

focused on supporting investment in needed and beneficial transmission infrastructure – investments that Congress and the Commission have recognized are critical to establish a resilient, reliable, cost-effective, and modern, and clean bulk power system.

On March 2, 2021, the Commission issued a Notice of Technical Conference announcing that the Commission will convene a technical conference to discuss electrification – the shift from non-electric to electric sources of energy at the point of final consumption (e.g., to fuel vehicles, heat and cool homes and businesses, and to provide process heat at industrial facilities). Subsequently, the Commission issued a Supplemental Notice of Technical Conference on April 14, 2021 announcing an agenda and speakers for the technical conference, which includes Larry Gasteiger, Executive Director of WIRES as a panelist for session 2 entitled “Infrastructure Requirements of Electrification.” Panel 2 will focus, among other things, on how transmission owners and system operators in both regional transmission organization (RTO) and independent system operator (ISO) regions and non-RTO/ISO regions are planning to cost-effectively and reliably integrate changes in electricity demand due to electrification and whether there are any existing challenges in transmission, interconnection, and resource adequacy planning processes that need to be addressed. WIRES submits the following pre-conference remarks and materials in response to the Supplemental Notice.

In 2019, WIRES released a report prepared by the Brattle Group that found that the drive towards electrification of transportation and heating in the U.S. will require major new electric transmission infrastructure. The report, titled *The Coming Electrification of*

the North American Economy: Why We Need A Robust Transmission Grid, projected that investments totaling \$30 to \$90 billion will be needed by 2030, and significantly more than that by 2050.²

According to the report, the number of electric vehicles on the road and other electricity used are slated to increase significantly, placing stress on the existing grid. The Brattle Group projected that electric vehicles (EVs) will jump from one million in 2019 to seven million in by 2025 and increase exponentially thereafter. The study found that electrification of the transportation, heating, and data application sectors could significantly increase electricity demand and the need for low-carbon and renewable electric generation resources. A more robust infrastructure would therefore be necessary to support this fundamentally different energy economy.

A similar trend is occurring in the space heating sector. Electric heat pumps, which already are common in regions of the U.S. with moderate climates, are becoming less expensive and more efficient in colder climates. Advances in technology could even make it increasingly possible to electrify many industrial processes.

The WIRES report examined transmission investment based on two scenarios:

- A “base case,” where the current momentum towards EVs continues to accelerate, and heat pumps become competitive space heating technology in some parts of the U.S.; and

² The Brattle Group, *The Coming Electrification of the North American Economy*, (March 2019) <https://wiresgroup.com/wp-content/uploads/2020/05/2019-03-06-Brattle-Group-The-Coming-Electrification-of-the-NA-Economy.pdf>

- A “high case,” where electrification powers all transportation, as well as space and water heating by 2050.

Examining these two scenarios, and depending on the pace of adoption of electrification, the study forecasts the need for \$30 to \$90 billion in incremental investment in new transmission infrastructure by 2030 to connect all of the new generation resources and to maintain reliability. When the forecast projects to 2050, the required transmission investment increases to an additional \$200 to \$600 billion.

The report identifies a number of critical takeaways for policymakers to consider:

- Policymakers setting clean energy goals must take into account the transmission investments that will be needed to cost-effectively achieve these goals.
- Transmission planners should take the following steps:
 - Start anticipating the impact of electrification and integrate it into planning processes now;
 - Adopt a “no regrets” planning approach to account for uncertainties in the timing, location, and scale of electrified loads and renewable resources in order to avoid being unprepared for rising demand and higher-cost solutions; and
 - Continue to expand consideration of larger scale interregional projects that will increase capacity across regions, thereby accommodating regional variations in peak loads, generation patterns, and the diversification of load served by renewable resources.

A copy of the report is attached for the Commission’s consideration.

Respectfully submitted,

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April 21, 2021

ATTACHMENT

The Coming Electrification of the North American Economy

Why We Need a Robust Transmission Grid



WIRES

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March 2019



WIRES Preface

WIRES¹ offers this important study by The Brattle Group to demonstrate the importance of proactive infrastructure planning in anticipation of the electrification of major sectors of the U.S. economy. This groundbreaking report finds that electrification will drive the need for significant investment in the electric transmission grid to cost effectively support new demand for electricity. At the same time, the economics of natural gas and renewable generation resources will continue to drive changes to the mix of fuels on the grid. Meanwhile, public policies surrounding clean energy and climate concerns are already changing the face of corporate strategies and utility operations, which are increasingly regional, inter-regional, and even national in scope. Regional grid planners and managers are struggling to stay ahead of these changes. These factors, combined with the coming sea change in electric usage, indicate there is an urgent need for more effective longer-term planning to support an electrified economy and the new fuel mix. This is the latest in a series of WIRES studies for policy makers interested in the evolving high voltage electric grid.

