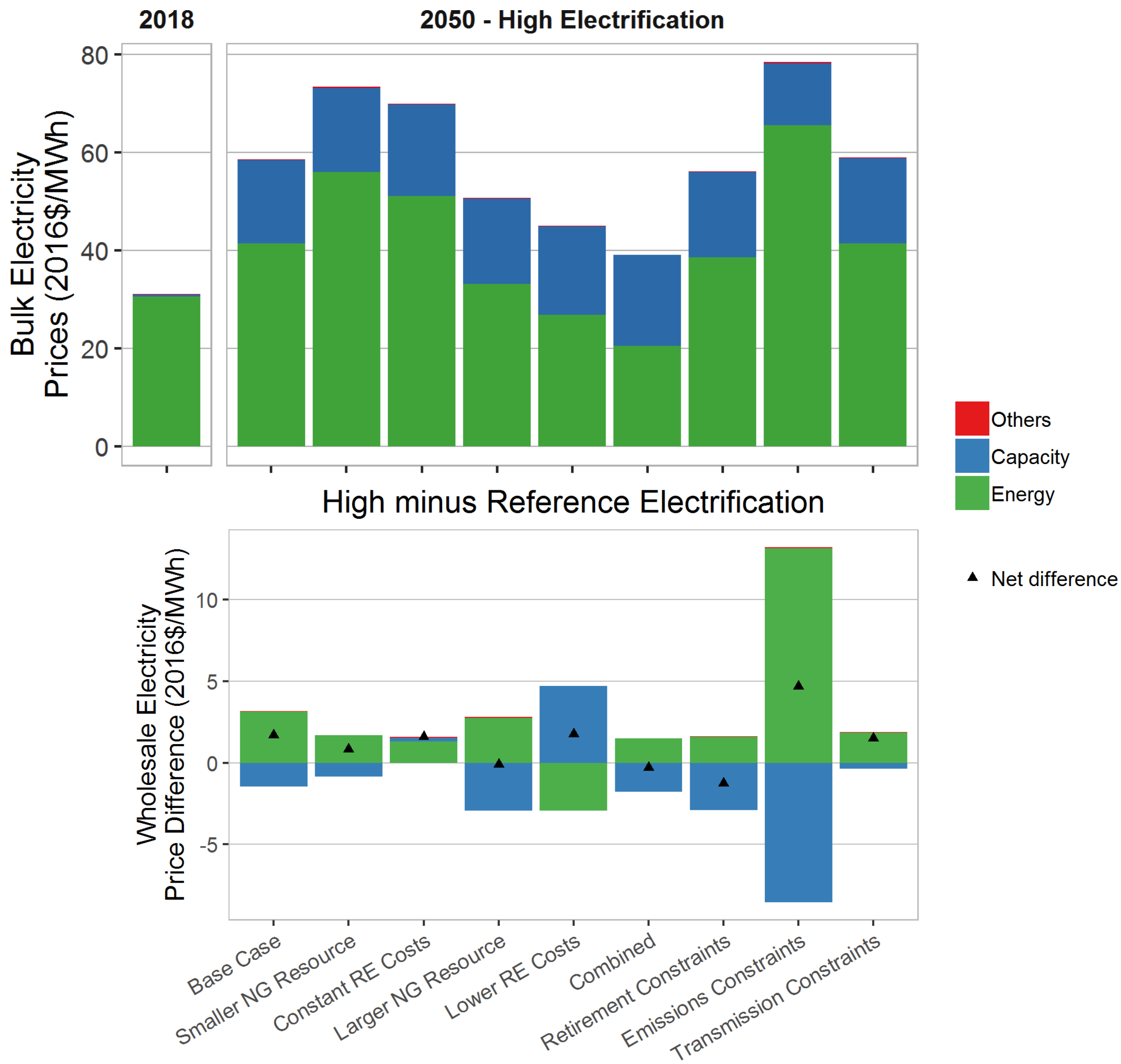

Figure 24. Cumulative (top) and incremental (bottom) effects of High electrification on 2050 bulk electricity prices across all fuel, technology, and system constraint sensitivities

2018 values represent ReEDS model results for the Base Case with Reference electrification.

The model results shown here are more closely related to wholesale electricity prices than to retail electricity prices, but they differ in significant ways from locational marginal prices in restructured markets. The legend indicates the range of cost categories that reflect the marginal prices of meeting different constraints in the model; the Others category includes operating reserve and state policy requirements.

On the lower end of this range, results for the Combined scenario ($39/MWh) reflect only modest increases in bulk electricity prices by 2050 relative to 2018 levels (~$30/MWh based on the ReEDS representation), even though load grows by more than 3,000 TWh (or 80%) over that period. Compared to the Base Case scenario with High electrification (described in Section 2.2.1), the Combined effects of a Larger NG Resource and Lower RE costs drive a 33% reduction in the bulk electricity price in 2050. Inversely, the scenarios representing either a Smaller NG Resource or Constant RE Costs involve national-average bulk electricity prices of around $70/MWh in 2050, which is roughly double that observed under the Combined scenario in the same year (and is similar to the level observed under the Emissions Constraints scenario).

Despite the wide range of absolute values for the bulk electricity price, the net incremental effect of electrification is typically less than $2/MWh in 2050 (bottom row of Figure 24). This suggests that even under pessimistic assumptions about the natural gas resource and renewable energy technology costs, abundant resources are still available, with similar costs, to meet the long-term growth in demand under High electrification. In addition, even for shorter-run decisions (e.g., dispatching existing plants and incremental new capacity additions during a single solve period), the supply curve of resources is shallow, such that the cost to meet the next unit of electricity is not strongly impacted by electrification. Finally, this demonstrates that bulk electricity prices are more sensitive to supply-side sensitivity assumptions than they are to electrification.

4.2.2 System Costs

In contrast to the capacity, generation, and bulk electricity price results explored above, system costs for both the bulk electric and total energy systems are typically *more* sensitive to electrification than they are to fuel, technology, and system constraint assumptions. In particular, the isolated effect of High electrification on bulk electric system costs is found to be a 20%–26% incremental increase across all supply-side sensitivities (Figure 25). The isolated effect of most supply-side assumptions is roughly half as large, such that the variation in bulk electric system costs across High electrification versions of most supply-side sensitivities are ~10%.[74]

The incremental impact of High electrification on *energy* system costs is on the order of $180 billion–$500 billion (black triangles in Figure 25), which is significantly smaller than the corresponding impact on bulk electric system costs in isolation ($520 billion–$860 billion; light and dark blue bars in Figure 25). The smaller-magnitude impact of electrification on energy system costs reflects its larger influence on demand-sector system costs, with incremental reductions in fuel- and O&M-related costs outweighing incremental increases in equipment capital costs. The resulting net system cost savings within the demand sectors serves to offset some of the incremental costs in the bulk electric sector, as depicted in Figure 25.

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[74] The heights of the light and dark blue bars in Figure 25 hint at these two sources and levels of variation, but the percentage changes described above also depend on the absolute bulk electric system costs across supply-side sensitivities (not shown). Comparison of the absolute bulk electric system costs across the Combined scenario with High electrification ($3,050 billion), the Combined scenario with Reference electrification ($2,530 billion), and the Base Case scenario with High electrification ($3,750 billion) reveal that both supply-side and demand-side assumptions drive a ~20% change in bulk electric system costs. The Combined scenario is the only case where the effects of electrification are of similar magnitude to the effects of supply-side assumptions.

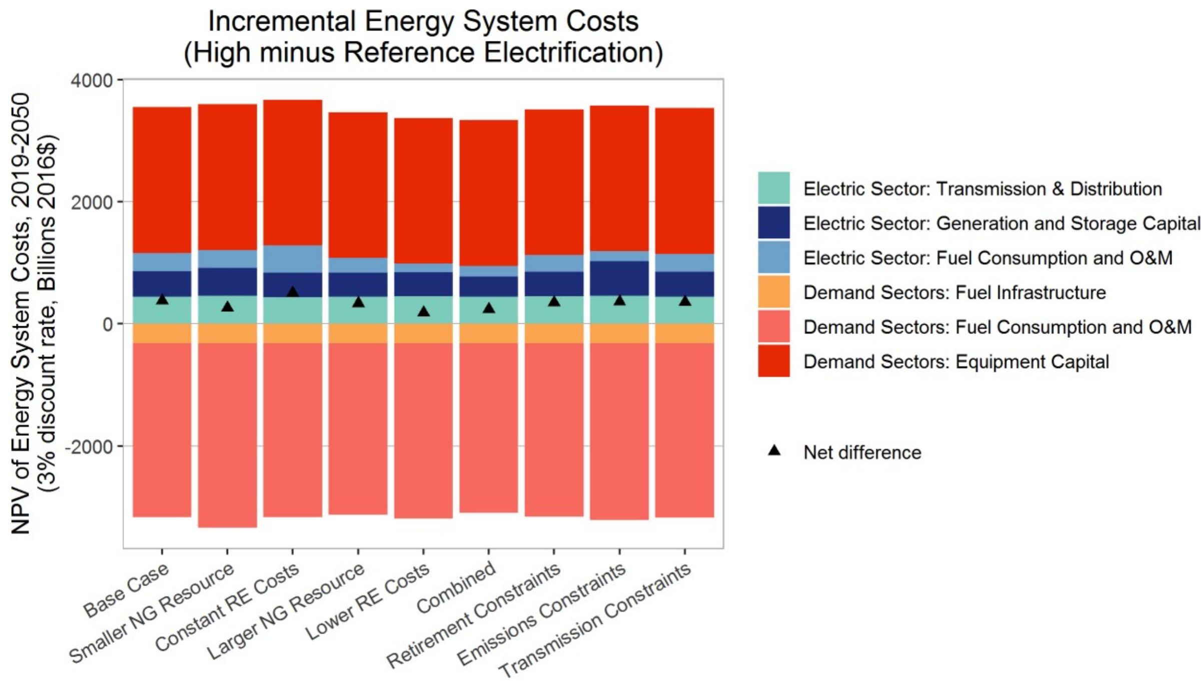

Figure 25. The impacts of High electrification on energy system-wide costs across all electric system variations

Warm shades reflect results from the EnergyPATHWAYS model, which are specific to costs that are borne by demand sectors. The light and dark blue bars reflect results for the bulk electric system, as modeled in ReEDS. The teal bars correspond to the sum of transmission (ReEDS) and distribution (EnergyPATHWAYS) system cost results, for which most costs correspond to the distribution system.

Finally, it is interesting to highlight the extent to which placing economic and noneconomic constraints on bulk electric system evolution could influence the incremental effects of electrification on energy system costs (i.e., the final three bars in Figure 25). The net incremental energy system costs under the three system constraint scenarios ($350 billion–$370 billion) are comparable to those observed under the Base Case ($380 billion) and Larger NG Resource ($340 billion), and they are significantly smaller than under Constant RE Costs ($500 billion). This result indicates that the increasing load associated with High electrification can be accommodated at a similar level of incremental system costs, even under pronounced constraints on the evolution of transmission and generation assets.

Another interesting result lies in the modest system cost impact of transmission expansion across the system constraint scenarios, which define the range of transmission expansion in this analysis (Figure 22). The incremental system costs associated with distribution and transmission expansion are depicted by the teal bar in Figure 25, where most of the incremental costs take the form of investments on the distribution system (which do not vary across the supply-side sensitivities). The similar size of this bar across all scenarios indicates that any system cost increases associated with variations in transmission expansion across supply-side sensitivities (Figure 22) are dwarfed by the other cost categories in Figure 25. This result is most meaningful under the scenarios that represent Emissions and Transmission Constraints, which define the range of transmission expansion in our analysis.

4.3 Energy Consumption

Many of the energy consumption results from across the supply-side sensitivities are similar to those presented for the Base Case in Section 2.3. For example, we find that High electrification drives an increase in electric sector consumption of natural gas across all supply-side sensitivity scenarios (relative to the corresponding Reference electrification scenario). This result indicates that natural gas is relied on to meet some of the incremental electricity demand under increasing levels of electrification, regardless of the fuel, technology, and system constraint assumptions.[75] In addition, it demonstrates that High electrification always drives an increase in the electric sector's share of total energy-sector natural gas consumption.

Despite these similar themes, the electric sector's absolute, and share of, energy-sector natural gas consumption under High electrification are highly uncertain. Relative to 2018 levels, variations in the estimated size of the natural gas resource result in *electric* sector natural gas consumption in 2050 that ranges from a near-tripling (Larger NG Resource) to an absolute *reduction* (Smaller NG Resource) under High electrification (Table 12).[76] When combined with related reductions in direct end-use consumption of natural gas, the latter result indicates that absolute energy-sector natural gas consumption in 2050 could be reduced under High electrification, relative to both 2018 and 2050 Reference electrification levels (Table 12).

Table 12. 2050 Natural Gas Consumption (Quads) and Percentage Changes Over Time

Scenario Definitions		Electric Sector Only, 2050			Energy Sector, 2050	
Fuel Variation[a]	**Electrification Level**	**Absolute (Quads)**	**Percentage Change from 2018[b]**	**Electricity's Share of NG Consumption[c]**	**Absolute (Quads)**	**Percentage Change from 2018[b]**
Larger NG Resource	Reference	20	109%	49%	41	49%
	High	27	189%	66%	42	53%
Default (Base Case)	Reference	11	13%	34%	31	15%
	High	19	95%	57%	33	20%
Smaller NG Resource	Reference	3	-72%	11%	23	-14%
	High	7	-28%	33%	21	-23%

[a] Natural gas resource estimates are based on the AEO2018 (EIA (2018a). The resulting range of results are meant to demonstrate the potential magnitude of impact, but they should not be interpreted as equally likely.
[b] The percentage change between 2018 and 2050 is calculated based on the modeled 2018 results for the Base Case scenario with Reference electrification.
[c] This result reflects electric sector natural gas consumption divided by energy-sector natural gas consumption in 2050. It does not account for non-combustion natural gas consumption or non-energy-sector consumption.

[75] Results in Figure 23 indicate that High electrification drives a modest incremental increase in natural gas-fired generation in 2050 under Emissions Constraints, the majority of which takes the form of NG-CC-CCS generation.
[76] Natural gas consumption trends are intimately related to natural gas prices through elasticity effects (Sun et al. 2020). As expected, fuel and technology assumptions strongly influence the delivered price of natural gas to the electric sector, but they have a more modest impact on the *incremental* impact of electrification. In particular, electrification's influence on the delivered price of natural gas to the power sector is less than 30%, with incremental effects ranging from -\$1.39/MMBtu to +\$0.17/MMBtu in 2050 (relative to the Reference electrification scenarios).

Although this discussion and Table 12 have focused on variations in the estimated size of the natural gas resource, electric and energy-sector natural gas consumption results are similarly sensitive to technology cost and system constraint assumptions. This result is demonstrated in Figure 26, which presents natural gas consumption results from across the full range of High electrification sensitivity scenarios, within the context of primary energy consumption estimates (by fuel type). Overall, the results presented in Figure 26 demonstrate that increasing levels of electrification could reduce total primary energy consumption, primarily due to the higher efficiency of electric end-use equipment (relative to end-use equipment that relies on non-electric fuels). This finding accounts for the increased amount of energy needed to satisfy incremental electricity demand,[77] and the associated conversion losses in that production, which are more than offset by the avoided energy use in demand sectors.

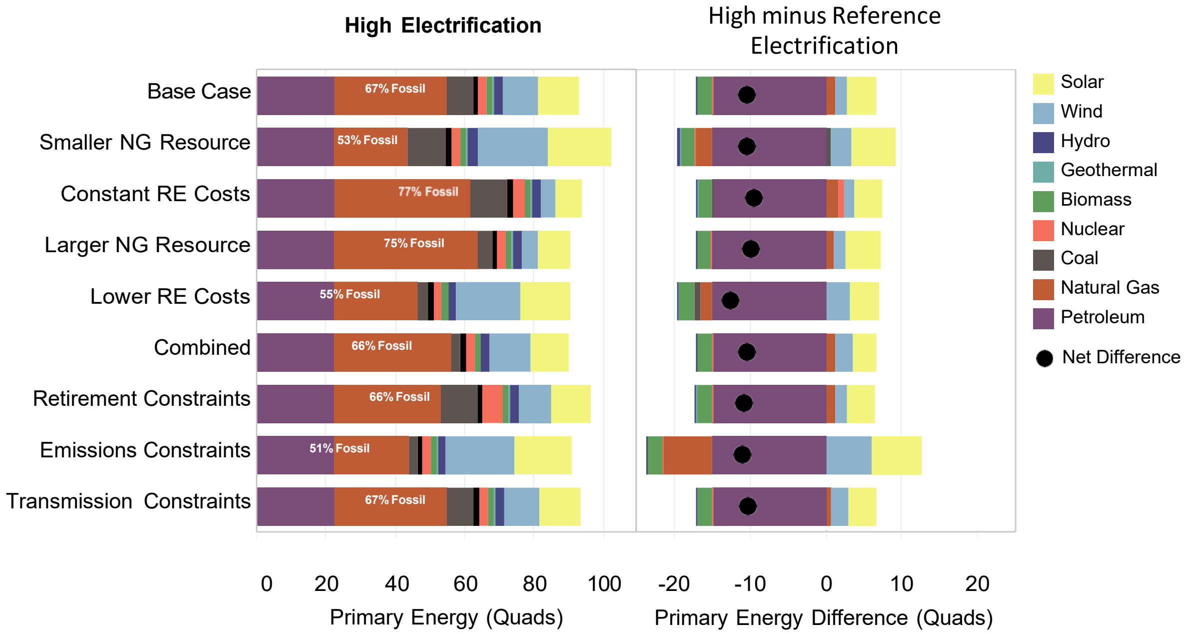

Figure 26. Cumulative (left) and incremental (right) effects of High electrification on 2050 primary energy consumption estimates across all fuel, technology, and system constraint sensitivities

Primary energy consumption estimates for renewable energy are based on a "thermal-equivalent" method (EIA 2012). Dots in the right panel show the net incremental effect of High electrification.

Primary energy consumption estimates range from 90 to 94 quads under High electrification across most supply-side sensitivity scenarios (in 2050). This represents a reduction of 10–13 quads relative to the corresponding Reference electrification scenarios (right panel), which primarily comes from avoided petroleum (and, to a lesser extent, biomass) consumption in the transportation and industrial sectors.[78] Given this pronounced reduction in petroleum use, the

[77] Incremental increases in primary energy consumption within the electric sector reflect both the increase in demand and the use of the thermal-equivalent method of calculating primary energy (see Appendix C for details). In this method, the conversion from renewable *electricity* to primary energy depends on the average energy efficiency of the entire electricity generation mix. Other methodologies for calculating primary energy could result in different conclusions for electrification's effect on electric sector primary energy consumption.

[78] The one exception to this finding is the Smaller NG resource scenario, in which 2050 primary energy is estimated to be 102 quads. Note that this 2050 primary energy consumption is 5 quads higher than estimated consumption in

2018 while the amount of services, population, and GDP grows as estimated by the underlying AEO trajectory.

ultimate mix of primary energy consumption—and the share of primary energy that is sourced from fossil fuels—depends strongly on the power generation mix. For example, the share of primary energy consumption that is derived from fossil fuels in 2050 ranges from 51% to 77%, depending on future fuel, technology, and system constraint factors.

4.4 Air Emissions

This final section of results presents the air emissions impacts of electrification across all electric system variations. Direct emissions from end-use sectors are only sensitive to the assumed level of electrification based on our scenario framework (i.e., they do not depend on supply-side assumptions); therefore, annual end-use emissions for a given electrification level are identical to those presented in Section 2.4. In turn, all changes to energy emissions across electric system variations are due to changes in absolute electric sector emissions. Recall that these scenarios assume full implementation of current air pollution regulations to 2050, with no additional regulations put into place; more-stringent (or relaxed) regulations on energy-sector air emissions would tend to reduce (enhance) the incremental effects of electrification on air emissions.

High electrification drives a reduction in absolute energy-sector CO_2 emissions over time, regardless of the fuel, technology, and system constraint assumptions (left panel of Figure 27). However, varying these assumptions results in a wide range of energy-sector emissions results that depends most strongly on the future cost and performance of renewable energy technologies.[79] The upper-bound result in Figure 27 reflects Constant RE Costs, in which electric sector emissions (not shown) increase steadily over time, eventually growing to 35% above 2018 levels in 2050 under High electrification. Therefore, the absolute *reduction* in energy-sector CO_2 emissions—which fall to 17% below 2018 levels in 2050 (dotted blue line in Figure 27)—speaks to the magnitude of reductions in direct end-use emissions under High electrification.

Inversely, energy CO_2 emissions reductions under the Lower RE Costs and Combined scenarios reflect declining emissions in both the electric and end-use sectors. These fuel and technology assumptions result in the most rapid emissions reductions (i.e., the steepest slopes in Figure 27) during the 2020s, which reflects two related factors: (1) the accelerated displacement of higher-emitting sources by low-cost renewable energy and/or natural gas generation and (2) incremental load under increasing levels of electrification is primarily being met by zero-emitting technologies. For the Lower RE Costs scenario, these factors continue throughout the analysis period, such that electric sector emissions fall to 0.58 billion metric tons in 2050; when combined with the 2.1 billion metric tons of end-use emissions,[80] energy-sector emissions in 2050 are 47% below 2018 levels.[81]

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[79] For the supply-side sensitivity scenarios that involve similar absolute energy CO_2 emissions as in the Base Case, the presentation and findings in Section 2.4 directly apply.

[80] This level of direct emissions from end-use sectors is higher than those in previous studies that were motivated by economy-wide emissions reductions (White House 2016; Williams et al. 2014; Clarke et al. 2014). One reason for this difference is the scope of the present analysis, which is limited to direct electrification and therefore does not consider other emissions-reducing strategies.

[81] The level of 2050 energy sector CO_2 emissions are nearly identical in the Lower RE Costs and Emissions Constraints scenarios; however, accounting for their different trajectories, the Lower RE Costs scenario actually results in greater emissions reductions when integrating over the entire analysis period.

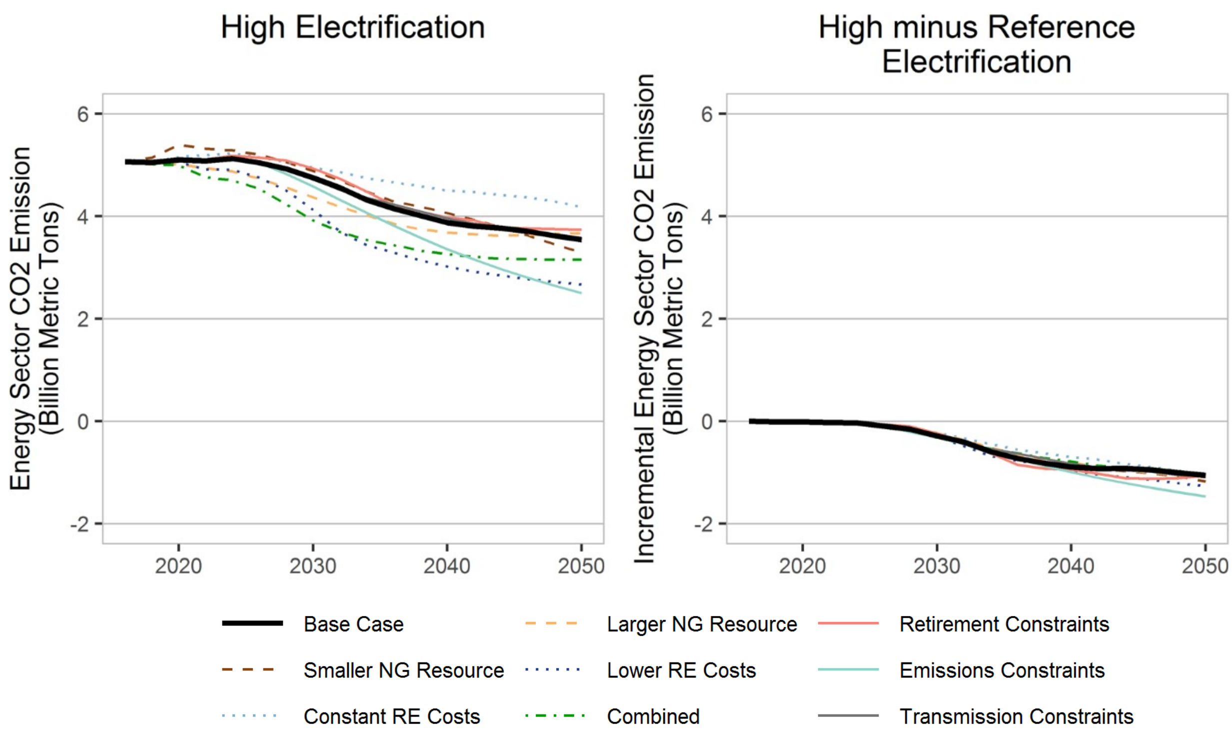

Figure 27. Cumulative (left) and incremental (right) effects of High electrification on direct CO_2 emissions from the energy sector across all fuel, technology, and system constraint sensitivities

Demand and direct emissions from end-use sectors only vary with the assumed level of electrification, so differences across scenarios reflect changes in electric sector emission rates.

Finally, we similarly find that the High electrification versions of each supply-side sensitivity result in declining energy-sector SO_2 and NOx emissions over time, regardless of the fuel, technology, and system constraint assumptions. These reductions reflect, in part, the declining emissions rates associated with both electricity generation (primarily due to the displacement of higher-emitting generation units) and end-use equipment (primarily due to technology improvements for on-road vehicles). In particular, electric sector NOx and SO_2 emissions rates decline over time across all supply-side sensitivities, but the pace and extent of reduction intuitively depend on the generation mix (e.g., Figure 23). For the scenarios with the largest shares of coal-fired generation (Constant RE Costs, Smaller NG Resource, and Retirement Constraints), combining their emissions factors with the increasing demand under High electrification results in flat trajectories for electric sector NOx and SO_2 emissions over time. Inversely, scenarios with the smallest shares of coal-fired generation (Lower RE Costs, Combined, and Emissions Constraints) involve a near-complete elimination of electric sector NOx and SO_2 emissions by 2050.[82]

Within the context of these reductions in electric sector emissions over time, the isolated effect of electrification is typically a modest incremental increase in electric sector NOx and SO_2 emissions,

[82] The Larger NG Resource scenario also involves near-zero generation from coal-fired power plants in 2050, which similarly drives the near-complete elimination of SO_2 emissions. However, the increasing role of natural gas-fired generation in the scenario results in more-modest reductions in electric sector NOx emissions.

relative to the corresponding Reference electrification scenario. The one exception occurs with the Lower RE Costs scenario, in which High electrification also drives an incremental *reduction* in electric sector NOx and SO_2 emissions. This result demonstrates that in addition to all incremental load being met by zero-emitting sources in that scenario, related dynamics within the electric sector also lead to the displacement of additional higher emitting sources compared to the Reference electrification version of the scenario.

Accounting for the pronounced reductions in direct NOx and SO_2 emissions from demand sectors (Figure 16), the net effect of electrification is a reduction in energy NOx and SO_2 emissions across all supply-side sensitivities. In particular, High electrification drives a 50%–60% reduction in energy-sector NOx emissions by 2050 (relative to 2018 levels), where the range reflects different fuel, technology, and system constraint assumptions. For energy SO_2 emissions, the net effect of High electrification ranges from a 5% to as 34% reduction in 2050 (relative to 2018 levels), where the wider range reflects the electric sector's larger share of energy SO_2 emissions.

5 Conclusions

This report concludes by presenting a list of key findings and potential future research directions that were informed by this analysis.

5.1 Key Findings

The five key findings of our analysis are as follows:

1. **Electrification drives the sustained deployment of renewable energy and natural gas generators in *all* regions and, in turn, increases generation from these sources; the corresponding expansion of long-distance transmission capacity is correlated with growth in renewable energy sources**.

Reliably serving electricity demands under the High electrification scenarios requires a more-than-doubling of installed capacity by 2050, relative to 2018 levels. In our scenarios, substantial local resources are leveraged, such that this approximate doubling of generation capacity occurs in all regions of the country. New natural gas and renewable energy projects are relied upon to meet growing electricity demand associated with widespread electrification. This result follows from the fact that these technologies are among the least-cost options—based on the assumptions used—for new generation capacity. In the long run, new generation capacity is needed for all electrification scenarios to replace retiring generators and growing load, but electrification-driven demand growth amplifies these needs and changes the competitiveness of natural gas and renewable energy technologies in two subtle ways.