Above all, this new study makes a clear case for accelerating development and integration of the interstate grid. It highlights how the North American economies will become more electrically driven and contemplates new demands on an aging transmission network that has been planned based on historical assumptions and traditional usage patterns. Looking 10 and 30 years into the future, this analysis estimates that electrification of the transportation sector (i.e., electric vehicles), deployment of electric heat pumps, and other technologies will increase electricity demand overall and therefore magnify the need for investment in transmission. As soon

¹ WIRES is an international non-profit trade association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. WIRES members include integrated utilities, regional transmission organizations, renewable energy developers, and engineering, environmental, and economic policy consulting firms. WIRES' principles, its studies, and all public comments are available at www.wiresgroup.com



as 2030, 70 GW to 200 GW of new electric generation will be needed to meet the estimated demand growth. Recent trends indicate that new electric generation will continue to migrate away from fossil resources and toward renewable resources and natural gas. Based on these estimates, the report states that transmission investment must continue to grow from an average of \$15 Billion annually today to as much as \$22 Billion per year in 2030. As electrification expands, the U.S. will require up to \$40 Billion in new investment annually between 2031 and 2050 to ensure that the grid is robust, flexible, capable of maintaining high levels of reliability, and resilient against emerging threats.

Despite transmission's current and future benefits, the grid faces difficult challenges. Major transmission projects require 10 or more years on average for planning, development, approval, and construction. Given the long-lead time for transmission planning and siting, efforts need to begin immediately to update planning forecasts and prepare for an electrified future. We need to be prepared for this new economy, otherwise increased electricity demand may leave us unprepared to meet customer needs or worse compromise system reliability. We are already in the midst of an investment cycle to upgrade and replace aging and existing transmission infrastructure, much of which dates from the 1960s, 70s, and earlier. To optimize our efforts and achieve cost efficiency, these new assumptions about the future must be incorporated into investment decisions today.

The new Brattle report on electrification therefore offers an optimistic tale – one in which we seize this opportunity to plan our transmission grid to support electrification as cost-effectively as possible. The need for action is clear, but can we seize the opportunity? This report is a state-of-the-art look into a more electrified future. It is now time to prepare for it and the technical and economic challenges it will bring.



WIRES solicits and looks forward to your comments and questions, which can be submitted to www.wiresgroup.com or contact@wiresgroup.com

A handwritten signature in blue ink that reads "Brian Gemmell".

Brian Gemmell

National Grid
WIRES President 2019

A handwritten signature in blue ink that reads "James J. Hoecker".

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The Coming Electrification of the North American Economy

Why We Need a Robust Transmission Grid

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February 28, 2019

THE **Brattle** GROUP

Notice

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Executive Summary

Over the coming decades, Western economies will become more highly driven by electric power than they are today. As public policies and consumer choices reflect concerns about fossil fuel consumption, and low-carbon technologies continue to develop, a growing share of the economy will rely on low-carbon electricity to fuel cars, to heat homes and businesses, and to provide process heat at industrial facilities. In fact, the energy industry is already changing rapidly in this direction. In the electric sector, technological progress and public policies are driving a shift towards cost-competitive renewable generation. One example is that Xcel Energy is reducing its emissions by 80% by 2030 and fully decarbonizing its fleet by 2050. A second one is the announcement by Florida Power & Light that it plans to install 30 million solar panels by 2030 in a state without renewable energy standard or carbon emissions goals.

In the broader economy, electrification of sectors currently “powered” by fossil fuels is becoming more prevalent. For example, there are now one million electric vehicles on the road in the United States and the Edison Electric Institute (EEI) forecasts 7 million by 2025. Vehicle manufacturers have announced over 60 new electric light-duty models, released several electric commercial vans, begun to develop electric pickup trucks and semi-trucks that may be available in the early 2020s, and in some cases announced plans to phase out the production of all internal combustion engine vehicles. Electric heat pumps, which are already common in moderate climates, are becoming cheaper and more efficient in colder climates. And advances in technology could even make electrifying industrial processes increasingly possible.

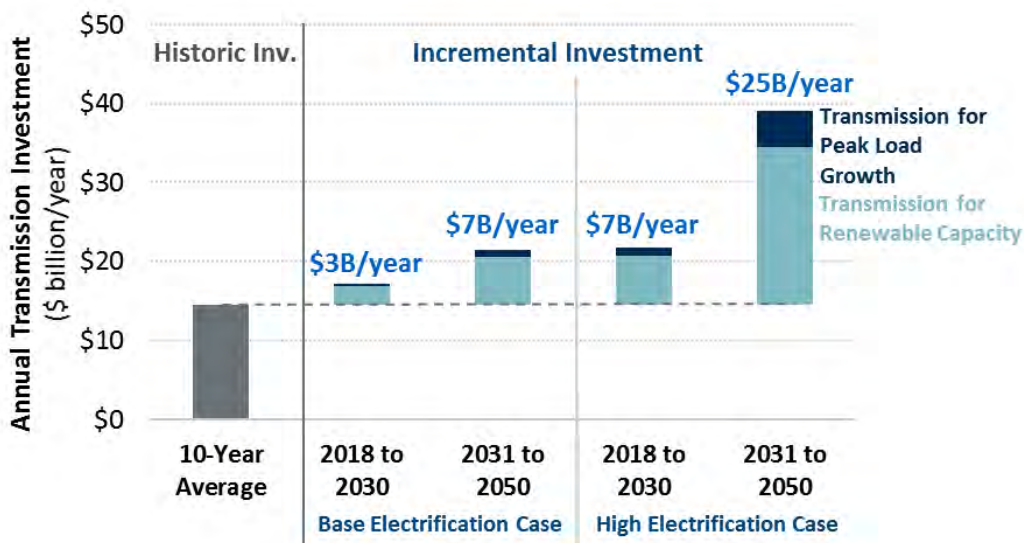
Electrification of these sectors could significantly increase electricity demand. To meet this rising demand, additional low-carbon electricity generation resources will need to be built and supported by adequate and robust transmission and distribution infrastructure.