First, *electrification-driven reductions in end-use natural gas consumption, and the resulting downward pressure on natural gas prices increases the competitiveness of natural gas-fired electricity generation, in the absence of new policies*. Under default assumptions (i.e., the colored bars from Figure 28, page 65), average annual capacity additions of natural gas-fired technologies exceed 30 GW during the two latest decades shown. *The extent to which natural gas-fired generation could be relied upon to meet growing electricity demand also depends strongly on physical and market forces that introduce significant uncertainty in future natural gas prices*. This result is demonstrated by the vertical lines in Figure 28, which present estimated annual capacity additions across the full range of High electrification scenarios.

Second, *the growing deployment of renewable energy technologies is expected to continue and is amplified by electrification*. Under default assumptions (i.e., the colored bars from Figure 28), annual solar and wind capacity additions exceed 30 GW and 20 GW, respectively, during the 2040s, with even greater deployment rates during the 2030s for solar technologies. Moreover, *the ultimate pace and extent of renewable energy deployment depends strongly on future market, technology, and policy conditions, which dictate the relative competitiveness of new natural gas versus renewable energy technologies*. In particular, considering the full range of scenarios (vertical lines from Figure 28), annual deployment rates range from less than 10 GW to *potentially unprecedented levels*. This electrification-driven increase in renewable energy deployment is partially driven not only by the increase in electricity demand but also by *several unique aspects of electrification—including how it changes load shapes, drives the increased deployment of flexible generation technologies, and could potentially expand demand-side flexibility*. As a result of all these factors, *we find that electrification could lead to a more conducive environment for integrating variable renewable energy technologies*.

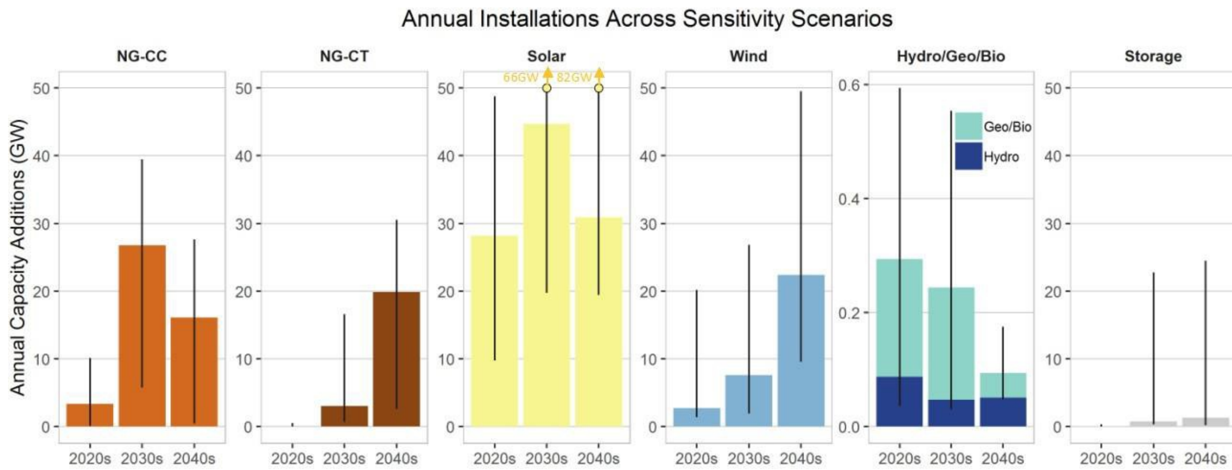

Figure 28. National annual average capacity additions by technology across the High electrification scenarios

Colored bars reflect results from the Base Case scenario, while vertical bars reflect the range across the sensitivity scenarios. Note the different vertical scales.

Although growth in both natural gas and renewable energy capacity occurs over time, these two sources also compete to supply electricity to new demands from electrification. In particular, pessimistic assumptions about renewable energy technology advancement lead to the lower-bound results for solar and wind deployment, and to the upper-bound results for the deployment of natural gas-fired technologies in Figure 28. Conversely, optimistic assumptions about renewable energy technology advancement results in relatively modest annual capacity additions of natural gas capacity through 2050, and to the accelerated and expanded deployment of both renewable energy and storage technologies. In particular, *energy storage is used to meet changes from electrification, including to meet greater planning reserve requirements driven by higher demand peaks*. Considering the full range of results presented in the right-most panel of Figure 28, the magnitude of electrification-driven storage deployment is sensitive to its future cost and renewable energy deployment, given the flexibility that storage can provide to support the integration of variable renewables.

New transmission infrastructure is also expected with electrification, but *local resources are increasingly relied upon to meet electrification-driven load growth, which mitigates the influence of electrification on the need for additional long-distance, inter-regional transmission expansion. However, the magnitude of short transmission segments to interconnect new renewable energy generators scales with electrification, and total transmission capacity expansion scales with renewable energy deployment levels*. Therefore, the amount of future transmission is actually more sensitive to supply-side assumptions than it is to electrification. For example, scenarios that lie toward the top of the vertical lines for wind and solar in Figure 28 involve total transmission capacity expansion of 50%–75%, compared to the system in 2018. At the same time, select scenarios reveal that the ~80% increase in electricity consumption that occurs under High electrification (between 2018 and 2050) can be accommodated with negligible growth in long-distance transmission, and 18%–28% growth in total transmission by 2050 (relative to 2018 levels). The latter scenarios reflect a range of VRE penetration levels (29%–42% in 2050), and they demonstrate the abundance of local resources that could be relied on to meet increasing demand under widespread electrification.

More research is needed to understand the effects of other factors that are not fully considered by our analysis but could have a sizable impact on the magnitude, makeup, and feasibility of the electrification-driven infrastructure development in the power system. For example, given the magnitude of infrastructure development needed to meet electrification-driven load growth, there is the potential for new or expanded challenges related to materials availability, supply chains, and siting and permitting. In addition, more research is needed to evaluate the interactions and trade-offs between transmission, storage, and flexible load and how electrification impacts these interactions. Finally, more research is needed to assess the economic and noneconomic trade-offs between local and remote resources. Ultimately, whether electrification occurs, to what extent, and how electricity systems will evolve to meet future needs will be strongly influenced by local factors and local constituents.

2. **Electrification inherently increases the reliance of demand sectors on electricity, and it could offer enhanced opportunities for more-active participation from flexible loads in the planning and operations of the electricity system.**

Electrification could open opportunities for increased flexibility from all demand sectors (buildings, transportation, and industry), with the most pronounced effects arising from flexible electric vehicle charging. From the perspective of the electric system, *flexible loads can partially mitigate the power sector infrastructure needs and associated costs from electrification, particularly by serving as a resource to meet peak demands and planning reserves.* In particular, increasing the amount of flexible load (e.g., from Base to Enhanced demand-side flexibility levels) results in a shifting of electricity demand from the afternoon and evening time-slices into the overnight and morning hours, which reduces peak demand. In turn, the modeled increase in demand-side flexibility reduces the amount of installed capacity in 2050 by 100 GW (difference between the orange bars in Figure 29), and the *incremental* capacity needs of meeting High electrification by 60 GW (difference between the grey bars in Figure 29). Inversely, *without additional demand-side flexibility, high demand peaks from electrification could lead to increased requirements for infrastructure development and greater reliance on other supply-side sources for flexibility.*

In addition, *flexible loads could support more cost-efficient bulk power system operations,* which take the form of an increase in the utilization of generation assets. *As one example, demand-side flexibility results in reduced curtailments, which indicates that flexible load could support grid integration of variable renewable energy resources*, even in the context of reductions in energy storage capacity. In addition, despite the declining deployment of natural gas capacity with increasing levels of demand-side flexibility, the modeled generation from natural gas-fired power plants is largely insensitive to the assumed level of electrification; this result indicates a flexibility-driven increase in the capacity factors of natural gas-fired power plants, and a similar trend is also observed for the utilization of existing coal-fired power plants.

Overall, demand-side flexibility provides value to the system by (1) reducing total bulk electric system costs in all scenarios (independent of electrification level) and (2) mitigating some of the incremental capital and operational expenditures with increasing electrification (Figure 29). When these system cost savings are levelized by the corresponding amount of flexible load, we find that there may be diminishing savings with increasing demand-side flexibility. However, given the wide range of flexibility assumptions explored, the rate of reduction is likely modest.

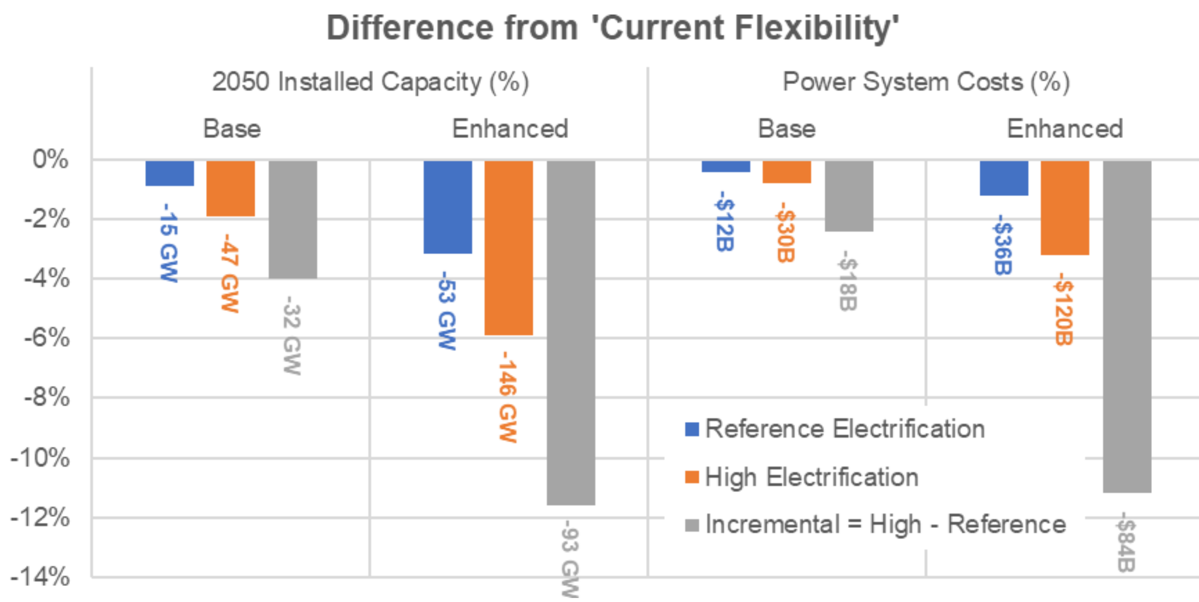

Figure 29. Increasing demand-side flexibility reduces the need for new capacity and, in turn, lowers the absolute and incremental level of expenditures on the bulk electric system

It is unclear whether the range of demand-side flexibility evaluated here captures the full set of possibilities for every subsector. Additional research is also needed to understand the unique roles of and competition between different sources of flexibility (e.g., demand-side flexibility, energy storage options with shorter to seasonal duration, thermal energy storage, and institutional practices that increase system flexibility), which may also depend on the overall generation mixes. Planned future work for the EFS will begin to explore the operational factors associated with electrification and demand-side flexibility in detail, via production-cost modeling. However, more-detailed studies are required to develop strategies to overcome technical and institutional barriers to enable demand-side flexibility and assess market mechanisms to effectively incentivize and compensate consumers’ participation in flexibility programs.

3. There are abundant resources in the United States with similar costs to meet potential electrification-driven growth in electricity demand.

Figure 30 shows how sensitive power system costs are to the full set of demand- and supply-side variations modeled with both Reference and High electrification. Not surprisingly, system costs are sensitive to future market, technology, and system constraint assumptions, irrespective of electrification level. However, the figure indicates that total bulk electric system costs are much more sensitive to variations in supply-side input assumptions (orange circles) than they are to future electric end-use technology advancements and the amount of flexible load (green circles). This trend is apparent for both electrification levels in the figure, but bulk electric system costs under High electrification are more sensitive to these factors in absolute terms.[83]

[83] In percentage terms, the variations in system costs from the supply-side sensitivities are similar with Reference and High electrification, as the impacts of fuel and technology cost largely scale with power system size. By

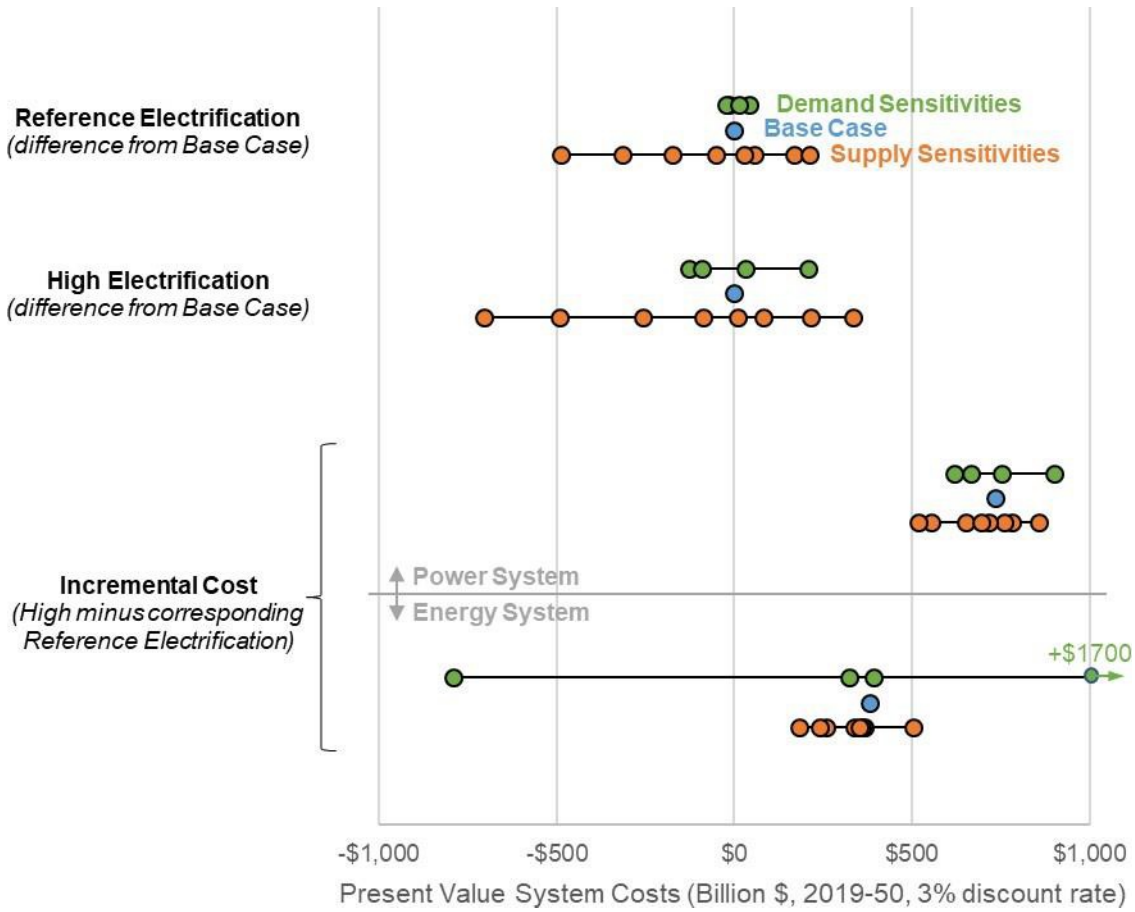

Figure 30. Electric and energy-sector system costs across all demand-side and supply-side sensitivity scenarios

The top half of the figure shows the variation in bulk electric system costs relative to Base Case conditions from both demand-side (spanning the range of end-use technology and demand-side flexibility assumptions) and supply-side (spanning the range of NG resource, RE cost, and system constraint) sensitivities. The bottom half of the figure shows incremental system costs (difference between High and corresponding Reference electrification versions of each scenario) in the bulk electric and broader energy systems for the same set of scenarios.