These developments pose sizeable challenges to the existing patchwork of power systems primarily built to provide reliable electricity at the local or sub-regional level and require a broader view of the role of the bulk power system. This study seeks to provide insights into whether the electric grid will be able to support the transition to a low-carbon future and the extent to which additional and forward-looking investment in electric infrastructure will be necessary.

The report finds that **\$30–90 billion dollars of incremental transmission investments will be necessary in the U.S. by 2030 to meet the changing needs of the system due to electrification, with an additional \$200–600 billion needed from 2030 to 2050.** These investments will be in addition to the investments needed to maintain the existing transmission system and to integrate renewable generation built to meet existing load. Figure ES-1 shows that this level of investment is equivalent to \$3–\$7 billion per year on average through 2030, a 20–50% increase over annual average

spending on transmission during the past 10 years; and \$7–\$25 billion per year on average between 2030 and 2050, a 50–170% annual increase in transmission investment.¹

Figure ES-1: Annual Incremental Transmission Investment due to Electrification



Notes: The historical average reflects transmission investments from 2006 to 2016 based on transmission capital expenditures reported on FERC Form 1.

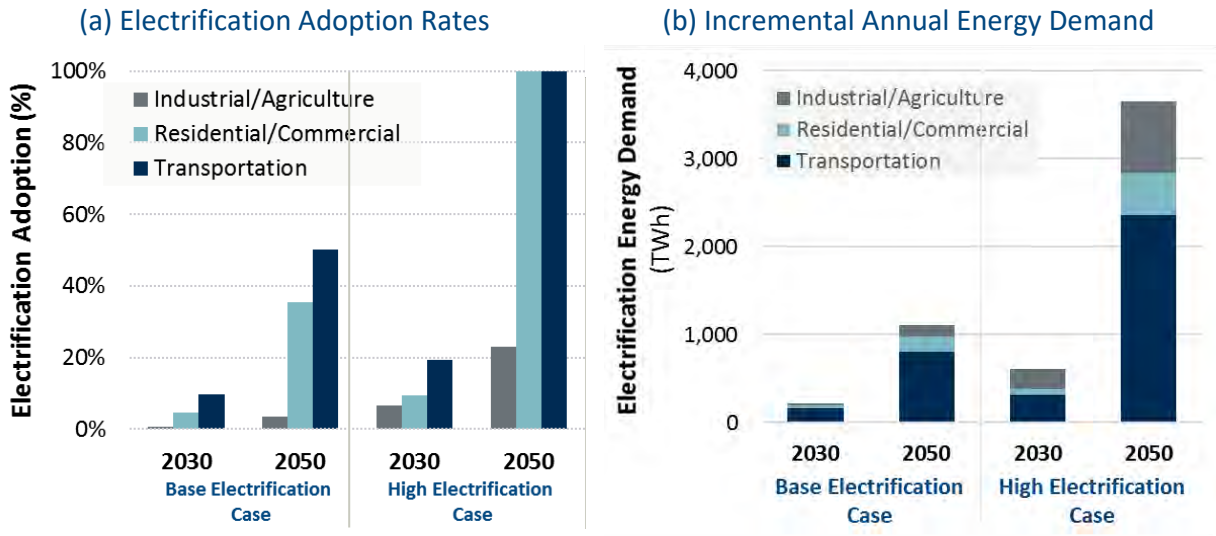
Two primary factors drive the need for more transmission infrastructure in an electrified future: (1) connecting additional renewable generation resources to serve the total energy demand; and (2) ensuring that the electricity system remains reliable with increasing peak demands. Both drivers depend on the pace and scale of the adoption of electrification across the economy.

By 2030, electrification could increase nationwide annual energy demand by 5% to 15% (200 to 600 TWh) and by 25% to 85% (1,100 to 3,700 TWh) by 2050, as shown below in Figure ES-2.² For these projections to materialize by 2030, the current momentum towards EVs continues to accelerate and heat pumps become a competitive space heating technology in certain markets. Between 2030 and 2050 electric transportation becomes the dominant transportation technology and heat pumps penetrate a significant portion of the housing stock. The high electrification case assumes that electrification “powers” all transportation and space and water heating needs by 2050.

¹ The 10-year historical average of transmission investment of \$14.6 billion per year is within the range of earlier projections of \$12–\$16 billion per year through 2030 that did not consider rising electrification demand. Pfeifenberger and Hou, *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, May 2011.