The bottom half of Figure 30 shows how sensitive the *incremental* change (High minus Reference) in bulk electric system costs is to the same variations. Across all variations, we estimate that High electrification results in a 19%–29% increase in the present value of bulk electric system costs from 2019 to 2050 at a 3% discount rate, relative to the corresponding Reference electrification scenarios. This result demonstrates that *while the United States has sufficient resources to meet future electrification needs, the increased generation and transmission capacity required to meet growing load under widespread electrification intuitively requires an increase in power sector expenditures across all scenarios explored*. Unlike the results from the top of Figure 30, however, incremental electric system costs are found to be

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contrast, variations from end-use demand technologies and demand-side flexibility are greater under High electrification, because of both (1) the efficiencies of electric vehicles and heat pumps having a larger impact under High electrification and (2) the greater potential for flexible load with increasing levels of electrification.

approximately as sensitive to demand-side and supply-side variations. This means that although the total cost of building and operating the power system will depend strongly on market factors such as future fuel prices and generation technology improvements, the *incremental* cost from electrification is less sensitive to these factors, due to the availability of abundant natural gas and low-cost renewable energy resources.

Because bulk electric system costs scale with system size, a comparison of incremental costs per unit of electricity consumed under various levels of demand growth informs the cost-effectiveness of the underlying generation resource. Doing so for both the Medium and High electrification (relative to the Reference electrification, all using Base Case assumptions) reveals that *electrification's effect on the cost per unit of electricity consumed is modest* ($40–46/MWh). Similarly, *electrification's effect on bulk electricity prices is modest, because incremental demands are likely met by low-cost natural gas and renewable energy resources.* In particular, the incremental effect of High electrification on 2050 bulk electricity prices is less than $5/MWh in all scenarios explored (relative to the corresponding Reference electrification scenario). In some cases, High electrification is actually found to drive a *reduction* in the modeled 2050 bulk electricity prices, relative to both the corresponding Reference electrification and 2018 levels. Finally, *the effect of electrification on total **energy** system costs is more complex*, as will be explored in the next finding.

4. **Considering the entire energy sector, the net system cost impact of electrification depends most significantly on future advancements in the cost and efficiency of electric end-use technologies.**

Electrification results in an increase in electric sector system costs and higher capital expenditures for demand-side equipment. However, these system cost increases are partially or entirely offset by fuel and operational savings in the buildings, transportation and industry demand sectors. This result is shown in the bottom of Figure 30, where incremental energy system costs are lower than incremental power system costs in all but one scenario. For example, in the Base Case (blue circle), the net present value of incremental bulk electric system costs is estimated to be $730 billion, but incremental *energy* system costs are around half that ($380 billion).

Electrification can result in net energy system savings when it (1) occurs together with more rapid advancements in the cost and efficiency of end-use electric technologies or (2) extends primarily to more cost-effective technologies and circumstances. The former result is demonstrated by the far-left green circles in the bottom half of Figure 30, which indicate that High electrification *reduces* energy system costs by nearly $800 billion (relative to the corresponding Reference electrification results). These savings are primarily derived from avoided fuel and O&M expenditures in demand sectors, which are more than enough to compensate for the incremental increases in equipment cost and power sector infrastructure expenditures (which are also more modest than under default assumptions). Energy system savings are also observed under Medium electrification (not shown in Figure 30), which demonstrates the benefits associated with electrifying the sub-sectors with potentially lower barriers to electrification.

Conversely, when end-use electric technology advancements are limited, electrification results in net energy system cost increases due to several compounding factors: (1) higher capital *expenditures are needed for demand sector equipment, (2) direct operational savings of such equipment are more-limited, and (3) greater electric sector expenditures are required if efficiency improvements are slow to materialize.* It is important to note that these system cost estimations exclude potential monetary impacts associated with energy security, environmental damages, health impacts, and other externalities. In addition, the cost metrics used do not reveal distributional impacts. Further analysis is needed to assess the economic impacts by region, demography, and the wide range of stakeholders who would be affected by electrification.

5. **Electrification reduces direct energy consumption and emissions in the demand sectors and shifts them into the power sector, the net effect of which is energy system-wide reductions in both.**

Because of the energy efficient nature of electric end-use technologies, direct final energy use is lower with widespread electrification. Moreover, even when accounting for the losses associated with the conversion of fuels to electricity as well as transmission and distribution losses, electrification reduces total primary energy consumption. In particular, primary energy consumption estimates for 2050 typically range from 90 to 94 quads under High electrification, which represents an absolute reduction relative to 2018 estimates. Comparison against the corresponding scenarios with Reference electrification reveals primary energy savings of about 10–13 quads (Figure 31, page 71). Both of these comparisons demonstrate that the adoption of electric end-use equipment and their higher energy-efficiency (relative to conventional end-use equipment) would likely result in a decline in energy consumption—despite the increased energy used for electricity generation (and the associated losses).

Electrification-driven reductions in energy consumption primarily arise from avoided fossil fuel consumption in the demand sectors, most prominently avoided petroleum consumption from the transportation sector. By contrast, *the impact of electrification on total energy sector natural gas consumption is muted because reductions in end-use natural gas consumption are typically offset by increases in natural gas used for power generation.* Instead, demand for natural gas is much more sensitive to the size of the natural gas resource (which influences natural gas prices), such that estimates for energy sector-wide natural gas consumption under High electrification range from a ~50% increase to absolute reductions in 2050 (relative to 2018 levels).

Finally, similar and related themes are revealed in the modeled electric and energy system air emissions results for carbon dioxide, sulfur dioxide, and nitrogen oxides (CO_2, SO_2, and NO_X). In particular, *electrification reduces direct CO_2, SO_2, and NO_X emissions from the demand sectors in total across the contiguous United States,* relative to both Reference electrification (in all years) and 2018 levels (Figure 31). Following from the energy consumption results above, the avoided consumption of petroleum in vehicles drives the largest-magnitude reductions in both NO_X and CO_2 emissions, which reflects both the (1) aggressive vehicle electrification assumptions and (2) on-road vehicles' share of these emissions. Electrification-driven reductions in SO_2 emissions are estimated to be more modest, and they primarily take the form of avoided industrial emissions. Residential and commercial buildings contribute to reductions in all three emissions types, primarily due to the displaced consumption of natural gas and heating oil as space and water heating are increasingly electrified (Figure 31).

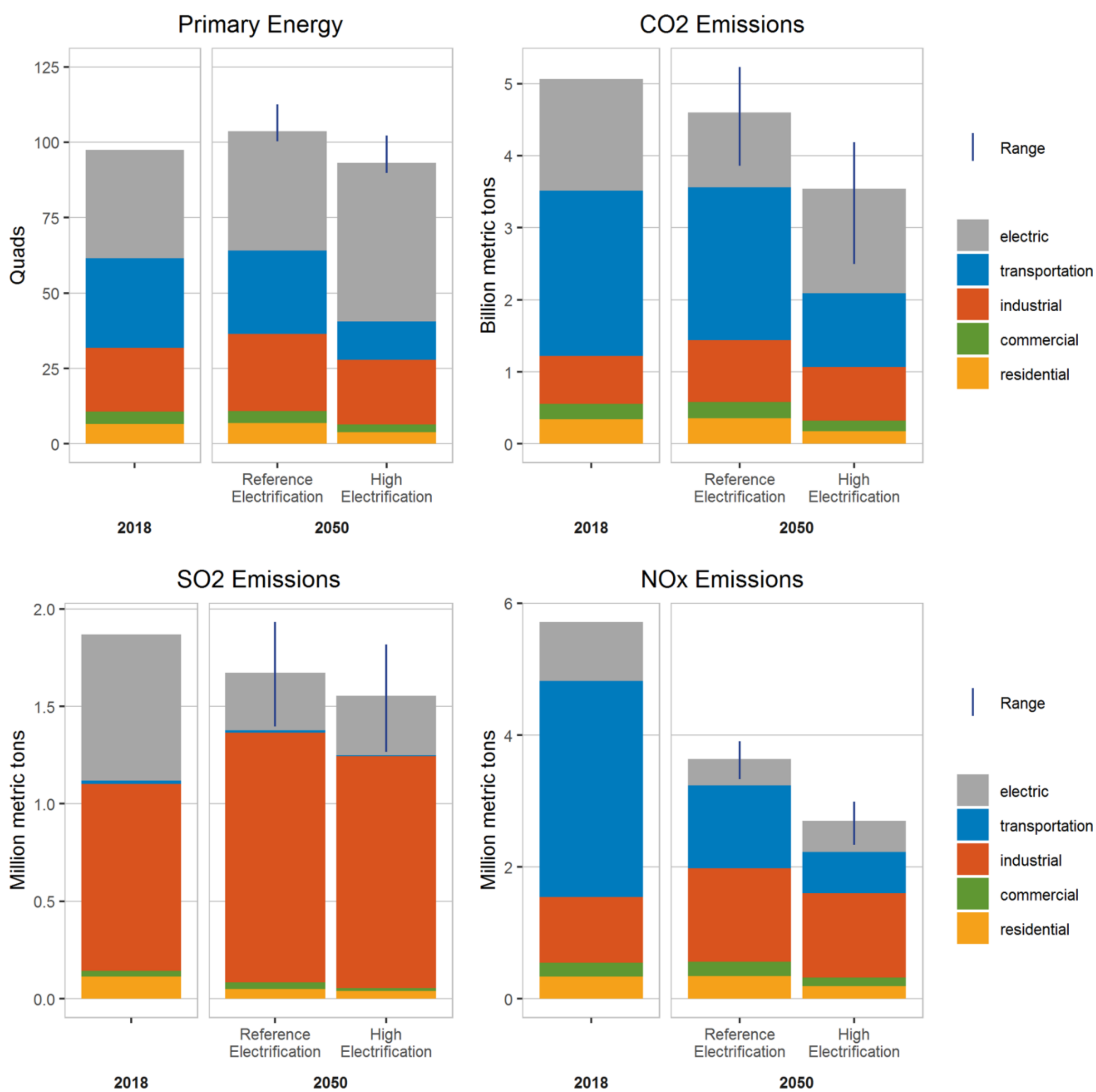

Figure 31. Primary energy and air emissions results (by sector) across the full suite of scenarios

2018 values represent model results for the Base Case scenario with Reference electrification.

For the 2050 results, colored bars indicate results from the Base Case scenarios with Moderate electric end-use technology advancement. The vertical blue line presents the range of results across all electric end-use technology advancement, demand-side flexibility, and supply-side sensitivity scenarios. In general, the position of a given scenario along the vertical range will be similar for both Reference and High electrification results.

On the power sector side, we find that *the emissions **intensities** of carbon dioxide, sulfur dioxide, and nitrogen oxides (CO_2, SO_2, and NO_X) associated with electricity generation decline over time and with increasing electrification, as new demand is met from lower-emitting generation sources*. When coupled with electrification-driven load growth, the incremental effect of electrification is a modest increase in absolute electric sector emissions over Reference electrification levels. However, the magnitude of this incremental increase is modest compared to the previously described reductions in absolute demand-sector emissions. In other words, while *some of these avoided demand-sector emissions are shifted to the power sector, the net effect of electrification is an overall reduction in energy sector-wide air emissions* across all scenarios with widespread electrification, relative to both 2018 and Reference electrification levels (Figure 31).

Despite this systematic result, *electricity emissions intensities are sensitive to the future competitiveness of low-emissions generators and power system constraints*. As a result, a wide range of electric and, in turn, energy sector emissions trajectories are observed across the High electrification scenarios. Variations in natural gas prices and renewable energy technology costs largely define this range in 2050 (Figure 31), which include a 50%–60% reduction in energy-sector NOx emissions relative to 2018 levels, a 5%–34% reduction in energy-sector SO_2 emissions relative to 2018 levels, and a 17%–47% reduction in CO_2 emissions relative to 2018 levels under High electrification.[84]

The emissions analysis presented here is narrow in scope, and further research is needed to explore the implications of these findings. First, emission estimates are on a direct emissions basis only, so emissions during other life-cycle phases of the end-use; for example, battery manufacturing and recycling (Pellow et al. 2019) and fuel (Brinkman et al. 2005) or power generation (IPCC 2014; Masanet et al. 2013) technologies are not included. In addition, the emissions estimates reflect only combustion emissions from the energy sector, so they do not include process-based emissions or emissions from non-energy sectors (e.g., agriculture or wildfires). Third, emissions are reported in physical quantities and at an annual level only; estimating their economic impacts (in monetary terms) would require estimates of the environmental and health outcomes associated with various levels and timing of emissions (e.g., IWG 2016, Siler-Evans 2013, and others). Health damages of SO_2, NO_x, and other criteria pollutants are also highly localized (from urban areas down to indoor facilities) and vary by season; they also require high-resolution pollutant transport and chemical transport modeling to accurately assess.

5.2 Future Research

Beyond the future research directions identified within each of the key findings above, we conclude this report by identifying suggested future research topics that would improve the current understanding of the potential impacts of widespread electrification:

- **Electrification's impact on the financial attractiveness of distributed energy resources (DERs) and energy efficiency:** The impacts of electrification—on electricity consumption, demand-side flexibility, and electricity prices, for example—could influence the financial attractiveness of DERs. However, the magnitude and direction of their combined and interactive effects on DER adoption are currently not well understood. Future research is needed to understand the extent to which it is cost-

[84] These ranges are driven by the variations in the electric sector, as we only assessed emissions impacts from a single set of emissions rates for non-electric technologies. Technology change for non-electric technologies could also impact future emissions and the magnitude of electrification's impact on emissions.

effective to accommodate changing demand under widespread electrification with DERs, and the corresponding influence on the required buildout of the power system. Similarly, more research is needed to understand the interactions between electrification and utility-scale programs (and policies) for end-use efficiency.

- **Distribution system impacts:** The detailed modeling presented in this report focused on transmission-level assets, including generation, storage, and long-distance and spur line transmission capacity. However, electrification would likely have implications for the electricity distribution system. Additional research is needed to better understand the impacts of co-deployment of distributed generation, smart controls, and upgrades of utility grid equipment, as well as the costs associated with each of these strategies on the electric distribution system.
- **Utility business model impacts:** For some power system stakeholders and observers, interest in electrification is motivated by its potential impact on utility business models and revenues (Weiss et al. 2017; EEI 2014). On the most basic level, electrification is expected to raise sales volumes for electric utilities and, thereby, increase revenues from these electricity sales.[85] However, the full set of impacts is much more complex, and it would vary across entities and regions and would include demand-side flexibility incentives and/or new players (e.g., load aggregators). For example, electrification may impact distribution companies, transmission companies, generation companies, and merchant actors differently depending on their specific circumstances.
- **Implications for the manufacturing and natural gas sectors:** Detailed modeling is needed to evaluate whether the existing natural gas pipeline network is sufficient for accommodating the modeled redistribution of natural gas across sectors and regions. Moreover, additional research is needed to understand and quantify how electrification could impact the business models of liquid fuels producers and natural gas distribution companies. Finally, future work is needed to understand the supply-chain implications of the wide range of deployment rates for natural gas-fired and renewable energy capacities.

[85] For combined gas and electric utilities, the situation is more complex, as electrification may increase revenues on one part of the business (e.g., electricity) at the expense, at least in part, of the other (e.g., natural gas).

Appendix A. Caveats and Limitations

Modeling the future electricity system is inherently challenging due to (1) multiple dynamics that affect the evolution of a large complex system and (2) the inherent limitations in any long-term modeling tool. Layering on widespread electrification could amplify these limitations, as well as introduce new aspects that models may not have been designed to accurately address. For example, the magnitude, shape, and flexibility of electrified loads are highly uncertain, especially in the end-use services for which electricity has historically not been a major source of energy supply (e.g., electric vehicle charging).[86]

In the present study, we attempt to address some uncertainties through sensitivity analyses addressing the assumptions with the largest impact on the evolution of the bulk power system, including load profile shapes, fuel prices, technology cost and performance, and system constraints. However, structural limitations in the ReEDS model—and in the overall approach used in the EFS analysis—prohibit more-detailed analysis.

This appendix highlights aspects of the scenario analysis and modeling for which higher-fidelity analysis would provide more conclusive findings. Beyond the caveats and limitations listed in this appendix, three documents—the companion EFS report that is focused on methods (Sun et al. 2020), the ReEDS documentation (Cohen et al. 2019), and the EFS demand-side adoption scenario analysis (Mai et al. 2018)—contain additional details and an explanation of assumptions and methods. For caveats and limitations that are specific to post-processing calculations related to our broader impacts analysis, see the discussion in Appendix C.

Load Profiles Under Increasing Electrification

The present study explores the impacts of electrification using established adoption scenarios for electric end-use technologies (Mai et al. 2018). This sequential scenario development process from the demand-side to the supply-side does not directly of fully capture the dynamic and simultaneous interactions between (1) electricity consumption (and adoption of electric technologies) and (2) the evolution of the bulk power system. For example, the adoption of electric technologies could be impacted by changes in electricity prices and/or rate structures, both of which depend on how the power system will evolve. Similarly, changes in electricity demand would impact electricity prices and opportunities for bulk power system expansion.

Also, this analysis assumes static end-use service demand requirements across all scenarios, but in reality, multiple external factors influence the amount of electricity demand associated with a given end-use service. For example, efficiency measures that tighten the building envelope could reduce the amount of energy and electricity required to maintain a comfortable air temperature, which would influence both summer and winter loads in certain regions under the electrification scenarios. In addition, the effects of climate change on ambient temperature could have pronounced impacts on space heating and cooling requirements. Though the ReEDS model can evaluate changes in ambient temperature on electricity demand and supply (Sullivan, Colman, and Kalendra 2015; Cohen et al. 2014), this capability was not employed for the present

[86] The magnitude, shape, and flexibility of other electrified end uses are similarly uncertain (e.g., space heating from cold-climate heat pumps, heat pump water heaters, industrial curing, etc.), but the uncertainty in vehicle charging is amplified by the large-magnitude of load growth associated with this end-use.

study because the method involves scaling of electricity demand that would be inconsistent with our exogenous electrification-dependent demand profiles.

Representation of Demand-Side Flexibility

There are several limitations associated with our representation of demand-side flexibility, which are detailed in Sun et al. (2020). In terms of scope limitations, ReEDS currently considers only a limited set of energy storage options, which does *not* include longer-duration storage options that could provide seasonal or multiday flexibility (Melaina et al. 2015). Such options would compete with or possibly degrade the value of flexible load. In addition, flexibility from sources that are not directly electric end-use technologies (e.g., thermal energy storage from buildings and industry; see Text Box 1) is not modeled, as this analysis focuses on the impacts of direct electrification. Moreover, costs associated with load shifting are not modeled, including enablement and management costs for the program provider (e.g., communication technology requirements), and comfort or inconvenience costs for consumers.[87] In practice, this means all demand-side flexibility is dispatched when it is available to the bulk power system operator, without full consideration of these other factors.

Finally, our representation of demand-side flexibility is limited in its treatment of losses (e.g., recovery energy), changes (e.g., lower electricity use due to AC postponement), and the full set of operational constraints associated with load shifting, due to the parameterized implementation that is required for the temporal resolution in ReEDS. In particular, assessing the feasibility of and challenges associated with operating a power system with high levels of flexibility (sourced from demand sectors and/or supply options) would require full chronological and hourly modeling. Planned work for the EFS includes performing more-detailed unit commitment and economic dispatch modeling to test the findings associated with system flexibility in the present study. This future modeling will be particularly valuable for high electrification scenarios in which storage and demand-side flexibility are relied on more heavily, as well as for scenarios with greater variability in electricity supply.

Representation of Natural Gas System

The representation of the natural gas system in the present analysis reflects a combination of results from the ReEDS and EnergyPATHWAYS models. The ReEDS power sector model does not directly represent the natural gas system, but instead relies on supply curves to reflect how the delivered natural gas prices to power generators interact with natural gas consumption in other sectors of the economy (see Sun et al. 2020 for details). In addition, the ReEDS model represents some of the challenges associated with bringing natural gas to pipeline-constrained regions through regional natural gas price multipliers, which are applied to these supply curves.

There are multiple limitations associated with applying ReEDS' indirect representation of the natural gas system to scenarios representing widespread electrification. First, the natural gas supply curves are derived from the U.S. Energy Information Administration's gas resource

[87] However, if the load flexibility is motivated through incentive programs, rate structures, or other mechanisms that are financially beneficial to the end user, at least some of these costs would be compensated. Nonetheless, we do not model all *system* costs related to demand-side flexibility (e.g., communications equipment and administrative costs). See Hledik et al. (2019) for a focused analysis on the potential costs and benefits of enhanced load flexibility.

and technology cases (EIA 2018a), which are typically designed to capture marginal changes to natural gas demand. Second, the regional natural gas price multipliers are based on approximations from historical experiences only. It is possible that neither of these assumptions would hold under scenarios representing widespread electrification, which could involve dramatically different levels of natural gas consumption, as well as a regional, temporal, and sectoral redistribution of natural gas consumption.

Despite these limitations in the ReEDS model, results from EnergyPATHWAYS allow us to estimate how changes in natural gas consumption—within and between sectors—could affect system-level expenditures. For example, one potential impact of electrification is that fixed costs for gas delivery infrastructure could be spread to a smaller number of consumers who remain reliant on gas, thereby driving up costs for these consumers. These potentially important impacts are estimated through the EnergyPATHWAYS representation of a depreciation of the existing rate base, which occurs over the financial lifetime of a natural gas pipeline. However, accurately evaluating these impacts would require consideration of local dynamics within a natural gas distribution system, and doing so would exceed the spatial resolution of models used here.

Finally, neither model explicitly represents fuel supply resources, infrastructure, and delivery mechanisms, so estimating how much natural gas infrastructure would be required under widespread electrification is difficult. For example, the potential redistribution of natural gas demand across sectors and regions under increasing electrification could require a corresponding change to long-distance natural gas pipelines and storage. On the end-use side, expanded adoption of technologies fueled by natural gas (e.g., natural gas vehicles and hybrid natural gas-electric space and water heaters) is not considered here, as the EFS scenario design focuses solely on direct end-use electric-only technologies.

Representation of Distribution-Level Impacts

Similar to the previous section, caveats around our analysis of the impacts of electrification on the electricity distribution system require consideration of both the ReEDS and EnergyPATHWAYS models. While the scope of the ReEDS model only includes the bulk power system, EnergyPATHWAYS estimates the amount of revenue a utility must collect through rates in each year to pay all costs associated with the distribution system. This "distribution revenue requirement" includes ongoing expenses and debt service on past investments, which are calculated in EnergyPATHWAYS using tariff numbers from NEMS, scaled with the simultaneous peak load on distribution feeders. Therefore, energy system-wide results in this analysis include an estimate of the costs associated with a potential electrification-driven increase in new distribution system equipment and costs. However, we do not include any evaluation of the potential for electricity retail rate evolution under widespread electrification, including the adoption of alternative rate structures and the incentives required to compensate users for providing demand-side flexibility.

This analysis includes only a narrow representation of DERs, which is limited to distributed photovoltaics (PV), based on results from the Distributed Generation (dGen) model.[88] In particular, we apply the levels of rooftop PV adoption—which vary with fuel price, technology cost, and system constraint scenario definitions—directly from Cole, Frazier et al. (2018). However, no modifications were made to uniquely represent electrification, so the DER adoption in this analysis does not reflect any impacts of electrification on the cost-effectiveness of DER technologies. For example, it is not well understood how changes in the magnitude and shape of electricity demand from electric technology adoption could impact the economics of rooftop solar systems, in terms of either geographic location or the size of the most cost-effective system. Additional research is also needed to explore (1) whether there are regions in which the coincidence of electric vehicle adoption and cost-competitive rooftop solar intersect and (2) what their impact on distribution systems might be. Similar interactions exist between the adoption of energy efficiency measures and electric technologies.

Finally, the impacts of electrification on electricity retail rates, rate structures, and utility business models are active research areas, and they would influence the cost-effectiveness of DER systems and electrification and could significantly impact bulk power systems.

Representation of Reliability-related Constraints

The ReEDS model is a long-term capacity expansion model that simulates the least-cost bulk electricity system in the contiguous United States. The optimization framework used in ReEDS includes constraints that represent multiple grid services that are designed to support reliable grid operations; however, the model does not reflect all aspects of reliability. Specifically, constraints are included in the model to ensure that seasonal planning reserve requirements and three operating reserve requirements (contingency, regulation, and flexibility) are met. For planning reserves, ReEDS endogenously estimates capacity credit for wind and solar technologies, which vary by region, technology, penetration level, and scenario. ReEDS also endogenously considers how the amount of regulation and flexibility operating reserves increases with greater wind and solar generation. The capacity credit and reserve requirement estimates are based on and benchmarked with previous studies (Cole et al. 2018; Frew et al. 2018; Cole and Vincent 2019; Reimers, Cole, and Frew 2019; Zhou, Cole, and Frew 2018; Cole et al. 2017; Sigrin et al. 2014). All (planning and operating) reserve requirements are specified separately for different regions. Specific details on the amount of reserves, technology eligibility, and methods to estimate capacity credit and operating reserve requirements are described in the ReEDS documentation (Cohen et al. 2019) and the EFS companion report (Sun et al. 2020).

Changes to the future electricity system, including from increasing electrification, demand-side flexibility, and renewable penetration, could introduce additional grid services or change the nature of planning and operating reserves; however, such changes are not considered in our modeling. A full reliability assessment would be needed to identify any potential needed changes and to understand how our results might be altered from such changes. As stated above, the model does not include all existing grid services used by utilities and restructured electricity

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[88] dGen models the adoption of distributed energy technologies from the present day to 2050 for the residential, commercial, and industrial sectors of the contiguous United States (Sigrin et al. 2016). The rooftop PV adoption estimates from dGen are applied as exogenous inputs to the ReEDS model.

markets today, such as primary frequency response, non-spin, or ‘down’ reserves (Denholm et al. 2019). Furthermore, the operating reserves modeled in ReEDS are based on simple approximations given ReEDS’ limited temporal resolution. As a result, while ReEDS approximates resource adequacy requirements (through its inclusion of planning reserves) and some other aspects of reliability (including through the inclusion of multiple operating reserves), it does not ensure that the electricity system from the scenarios meets all current or future reliability requirements. Additional planned analysis for the EFS includes the use of more-detailed production cost modeling to better estimate the amount of unserved load and unserved reserves for a subset of the scenarios presented in this report. Additional reliability-focused analysis, such as voltage and frequency stability analysis, would be needed for a more-complete assessment of the reliability of any of the scenarios presented in this report.

Appendix B. Scenario Inputs

This appendix details cost and performance assumptions that define the end-use technology advancement and supply-side assumptions for the demand-side and supply-side sensitivities explored in this analysis. All other system costs not mentioned here are taken from the 2018 ATB mid-case (NREL 2018).

End-Use Technology Advancement

The nature and magnitude of the assumed technology advancements vary considerably by technology (e.g., between buildings and transportation services and across various technology configurations such as plug-in hybrid and battery electric vehicles with a variety of ranges and applications). Figure B-1 graphically summarizes how the Moderate and Rapid end-use technology advancement levels compare with the Slow level ones. The figure is from a prior EFS report (Jadun et al. 2017), which provides additional details about the end-use electric technology advancement trajectories.