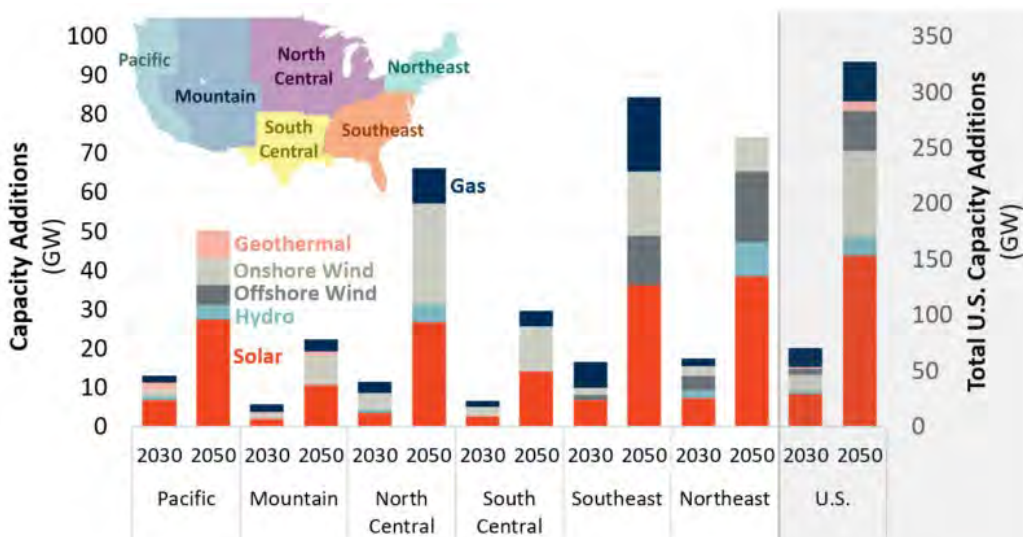
² The projected increase in electricity demand accounts for steady improvements in EV efficiency and expanded investments in energy efficiency in buildings currently served by fossil fuels, reducing energy demand by 1% per year through 2050.

Figure ES-2: Projected Electrification Demand



The mix of new generation resources serving electrification-related demand will differ by region due to differences in resource availability, technology costs, and policy objectives, as shown in Figure ES-3. Overall, 70 GW to 200 GW of additional new power generation will be necessary by 2030 to meet the additional electrification related demand, assuming a 75% share of renewable resources and a 25% share of natural gas-fired resources. A high share of renewables is consistent with a recent trend towards utilities, states, and consumers increasingly choosing low-cost renewable generation to meet rising load, to reduce costs, or to replace emitting resources like coal and gas fired generation. This trend will likely be more pronounced in certain regions such as the Pacific West and Northeast. Assuming that the share of renewable generation further increases to 90% by 2050, an additional 200 GW to 800 GW of generation resources need to be built between 2030 and 2050 to meet the anticipated incremental electrification demand. These generation additions are incremental to the new resources that will replace generation from existing power plants or to meet the load growth of traditional electricity end-uses.

Figure ES-3: Base Electrification Case Incremental Supply Resource Mix (GW)



Notes: Incremental hydro is primarily expected to be imported hydro from Canada.

While distributed solar photovoltaic (PV) generation may meet some of the incremental load, most of the incremental renewable generation will likely be utility-scale solar and wind generation. A recent NREL assessment indicates that even if solar panels were installed on every single appropriate building across the country, they would meet about 40% of the current electricity demand.³ Since anything near full realization of this technical maximum potential for distributed solar PV is very unlikely to be achieved, a realistic build-out of distributed solar PV will at most displace a portion of the existing generation resources. Sources of growing demand, such as from electrification, would then need to primarily be met with utility-scale resources located further away from load centers. In addition, local resources like distributed solar PV in most cases are not substitutes for transmission and will still rely indirectly on the high-voltage transmission system due to their variable nature and the mismatch between the timing of their generation and electricity demand.⁴

While these incremental transmission investments are substantial relative to historic investment levels, **the resulting impact on customer rates is likely very modest or even beneficial** for three reasons: (1) transmission costs represent a small share of customer rates; (2) the total transmission investment will be spread over greater electricity demand with electrification; and, (3) the higher costs of transmission are likely to be offset by lower generation costs. In fact, the 20–50% increase in transmission spending projected by 2030 represents only a 1–4% increase in rates on a per kWh basis before accounting for offsetting savings in generation costs. By enabling access to lower-cost, non-local renewable energy resources, generation costs could be lower by about 2–5%. Since the cost of generation counts for the largest share in customer rates, the additional spending on transmission could result in a reduction in customer rates.⁵

These savings can only materialize, however, if the transmission system is built out in anticipation of the rising demand from electrification of various sectors and the associated need for renewable generation additions. **This scale of transmission needs and the long lead times for transmission investments highlight several important takeaways for transmission planners and policymakers:**

- It is increasingly important for policymakers that set clean energy and decarbonization goals to gain an appreciation for: (1) the transmission system investments that will be necessary to cost effectively achieve these goals and (2) the potential risks of coming up

³ Gagnon, *et al.*, *Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment*, NREL/TP-6A20-65298, January 2016, Table ES-1.

⁴ Frayer, *et al.*, *The Truth about the Need for Electric Transmission Investment: Sixteen Myths Debunked*, Prepared for WIRES Group, September 2017, pp. 18-19. Available at: <http://wiresgroup.com/new/wires-library/wires-reports/>

⁵ The regional and interregional transmission investments are likely to provide other benefits that will reduce customer costs, such as reducing resource adequacy needs through regional and interregional load diversity. For a summary of the economic benefits of transmission investments, see: Chang, *et al.*, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, July 2013.

short on achieving those goals, or doing so at higher costs to the consumer, by moving too slowly on upgrading the transmission system.