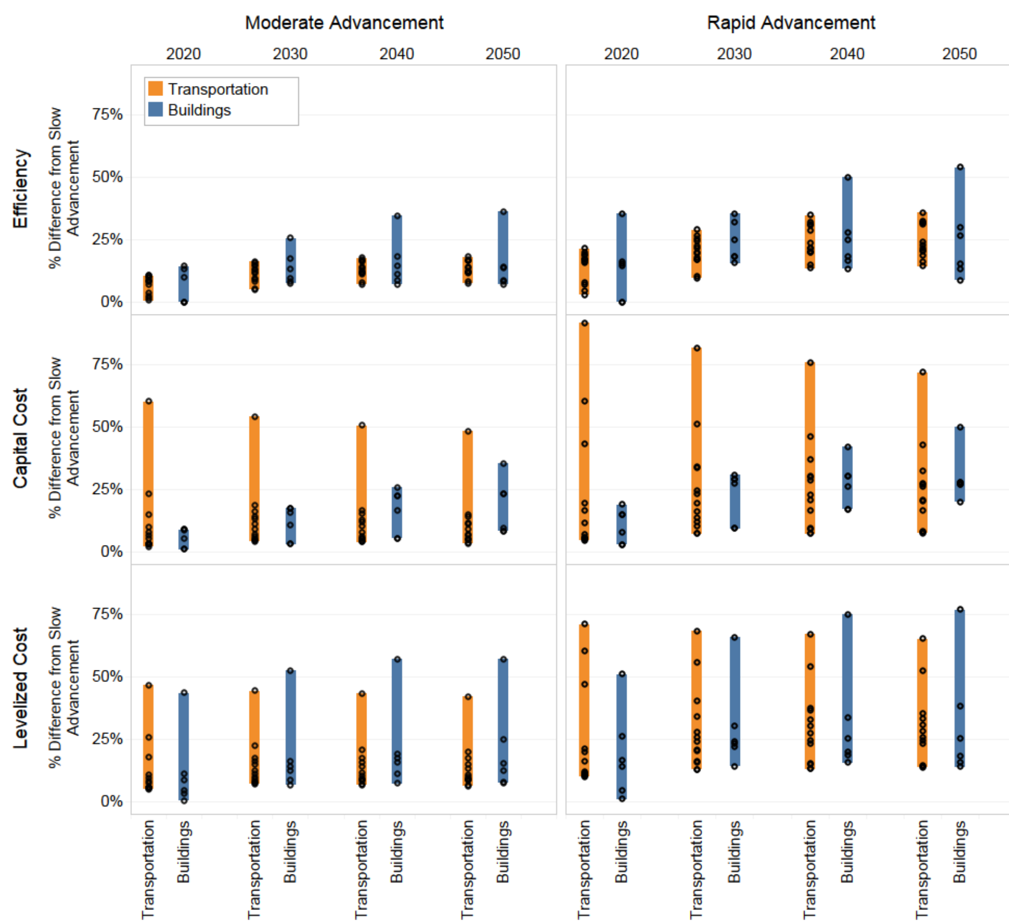


Figure B-1. Percentage difference for each technology from Slow Advancement estimates versus Moderate and Rapid Advancement estimates, by sector

The figure is from Jadun et al. (2017). Each colored bar represents the range of percentages by sector, and each black circle represents a specific technology.

Fuel Prices

The natural gas input price points are based on trajectories from the AEO2018 (EIA 2018a). The prices are shown in Figure B-2 and are from the AEO2018 Reference scenario, the Low Oil and Gas Resource and Technology scenario, and the High Oil and Gas Resource and Technology scenarios (EIA 2018a). Actual natural gas prices in ReEDS are based on the AEO scenarios, but they are not exactly the same; instead, they are price-responsive to natural gas demand in the ReEDS model. Each census region includes a natural gas supply curve that adjusts the natural gas input price based on both regional and national demand (Cole, Medlock, and Jani 2016), the net result of which is higher natural gas prices in the South Atlantic, New England, and Southwest regions, and lower natural gas prices in the West South Central, East North Central, and Middle Atlantic regions. Additional details about natural gas fuel price representation can be found in Sun et al. (2020). The reference coal and uranium price trajectories are from the AEO2018 Reference scenario and are shown in Figure B-2 as well. Both coal and uranium prices are assumed to be fully inelastic.

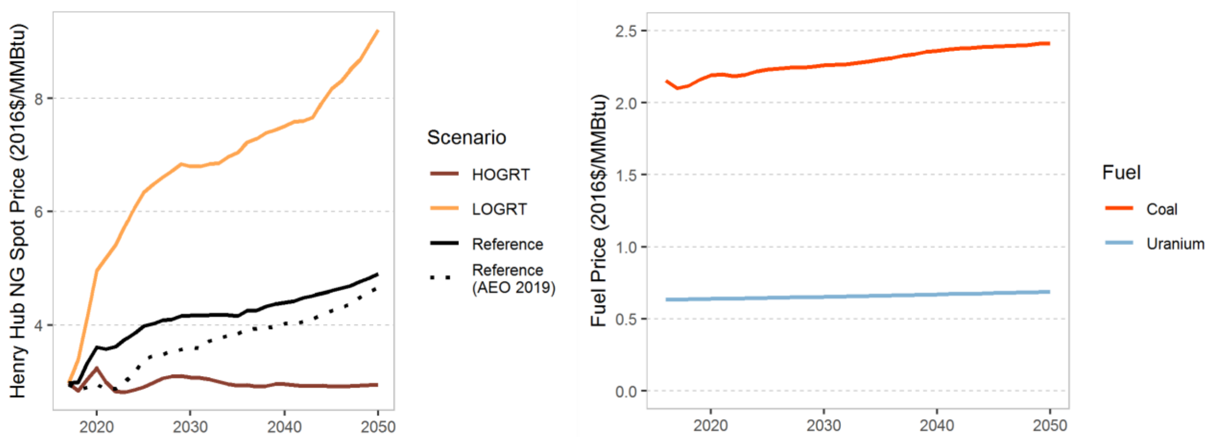
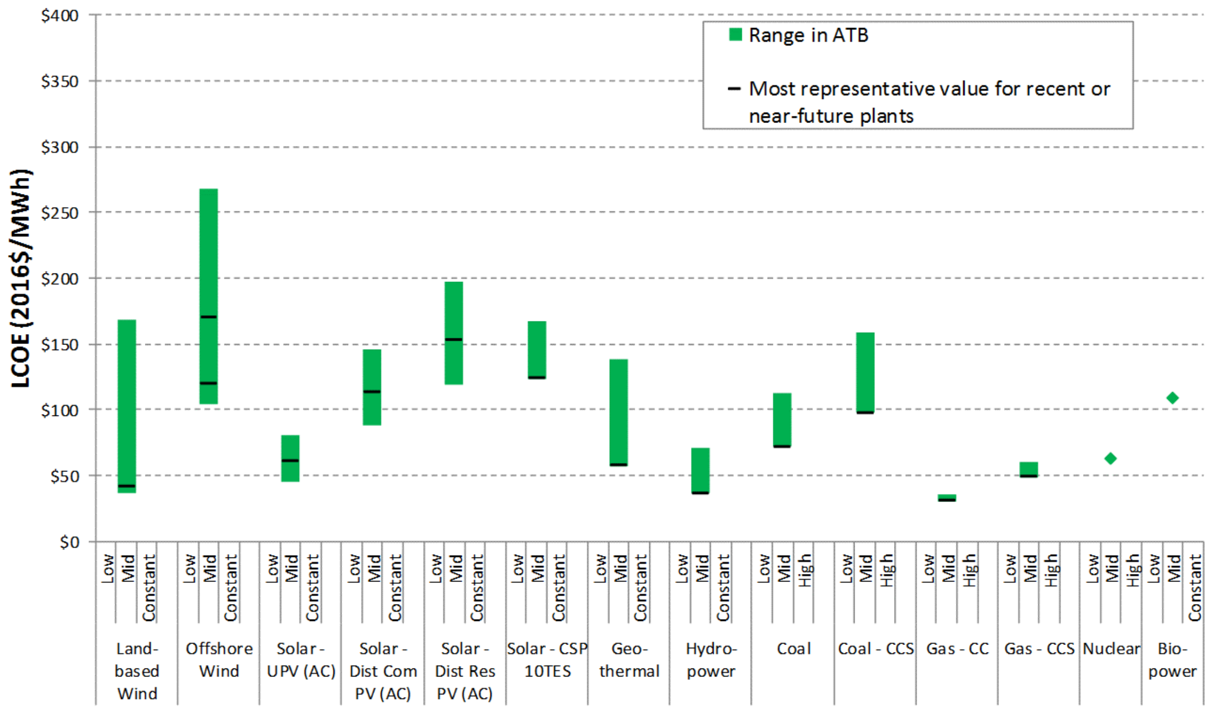


Figure B-2. Fuel price trajectories used in this analysis

ReEDS endogenously estimates natural gas prices using supply curves (Sun et al. 2020 describe the method employed), so prices in our scenarios differ from those shown in the figure. Furthermore, delivered prices (for all end uses including for power generation) differ from Henry Hub prices and can vary by region.

Technology Cost and Performance

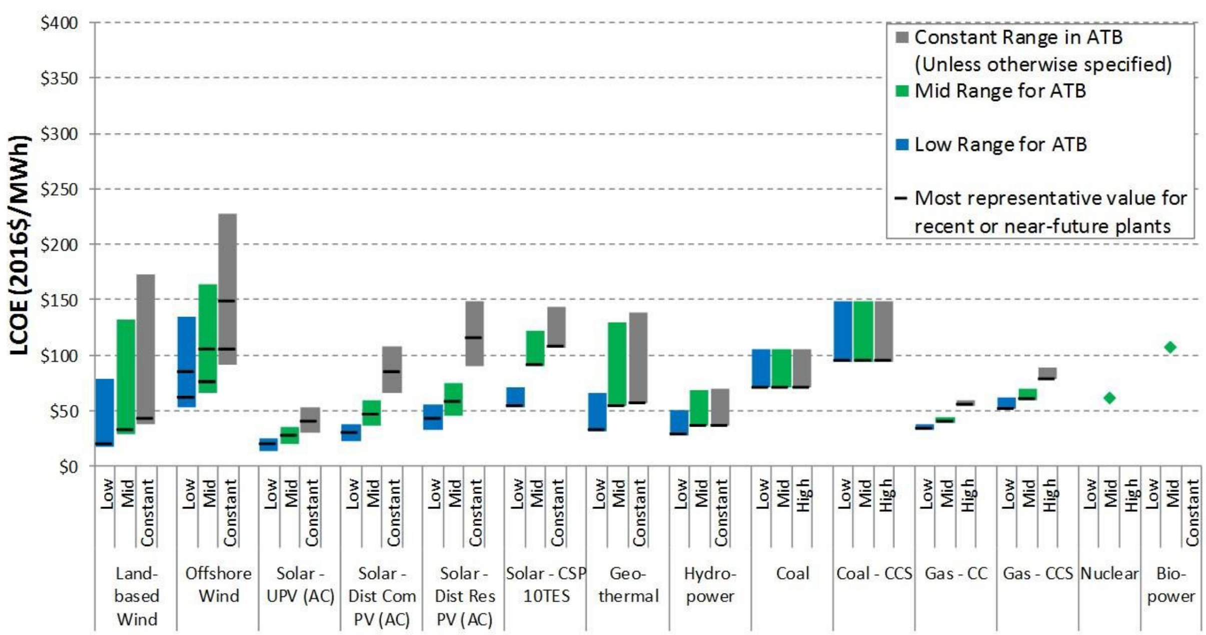
Cost and performance assumptions are taken from the 2018 ATB (NREL 2018), which includes Low, Mid, and Constant cost and performance trajectories through 2050 for the generating technologies used in the ReEDS model. Technology LCOE ranges from the 2018 ATB are shown in Figures B-3 through B-5 for 2016, 2030, and 2050 respectively. The mid-case LCOE trajectories from the ATB were used for all scenarios in this work except that the Lower RE Costs and Combined scenarios used the ATB low trajectory, and the Constant RE Costs scenario used the ATB constant trajectory.



2018 ATB LCOE range by technology for 2016 based on R&D financial assumptions

Source: National Renewable Energy Laboratory Annual Technology Baseline (2018), http://atb.nrel.gov

Figure B-3. LCOE ranges from the 2018 ATB for 2016



2018 ATB LCOE range by technology for 2030 based on R&D financial assumptions

Source: National Renewable Energy Laboratory Annual Technology Baseline (2018), http://atb.nrel.gov

Figure B-4. LCOE ranges from the 2018 ATB for 2030

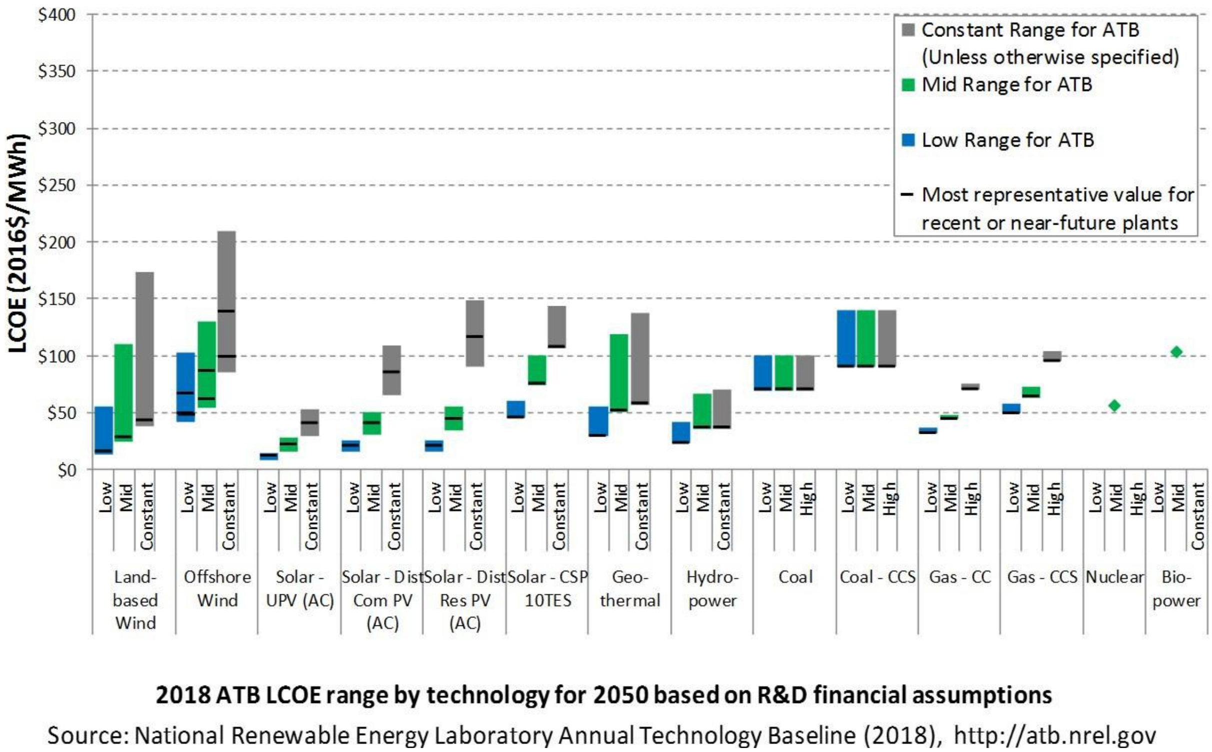


Figure B-5. LCOE ranges from the 2018 ATB for 2050

UPV = utility-scale PV, Dist Com PV = distributed commercial PV, Dist Res PV = distributed commercial PV, and 10TES = XYZ

Finally, Table B-1 includes select assumed capital costs, fixed operations and maintenance (O&M), and variable O&M costs for generating technologies used in this analysis. Values are given in 2017$ for plants that come online in 2020, 2030, and 2050.