- Transmission planners will need to start anticipating the impact of electrification and integrate it into their transmission planning processes.⁶ This is particularly important in the Pacific West and the Northeast—the regions with higher concentrations of first adopters of electric vehicles and more immediate, more ambitious policy targets.
- Transmission planners will need to adapt their analyses to account for the uncertainty in the timing, location, and scale of the adoption of electrified loads and the addition of renewable resources. Adding transmission in anticipation of load growth can be seen as an insurance policy against the alternative of being unprepared for rising demand and relying on short term and potentially much higher cost solutions that may also be unable to meet emissions mandates.
- Transmission planners should continue to expand their consideration of larger scale interregional, and even national-level, projects in their studies. Transmission upgrades that increase capacity across regions will become more important in an electrified, clean energy future as seasonal disparities in peak loads and renewable generation patterns become more significant and the diversification of load served by the renewable generation becomes a key component of integrating clean resources.

Because charging infrastructure is such an important enabler of the electrification of transportation, existing transmission infrastructure could also facilitate the development of highway corridor and urban fast charging stations.

Direct current fast charging (DCFC) is essential to making long-distance trips via electric vehicles feasible. Because fast charging requires large amounts of power, DCFC complexes, especially along highway corridors, will likely become major sources of demand over time with each one representing 5–10 MW of peak demand or more. Connecting loads of this size to the existing distribution system can be time-consuming and require costly network upgrades. Close proximity of transmission infrastructure to convenient locations for DCFC complexes could therefore provide opportunities for cost savings and faster build-out of charging infrastructure.

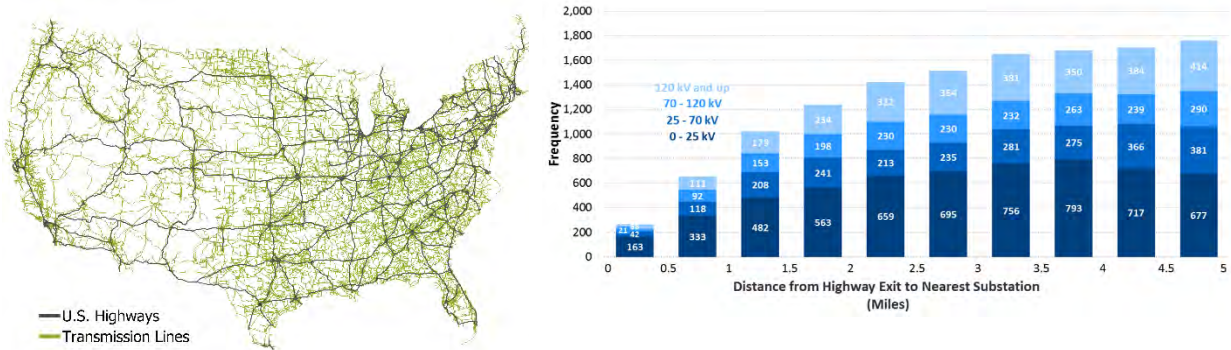
Recent research suggests that 400–800 DCFC complexes would be needed to establish an initial network capable of overcoming existing hurdles related to EV adoption if spaced 35–70 miles apart along major highways.⁷ As Figure ES-4 shows, there are about 400 substations with transformers of 69kV or less located less than a mile away from highway exits. These locations are potential candidates for siting a DCFC complex that is conveniently located within close proximity to

⁶ Adopting “anticipatory” transmission planning has been estimated to save \$30–70 billion in total generation and transmission investment costs across the U.S. by 2030. Pfeifenberger and Chang, *Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future*, June 2016.

⁷ Wood, *et al.*, *National Plug-In Electric Vehicle Infrastructure Analysis*, Office of Energy Efficiency & Renewable Energy, September 2017, p. vii.

highway corridors. Approximately 1,500 more are located less than two miles from such a transformer. Additional opportunities exist at existing highway rest areas. Locating fast chargers at these locations will allow the existing transmission assets to play an important role in facilitating the rapid and comprehensive build-out of the infrastructure needed to facilitate the transformation of the transportation system towards electric vehicles.

Figure ES-4: Transmission and the Highway System



Determining the locations best suited for developing DCFC stations along highway corridors requires a more in-depth, location-specific analysis, including whether or not particular existing transmission assets have spare capacity, existing rights of way, potential for permitting issues, or whether connecting to a local distribution network could be a lower cost alternative. Even in cases where connecting to the local distribution network is more cost effective than connecting directly to the transmission system, taking into account suitable local transmission infrastructure when choosing the location of fast charging sites may provide opportunities for lowering the cost of developing and interconnecting DCFC complexes.

Finally, existing transmission infrastructure could facilitate the development of DCFC infrastructure in urban areas. However, opportunities there likely depend more on the specific transmission infrastructure and DCFC charging requirements in each city in question.

Overall, transmission will play a critical role as the economy moves toward electrification of various end-uses. Transmission investments will be needed to connect cost-effective new renewable generation to serve the additional electrification-related demand. Further, the existing transmission infrastructure can be leveraged to more cost-effectively support the development of fast-charging infrastructure along highway corridors and perhaps in some urban settings. The analysis shows that a robust transmission infrastructure can reduce the cost and speed up the transition to an electrified transportation future.

I. Introduction

The energy industry, and in particular the electricity industry, is in the middle of a fundamental transformation. In the United States, the discovery of vast amounts of shale gas combined with renewable energy deployment, coal plant retirements, and decarbonization policies have been the main drivers behind this transformation. Given the sustained low natural gas prices and the abundant low-cost renewable energy potential in different regions—onshore wind in the middle of the country, solar in the Southwest, and offshore wind on the coasts—this shift will likely intensify over the coming decades and, with it, the need to rethink where transmission is needed to cost effectively serve future electricity customers. In the past, WIRES has explored the implications of these developments for the role that transmission will likely play as the electric sector shifts towards increasing reliance on large-scale renewable resources located far away from load centers; various WIRES reports have also documented the need for more “anticipatory” transmission planning approaches to address these developments more cost effectively.⁸

There are now emerging several additional contributors to the transformation of the energy and electricity system over the coming years and decades. Driven by policy concerns about greenhouse gas emissions, technological and business model progress, and strategic economic development objectives, the portions of the broader economy that have historically relied on the direct use of fossil fuels are also beginning to undergo fundamental change. These trends will likely result in electrification—*i.e.*, the use of electricity rather than the direct use of fossil fuels—of some end-uses even before considering whether electrification is the most cost-effective way to also achieve significant greenhouse gas emissions reductions.

This change is most pronounced in the transportation sector. The declining cost and broader selection of electric vehicles available, new business models around the sharing economy, and advances in autonomous driving technology provide the possibility that the internal combustion engine may soon be replaced with electric drive trains in many transportation applications. Most obvious among these is the arrival of electric vehicles of all sorts, ranging from passenger cars to school and transit buses and commercial fleets, with the potential for electrification of other forms of transportation including ferries and eventually even airplanes.⁹

⁸ See for example: Pfeifenberger and Chang, Well-Planned Electric Transmission Saves Customer Costs: Improved Transmission Planning is Key to the Transition to a Carbon-Constrained Future, Prepared for WIRES, June 2016. This and other WIRES reports can be found here: http://www.wiresgroup.com/wires_reports.html

⁹ In Norway, a ferry operator has successfully introduced an all-electric ferry (See <https://electrek.co/2018/03/05/all-electric-ferries-battery-packs/>, accessed January 8, 2019) and the

Electrification of other fossil-fuel-consuming (and greenhouse gas emitting) sectors such as space and water heating of buildings, agriculture, and industry are also technically possible. However, the extent to which electrification occurs in these sectors over the coming decades will likely depend more significantly on the strength and direction of federal, state, and local public policies targeting economy-wide greenhouse gas emissions reductions than on consumers' preferences.

Increasingly the distinction is made whether electrification is “beneficial” or not, in the sense of lowering the social cost of energy-related services to consumers and society.¹⁰ This report is agnostic as to whether electrification is “beneficial” in the somewhat narrow sense of lowering societal and consumer costs or whether it may simply occur as a result of shifting consumer preferences.

In either case, electrification of these sectors could significantly increase the use of electricity over the coming decades.¹¹ An increase in demand in combination with further additions of renewable resources to supply the incremental demand would further increase the role of transmission in delivering low-cost and reliable electricity to consumers in the future. While there has also been a trend towards more distributed forms of generation,¹² transmission is likely to play an important role in enabling the transition to greater levels of electrification both because the amount of electricity that can be provided from distributed resources is likely insufficient (and less economical) than utility-scale resources and because transmission will increasingly be needed to integrate various loads and supply resources across load centers and regions regardless of whether those supply resources are utility-scale or distributed.

The first part of this report explores the scale of transmission investment that will likely be necessary in a world with increasing electrification. Specifically, it estimates how much

airport operator has announced that by 2040 all short-haul flights leaving Norway will be electric. (See <https://www.theguardian.com/world/2018/jan/18/norway-aims-for-all-short-haul-flights-to-be-100-electric-by-2040>, accessed January 8, 2019). For an overview of developments related to commercial electric aircraft, see: <https://techcrunch.com/2018/07/08/the-electric-aircraft-is-taking-off/> (accessed January 8, 2019).

¹⁰ See for example the definition by EESI: “Beneficial electrification (or strategic electrification) is a term for replacing direct fossil fuel use (*e.g.*, propane, heating oil, gasoline) with electricity in a way that reduces overall emissions and energy costs.” Environmental and Energy Study Institute, Beneficial Electrification, <https://www.eesi.org/projects/electrification>, accessed February 25, 2019.

¹¹ For an analysis of the potential impacts of electrification on electricity demand and greenhouse gas emissions, see Weiss *et al.*, Electrification: Emerging Opportunities for Utility Growth, The Brattle Group, January 2017. Available at: http://files.brattle.com/files/7376_electrification_whitepaper_final_single_pages.pdf

¹² This trend is due to the shrinking cost gap between distributed and utility-scale solar PV, the possibility that distributed resources provide some other local benefits, and policy mandates and building codes that, at least in some states, will likely continue to support the development of distributed resources. In some case, such as is now the case in California, distributed energy resources such as rooftop solar may even become mandated elements of new construction.

electrification may occur in various regions of the United States, how much incremental energy demand and peak load this electrification could entail, the incremental capacity of renewable and gas-fired resources necessary to meet higher demand, and, finally, how much transmission may be needed to support this transformation.