Table B-1. Capital and Fixed and Variable O&M Costs for Generating Technologies Used in this Analysis[a]

2017$	Capital Cost ($/kW)			Fixed O&M ($/MW-yr)			Variable O&M ($/MWh)		
Technology	2020	2030	2050	2020	2030	2050	2020	2030	2050
Biopower	3,873	3,656	3,339	112,150	112,150	112,150	5.58	5.58	5.58
Coal-CCS[b]	5,677	5,370	4,833	82,100	82,100	82,100	9.70	9.70	9.70
Coal[c]	3,699	3,570	3,359	33,289	33,289	33,289	1.76	1.76	1.76
Gas-CC	1,047	1,000	926	10,605	10,605	10,605	2.78	2.78	2.78
Gas-CC-CCS	2,165	1,988	1,695	33,750	33,750	33,750	7.20	7.20	7.20
Gas-CT	895	851	785	12,270	12,270	12,270	7.18	7.18	7.18
Geothermal	2,766	2,216	2,799	119,870	119,870	119,870	0.00	0.00	0.00
Hydro	2,504	2,826	2,659	40,050	40,050	40,050	1.33	1.33	1.33
Landfill Gas	8,765	8,542	8,039	417,020	417,020	417,020	9.29	9.29	9.29
Nuclear	5,721	5,527	4,892	101,280	101,280	101,280	2.32	2.32	2.32
Ocean	3,005	3,005	3,005	147,113	147,113	147,113	0.00	0.00	0.00
Oil, Gas, and Steam	1,110	1,081	1,018	28,866	28,866	28,866	5.37	6.55	9.73
Onshore Wind[d]	1,563	1,495	1,483	50,901	47,130	39,589	0.00	0.00	0.00
Offshore Wind[d]	5,107	3,699	3,007	136,733	133,772	127,848	0.00	0.00	0.00
Utility PV	1,107	827	674	8,259	6,943	5,718	0.00	0.00	0.00
CSP-TES[e]	7,284	6,472	5,611	65,418	51,197	51,197	3.62	3.62	3.62

[a] Wind and solar cost assumptions come from the 2018 ATB; other technology costs are based on AEO2018 (EIA 2018a) costs with adjusted O&M for existing coal plants based on plant specific data.

[b] CCS = carbon capture and storage.

[c] ReEDS has multiple types of coal technologies. The results presented here show the cost assumption for pulverized coal with scrubbers (post-1995).

[d] The results shown here represent the median capital cost for different wind resource classes. However, wind technology improvements are largely in capacity factor improvements: from 2018 to 2050, onshore wind technology capacity factors increase by 13%–61%, and offshore wind technology capacity factors increase by 6%–9% (where the range represents different resource classes).

[e] TES = thermal energy storage.

Storage Costs

The default, low-cost, and high-cost trajectories for energy storage technologies are taken as the mid-case, low-case, and high-case storage costs for battery storage in Cole, Marcy et al. (2016). The utility-scale cost trajectories are shown in Figure B-6 for a four-hour duration battery storage system. The battery systems are generic battery storage systems, but the costs in Cole, Marcy, et al. (2016) were generally based on lithium-ion systems. The systems are assumed to have a round-trip efficiency of 85% and a 15-year lifetime, with ~1 cycle per day. Additional cost details, such as O&M cost trajectories, are in Cole, Marcy, et al. (2016).

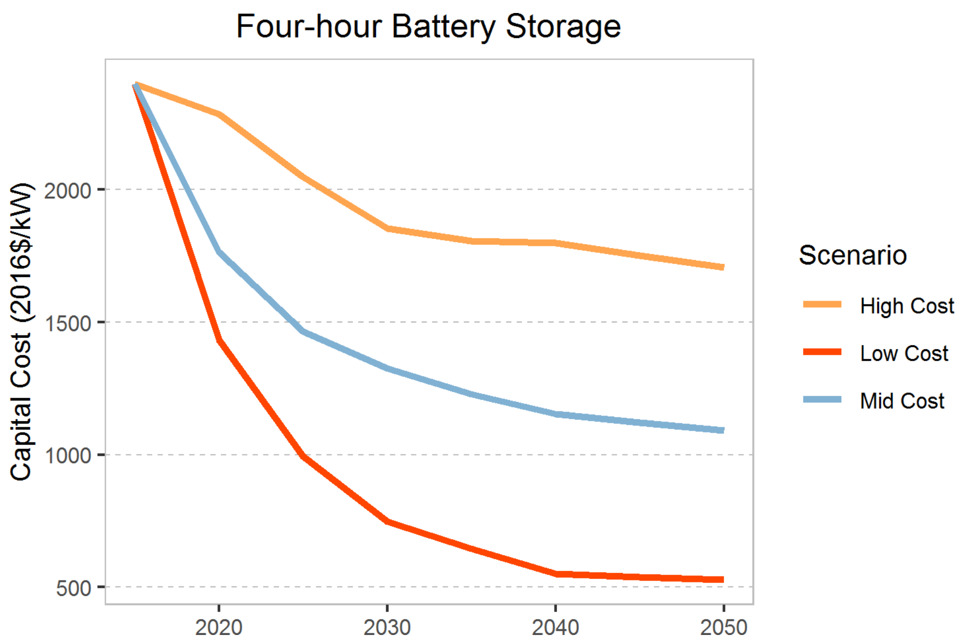


Figure B-6. Battery storage cost trajectories used in this analysis

Appendix C. Supporting Analysis of Broader Impacts

This appendix describes the methodologies used to calculate a variety of broader impacts of electrification, which are detailed and presented for the Base Case scenarios in Section 2. Related results are also presented for demand-side flexibility variations in Section 3.3, and for the supply-side sensitivity scenarios in Sections 4.2 through 4.4.

C.1 System Costs Calculation

Here we document the assumptions and method for energy system cost calculation, along with guidance for interpreting the results. First, we introduce the scope and cost categories in the energy system cost calculation, and we explain any data preprocessing where applicable. Next, we document the present value calculation method and assumptions used to generate the results presented in this report.

Cost Categories and Data Source

Energy system costs presented in this report include both electric system costs and demand-side system costs associated with building and operating the U.S. energy system. Electric system costs are mainly derived from ReEDS model results, whereas electricity distribution and demand-sector system costs are from the EnergyPATHWAYS model. Cost categories and corresponding data sources are listed in Table C-1, and key assumptions for each cost category are discussed below.

Table C-1. Cost Categories in Energy System Cost Calculation and the Associated Data Source

Cost Category	Data Source(s)
Electric Sector: Generation and Storage Capital	ReEDS, dGen
Electric Sector: Transmission and Distribution	ReEDS, EnergyPATHWAYS
Electric Sector: Fuel Consumption and O&M	ReEDS, dGen
Demand Sectors: Fuel Infrastructure	EnergyPATHWAYS
Demand Sectors: Fuel Consumption and O&M	EnergyPATHWAYS, ReEDS
Demand Sectors: Equipment Capital	EnergyPATHWAYS

Electric Sector: Generation and Storage Capital

This category includes all the capital investment costs for generation and storage technologies in the electric sector, including grid connection costs, water access purchases, and other capital financing costs. Most of the data are from ReEDS, which (1) considers regional variations that reflect costs differences in supply chain, labor, and permitting costs, and (2) captures costs associated with the electric portion of utility-scale combined heat and power plants.[89] However, capital costs for distributed PV are calculated based on the deployment of distributed photovoltaics (PV) from the dGen model. Unique data are available for all 29 scenarios.

[89] Note that this restricted scope could lead to a potential underestimate of the total energy-system costs, but this effect is expected to be minor compared to all other system cost categories.

Electric Sector: Transmission and Distribution

This category includes inter-regional transmission investment costs from ReEDS and annual revenue requirements for distribution utilities from EnergyPATHWAYS. It does not consider revenue requirements for transmission utilities. Distribution revenue requirement costs are calculated using tariff numbers from NEMS and are scaled with the simultaneous peak load on distribution feeders.

The transmission data are unique for all 29 ReEDS scenarios, but the distribution revenue requirement data only vary across the nine Base Case scenarios (i.e., combinations of Reference, Medium, and High electrification with Rapid, Moderate, and Slow end-use technology advancement). In other words, the distribution revenue requirement data from the Base Case scenarios with Reference and High electrification are applied to all demand-side flexibility and supply-side sensitivity scenarios (with the corresponding electrification levels).

Electric Sector: Fuel Consumption and O&M

This category includes all fuel costs and all fixed and variable O&M costs in the electric sector. Most of the costs are from ReEDS, with the exception of distributed PV O&M costs, which are calculated from the distributed PV generation in dGen model. The data are available for all 29 scenarios.

Any upstream fuel delivery costs related to power generation are assumed to be included in the delivered fuel prices used in ReEDS. This includes delivery costs and infrastructure costs for the electric sector. For instance, the portion of gas transmission pipelines that supply power plants are in this category. Fuel infrastructure and delivery costs for other demand sectors are considered in the Demand Sectors: Fuel Infrastructure category.

Demand Sectors: Equipment Capital

This category considers the incremental demand-side equipment capital costs of Medium and High electrification, relative to the Reference electrification level. The different convention used in this category reflects that *total* demand capital costs would represent the sum of all business and consumer purchases of equipment that use energy, which are not conventionally thought of as energy system costs. Therefore, we show demand-sector equipment capital costs in incremental terms (i.e., compared to another electrification scenario), to demonstrate electrification-induced equipment capital cost changes. For instance, the incremental cost of a heat-pump hot water heater over a gas water heater represents the portion of the demand-side capital cost that resulted from electrification, and it can be compared with the resulting changes in other system costs.

The data are available for all nine end-use technology advancement scenarios from EnergyPATHWAYS model. Incremental equipment capital costs relative to Reference electrification level with Base Case assumptions are used for other demand-side flexibility and electric sector variation scenarios under corresponding electrification levels.

Demand Sectors: Fuel Infrastructure

This category includes fuel infrastructure costs that are unrelated to the electric sector. The data are available for the Reference, Medium, and High electrification levels (all with Moderate end-use technology advancement), which are applied to all other scenarios with the corresponding electrification levels.

The annual revenue requirement associated with natural gas transmission and distribution pipelines shows the largest difference between scenarios. These cost estimates are based on historical revenue requirements pegged to total gas throughput on each part of the system. Pipelines are depreciated over their assumed physical lifetime and are paid for even if utilization drops. The portion of gas transmission pipelines allocated to electricity generation is subtracted from the overall calculation because these costs are assumed to be embedded in the delivered fuel prices for electricity generation in ReEDS, which are captured under the Electric Sector: Fuel Consumption and O&M category.

Demand Sectors: Fuel Consumption and O&M

This category represents fuel costs for all non-electric final energy demand in demand sectors, where the largest components are petroleum products and natural gas. In addition, it includes fuel fixed and variable O&M costs for end-use equipment. Natural gas fuel costs are scaled based on the delivered natural gas price to the electric sector (modeled in ReEDS), to reflect price elasticity. In particular, the scaled EnergyPATHWAYS fuel costs are calculated as:

$$\text{EP scaled cost} = \text{EP original cost}_{yyyyyyyy,yyeeyyee\ eeyyllyyee} \times \frac{RRRRRRRRRR\ ddRRddddddRRddRRdd\ ppddddppRR\ tttt\ RRddRRppttddddpp\ ssRRppttttdd^{nnyynnnnnnnnyyee}_{yyyyyyyy,yyeeyyee\ eeyyllyyee}}{AARRAA\ ddRRddddddRRddRRdd\ ppddddppRR\ tttt\ RRddRRppttddddpp\ ssRRppttttdd^{nnyynnnnnnnnyyee}_{yyyyyyy}}$$

where the denominator is the national delivered natural gas price to the electric sector from the AEO2018 Reference case (EIA 2018a).

Demand-side O&M costs and non-natural gas fuel consumption costs data are available for nine end-use technology advancement scenarios directly from EnergyPATHWAYS. Base Case data are used for other demand-side flexibility and electric sector variation scenarios under corresponding electrification levels. Because demand-side natural gas fuel costs are scaled using scenario-specific delivered natural gas price from ReEDS, these data are available for all 29 scenarios.

Present Value Calculation Method

The present value calculation for total energy system costs follows the electric system cost calculation method used in ReEDS (Cohen et al. 2019, 15), and it demonstrates a detailed present value calculation method for some defined economic analysis period.

To calculate the net present value of total energy system costs, the cost in each future year (t) is discounted to the initial year of the economic analysis period (t_0) by a social discount rate (d_{social}). It is important to note that the real social discount rate used here for the present value calculation is different from the investment discount rate assumptions, or weighted-average cost of capital (WACC) assumptions, which ReEDS and EnergyPATHWAYS use for investment decisions.