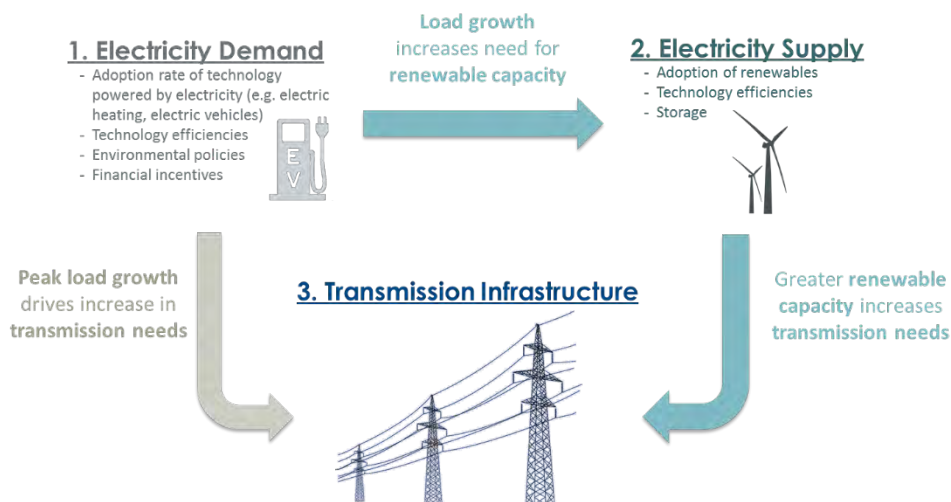
The second part of this report examines how transmission might enable the deployment of fast-charging infrastructure that is likely to be a critical component of a transportation system that initially overcomes range anxiety and charging anxiety and ultimately supports a large-scale electrified transportation system. While identifying the best locations for fast-charging infrastructure on a local or regional basis will require more detailed analysis, the analysis highlights important overlaps between the transmission and highway/urban infrastructure systems with the goal of identifying the opportunities provided by the existing infrastructure to develop the fast-charging infrastructure needed to support the growth (and ultimate volume) of electrified transportation quickly and cost-effectively.

II. Transmission to Support Electrification

The potential scale of transmission investments is directly related to the magnitude of the impacts of electrified end-uses on the total demand for electricity and potential changes to peak demand by region. This study addresses two potential electrification scenarios for six regions—a “Base Electrification Case” that captures a realistic outlook for the potential scale of electrification in 2030 and 2050 based on current technology and policy drivers—and a “High Electrification Case” that represents a more heavily policy-driven scenario that significantly reduces GHG emissions nationwide through electrification. The analyses use reasonable assumptions about the potential speed and depth of electrification of various end-uses in six distinct regions of the United States by 2030 and 2050, the regional supply mix that would meet this incremental electricity demand, and finally how much transmission may be needed to support this incremental electricity supply. There are key considerations in developing an estimate of the incremental transmission investments that will be necessary in the future and develop a range of estimates that account for these key uncertainties.

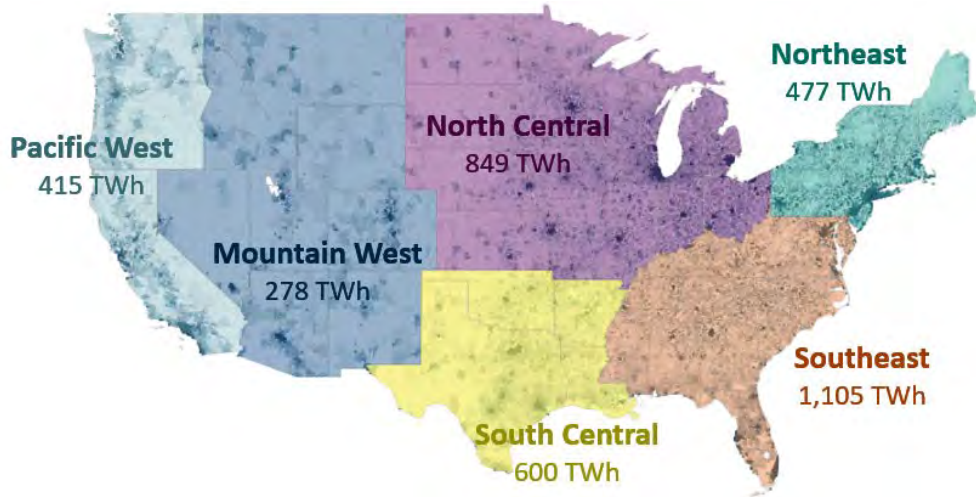
Analyzing the potential need for transmission in a more electrified future required a three-step approach outlined in Figure 1 below.

Figure 1: Transmission Needs Modeling Approach



Recognizing that there is likely to be variation across different regions of the U.S. in the speed and depth of electrification and the type of supply resources likely built to meet incremental electricity demand, each of these three steps was implemented separately for the six regions shown below in Figure 2.

Figure 2: Modeled U.S. Regions with 2017 Electricity Sales



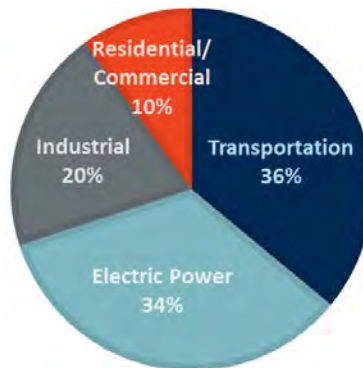
Source and notes: Electricity sales from EIA (Form EIA-861). Underlying map from S&P Global Market Intelligence. Darker shading indicates areas with higher population density. Pacific West includes Hawaii and Alaska (not shown in map).