The present value (represented as PV in the equation), consists of three cost components. The first component is the present value of all operational costs in the energy sector for the analysis period ($PV_{operational}$), which includes fixed and variable O&M costs for all sectors, as well as fuel costs. The second component is the present value of all new capital investments ($PV_{capital1}$) that can be fully utilized before the end of the analysis period (i.e., the investment year plus the economic lifetime does not exceed the final year of economic analysis, t_f). The third component is the present value of all investments that cannot be fully utilized before the end of the analysis period ($PV_{capital2}$); in other words, the investment year plus the economic lifetime exceeds the final year of economic analysis.[90] The present value of energy system costs is then calculated as:

$$PPPP = PPPP_{nnooyyyyyynnnnnnnyyee} + PPPP_{eeyyyoommnyyee1} + PPPP_{eeyyyoommnyyee2}$$

For $PPPP_{eeyyyoommnyyee2}$, the present value is scaled to account for only the years that the investment is utilized. The scaling factor is defined as the ratio of (1) the capital recovery factor ($CCRRCC$) for the full economic lifetime to (2) the capital recovery factor for the number of years that the investment is used (i.e., $tt_{ff} + 1 - tt$). In particular,

$$PPPP_{eeyyyoommnyyee2} = \underset{mm=mm_0}{\overset{nn_{ff}}{\text{?}}} CC_{eeyyyoo,mm} \times ssppssdddssss\ ffssppttttdd \times \frac{1}{(1 + dd_{ssnneennyyee})^{mm-mm_0}}$$

$$ssppssdddssss\ ffssppttttdd = \frac{CCRRCC(dd_{mmnnllyyssnn}, ddtt)}{CCRRCC(dd_{mmnnllyyssnn}, tt_{ff} + 1 - tt)},\ CCRRCC = \frac{dd_{mmnnllyyssnn}}{1 - \frac{1}{(1 + dd_{mmnnllyyssnn})^{eenn}}}$$

where $dd_{mmnnllyyssnn}$ is the investment discount rate, and $ddtt$ is the economic lifetime of the investment.

While EnergyPATHWAYS has annual cost data, ReEDS only models even years from 2010 to 2050. Thus, for all ReEDS cost results, we compute the operational costs for non-modeled year tt as the average of model years $tt - 1$ and $tt + 1$, and we divide the capital cost evenly between non-modeled year tt and modeled year $tt + 1$. In this present value calculation, the economic analysis period is 2019–2050, and a social discount rate $dd_{ssnneennyyee}$ (3% in real terms) is used.

It is important to note that $dd_{ssnneennyyee}$ differs from the WACC assumption for investment decisions ($dd_{mmnnllyyssnn}$), the latter of which is only used as a scaling factor in this calculation. In particular, $dd_{mmnnllyyssnn}$ is assumed to be 5.4% (in real terms) for all capital investments costs from both ReEDS and EnergyPATHWAYS in the present value calculation. This 5.4% WACC assumption is the same as what is used in ReEDS optimization for investment decisions. However, EnergyPATHWAYS assumes different WACC values for different demand-side technologies, based on time-value of money assumptions by sector. To check the impacts of different WACC assumptions, we calculate the present value of energy system costs using technology-specific WACC assumptions from EnergyPATHWAYS. Results are only 1% lower than those that arise when assuming a constant $dd_{mmnnllyyssnn}$ of 5.4% in the final calculation.

[90] For investments that will last beyond the end of the analysis period, the cost is reduced by a weighting factor.

The economic lifetime ($ddtt$) is assumed to be 20 years for all electric sector investments in ReEDS. EnergyPATHWAYS has technology-specific lifetime assumptions for demand technologies that range from less than one year (Lamp: 100 Equivalent A19 Halogen) to 25 years (natural gas boiler).

Caveats and Limitations

The system cost measures quantified in our analysis are based on direct accounting of capital and operating expenditures only; they do not account for potentially farther-reaching economic impacts to different stakeholders. For example, the system cost estimations exclude potential monetary impacts associated with energy security, environmental damages, health impacts, and other externalities. The models used for the EFS are not designed to estimate macroeconomic impacts to the U.S. and global economies, which can be affected by the energy transformation in the modeled scenarios and which can affect the feasibility of such transformations. In addition, the cost metrics used do not reveal distributional impacts. Further analysis is needed to assess the economic impacts by region, demography, and the wide range of stakeholders who would be affected by electrification.

C.2 Primary Energy Calculation

Primary energy estimation methods for renewable energy technologies are complex, and a consensus method is lacking. Some leading energy research organizations assume 100% efficiency whereas others assume a lower value (Newell, Iler, and Raimi 2018). In the present study, we apply the U.S. EIA's "thermal-equivalent" method, wherein the conversion rate is based on the annual national average efficiency of the remaining non-renewable generation mix (EIA 2012, 2018c). Such a method results in annual- and scenario-dependent primary energy conversion factors for renewable energy, with typical values ranging from about 6,700 to about 9,900 Btu/kWh in our scenarios.

We calculate final and primary energy using outputs from both the EnergyPATHWAYS and ReEDS models. For the electric sector, final electricity consumption is based on the electricity demand profiles from Mai et al. (2018) and adjusted based on the methodology described by Sun et al. (2020).[91] Electric sector primary energy is calculated as described above using ReEDS generation mixes.

Non-electric final and primary energy are estimated from EnergyPATHWAYS, based on the scenarios presented by Mai et al. (2018). In addition, final and primary energy values in the present study incorporate an additional ~10 quads of energy consumption—associated with refining; oil, coal, and natural gas extraction; and combined heat and power—from the EnergyPATHWAYS supply model. As a result, the final and primary energy estimates presented in this study are similar in scope to those in the AEO2019 (EIA 2019a), but they differ slightly from those presented by Mai et al. (2018), which was restricted to only demand sectors.

The fossil fuel and energy consumption estimates presented here provide indicators of how electrification might impact overall energy use and the shifts in energy use across sectors and

[91] These numerical values differ slightly from those reported in Mai et al. (2018) due to minor adjustments applied for the power sector modeling presented in the current report and Sun et al. (2020).

fuels. Although the qualitative trends are likely robust, several limitations in our modeling could affect the quantitative values presented. First, this analysis uses a single method (the thermal-equivalent method) to calculate primary energy consumption, whereas other approaches might yield a different conclusion about the total primary energy impacts of the different levels of electrification.

Second, this analysis does not capture any dynamics about how oil markets and U.S. consumers might respond to electrification-driven reductions in demand for petroleum-based fuels. On the one hand, vehicle electrification could lead to a reduction in oil production, which could drive a corresponding increase in the cost of producing natural gas, because the opportunity for producing associated gas would be reduced. On the other hand, reduced end-use demand for natural gas could drive natural gas producers to increasingly export their product in the form of liquefied natural gas, which would counteract the more domestic-focused price elasticity that is represented here. Finally, this analysis reflects exogenous assumptions about consumer adoption of electric technologies, which could be disincentivized as increasing electrification puts downward pressure on demand and prices for oil and natural gas. To mitigate some of the uncertainties about natural gas resources and our modeling, we include several gas resource sensitivities, and we present the resulting range of primary energy estimates in Section 4.

C.3 Air Emissions Calculations

Similar to the previous subsection, we calculate air emissions from both the ReEDS model and the EnergyPATHWAYS model. In particular, air emissions (CO_2, SO_2, and NOx) from the power sector are computed endogenously in ReEDS, and CO_2 emissions from the demand sectors are computed endogenously in EnergyPATHWAYS (by region, year, vintage, technology, and fuel type). Demand sector SO_2 and NOx emissions are computed by multiplying final energy use (from EnergyPATHWAYS) by emission factors—which reflect the amount of emissions generated per unit of energy consumed—on a regional, annual, technology-specific, and fuel-specific basis. Emission factors for direct energy use in demand sectors are taken from the GCAM (Shi et al. 2017). By design, these emissions factors are intended to be consistent with both (1) the stock of end-use technologies available in the market today and (2) the expected future performance of similar technologies based on current emissions regulations across multiple sectors. Select sources for future emissions factors include the U.S. Environmental Protection Agency's EPAUS9r2014 MARKAL energy modeling framework (Shi et al. 2017), MOVES 2014 (Shi et al. 2017),[92] and Shi et al (2017).[93]

Electric Sector Emissions

Electric sector CO_2 emissions are produced at fossil fuel-fired power plants, and absolute emissions depend on heat rates (which do not change significantly over time), fossil fuel consumption (which is a function of electricity demand and utilization rates), and the presence (or absence) of carbon capture technologies. The generation mix also affects electric sector SO_2 and NOx emissions—which are produced at a higher rate from coal-fired power plants than they are from NG-CC plants—but the amount of these emissions also depends on assumptions about

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[92] MOVES (MOtor Vehicle Emission Simulator) is the EPA regulatory model for on-road transportation.
[93] Shi et al. (2017) compared GCAM air pollutant emissions to U.S. Environmental Protection Agency inventories and harmonized assumptions used to derive these emissions factors with EPA assumptions.

emission control technologies that could be adopted as a result of relevant regulations. This analysis relies on default emission rates and regulations in ReEDS, which generally assumes both improvements to technology-specific emission controls over time and regional caps on SO_2 and NOx (Cohen et al. 2019), based on current laws and regulations.

Transportation Emission Factors

This analysis is limited to emissions from on-road transportation systems (light-duty vehicles, buses, and medium- and heavy-heavy duty trucks), which were responsible for over one-third of total energy-sector NOx emissions in 2014.[94] Emission factors for these technologies are taken from GCAM (which derived them from EPA MOVES); they vary by census region, vehicle type, year, fuel type, and vintage. In particular, transportation emissions factors are assumed to decline for future vehicle vintages, as pollution control and efficiency progress. However, emission factors increase over the lifetime of a vehicle as both pollution control equipment and engine performance degrade.

To demonstrate this, Table C-2 presents example transportation NOx emission factors for gasoline-powered vehicles in different classes (compact car and pickup truck), vintages (2015 and 2020), and years (which reflect the first 15 years of operation). A comparison across vehicle classes reveals that a compact car has a lower initial emission factor, and a slower increase in its emission factor (as the vehicle ages), than a pickup truck of the same vintage. In addition, comparison across vintages reveals that a new compact car in 2020 has a lower initial emission rate than a new car in 2015, due to technology progress and more-stringent regulations over time (based on existing rules and laws). In addition, the 2020 car's emission factor increases more slowly over time.

Table C-2. Examples of NOx Emission Factors Over Time for Gasoline-Powered Vehicles[a]

Vehicle Class	Vehicle Vintage	Year	Emission Rate (Tg/EJ)
Compact car	2015	2015	0.019
		2020	0.030
		2025	0.055
		2030	0.079
Pickup truck	2015	2015	0.022
		2020	0.031
		2025	0.055
		2030	0.104
Compact car	2020	2020	0.0164
		2025	0.031
		2030	0.042
		2035	0.056

[a] Data are derived from Shi et al. (2017).

[94] The transportation sector's contribution to energy sector SO_2 emissions is negligible.

Industrial Emission Factors

Emission factors for direct energy use in industry are taken from the GCAM (Shi et al. 2017). The industrial emission factors vary by pollutant type, year, and fuel type (Figure C-1), and in the case of refineries, emission factors are also assumed to vary widely by state.

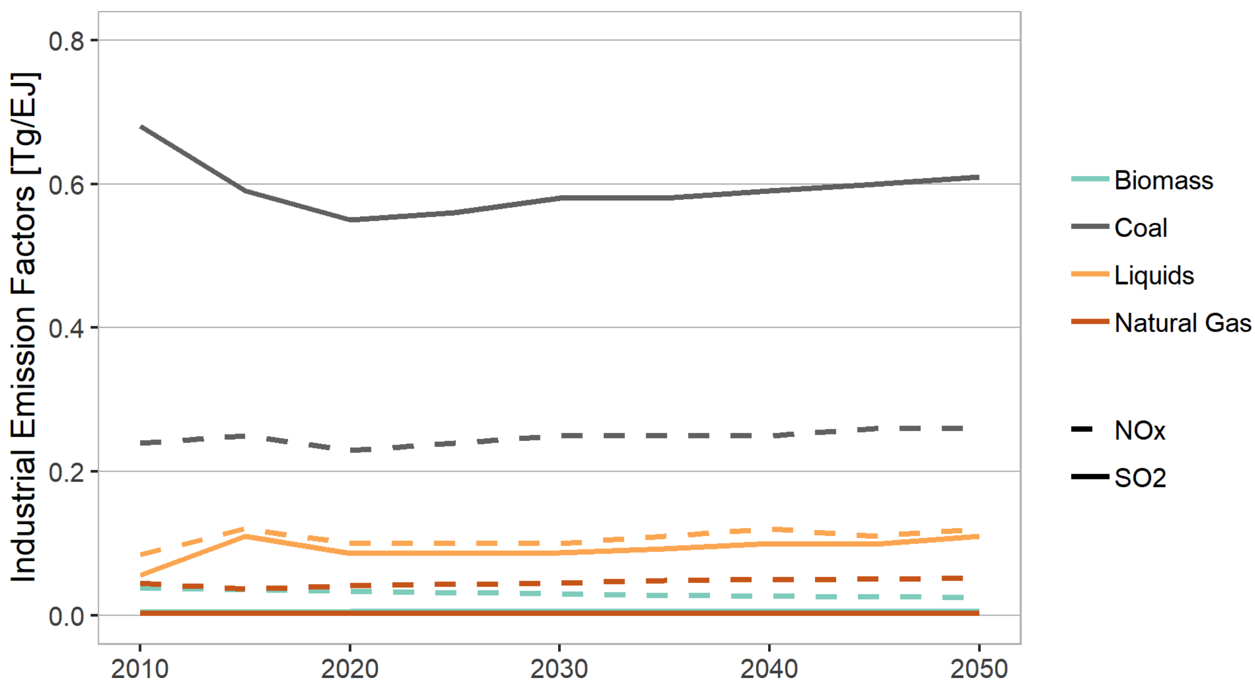

Figure C-1. Industrial emission factors by year and fuel type

Solid and dashed lines represent SO2 and NOx emission factors respectively.

Building Emissions Factors

For residential and commercial buildings, current emission factors are estimated by dividing NOx and SO_2 emissions from EPA inventories (by region, end-use, year, and fuel type) by the corresponding final energy use as estimated by Mai et al. (2018). These emission factors are held constant over time, because end-use equipment in buildings is not currently subject to emissions regulations.

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