Next follows a summary of each component of the analysis and of the major assumptions made when developing estimates of the incremental transmission needs in an electrified future. These topics are discussed in additional detail in the technical appendix at the end of this report.

A. Electrification-Related Demand

Electrification of transportation, residential and commercial buildings, and industry will likely occur based on changes in the cost and performance of alternatives to the current technology, changing consumer preferences and, in many states, the need to implement mandatory and economy-wide state level decarbonization targets. Figure 3 below shows that as of 2017 U.S. carbon dioxide emissions are split between the transportation sector (36%), electric power sector (34%), industrial sector (20%), and the residential and commercial building sector (10%). While electric sector emissions have fallen by 25% since 2005, emissions levels have remained relatively flat in the other sectors.

Figure 3: U.S. Energy-Related Carbon Emissions by Sector (2017)



Source: EIA, Annual Energy Outlook 2018, Table 18 (U.S. Energy-Related Carbon Dioxide Emissions by Sector and Source).

The dynamics of electrification adoption, like the adoption of all new technologies, are likely to be characterized by hard to predict tipping points that result in rapid and widespread changes in consumer preferences and exponential growth once a certain tipping point is reached. The reliability and cost implications of a surge in electricity demand due to electrification require that transmission planners consider 5 to 10 years into the future when and where electrification load may materialize on their system without a reliable forecast of how rapidly electricity demand may increase.

Based on The Brattle Group's proprietary electrification model, *bElectrify*, the study analyzes the key regional drivers of earlier and later adoption of electrification by end-use to project the incremental peak and average electricity demand from electrification in each region of the country identified above. Due to the time required to plan for and build new transmission lines, the study analyzed the potential impacts of electrification on electricity demand in 2030 to demonstrate the levels of electrification that planners likely need to start considering now in their near-term planning studies. The assumptions for 2030 are based on projected costs and performance of various electrified end-uses as well as the strength of regional commitments to GHG policies. The study also includes a long-term outlook for electrification in 2050 to demonstrate the potential levels of investment in transmission that will be necessary as electrification adoption accelerates and states aim to achieve their long-term decarbonization targets. For this reason, the 2050 Base Electrification Case focuses on the long-term decarbonization targets already in place. For both 2030 and 2050, a Base Electrification Case captures a realistic outlook for the potential scale of electrification based on current technology and policy drivers and a High Electrification Case that assumes nearly full electrification will be necessary to achieve deep economy-wide GHG emissions reductions.¹³

¹³ There are significant uncertainties as to the timing and precise changes in the electricity sector that will occur over the coming decades. The assumptions in this report represent a reasonable projection of this transformation. The conclusions of this report would not be fundamentally different if decarbonization proceeds along a somewhat different trajectory.

Direct and indirect electrification pathways

There is still significant uncertainty about both the longer-term technological evolution of competing technologies as well as the ability and cost of various decarbonization pathways. For example, while battery electric vehicles (BEVs) seem to be gaining momentum in the light duty vehicle (LDV) segment, *i.e.* for passenger cars, several manufacturers continue to develop hydrogen fuel cell (HFC) vehicles. Hydrogen is being discussed as a promising transportation fuel for heavy-duty vehicles and other long-distance freight transportation, such as shipping.

There is even more uncertainty about decarbonization pathways for space and water heating and agricultural and industrial emissions. For example, electrifying space heating still poses significant challenges, in terms of the performance of air-source heat pumps in very cold conditions, the cost of the heat pumps, the peak load impact of electrified heating, and the ability to replace existing heating systems in hundreds of millions of structures over a relatively short time horizon. For these reasons, hydrogen is being discussed as a potential alternative decarbonization pathway, assuming that hydrogen can be made in a carbon-neutral fashion. Carbon-neutral hydrogen production can be accomplished either by using natural gas as a feedstock and then capturing and sequestering the CO₂ emissions during steam reforming, or by using water electrolysis and renewable energy to generate hydrogen directly from water.

There are significant cost and technology risks associated with carbon capture and sequestration as well as with electrolyzing hydrogen from non-emitting electricity so that it is unclear what role either of these two “hydrogen pathways” will play in the decarbonization of various end-uses. It is important to note, however, that the electrolysis pathway would in essence be a form of indirect electrification since the hydrogen itself would be made from electricity. Given the relative efficiency of direct electrification, say in the form of a heat pump, and indirect electrification via hydrogen electrolysis, the hydrogen electrolysis electrification path would actually lead to significantly higher electricity needs—perhaps 2.5 to 5 times more—than direct electrification. On the other hand, since hydrogen can be stored for longer periods, the hydrogen via electrolysis pathway would likely create significantly more flexibility and hence would likely have different peak load implications.

This study assumes direct electrification. Given the possibility that some end-uses may be indirectly electrified, for example via water electrolysis of hydrogen, the estimates of electricity demand impacts presented here could well be conservative, even compared to the high electrification scenarios.

1. Transportation Electrification

Adoption of electric vehicles in the transportation sector is shifting from being driven by early adopters and policy prescriptions, primarily in the form of state-level Zero Emissions Vehicles (ZEV) mandates (which will require over 3 million EVs on the road by 2025) to the purchase of electric vehicles based on cost effectiveness and consumer preferences enabled by a much wider availability of lower cost electric models. Consumers will increasingly have more options for purchasing EVs at a lower premium to conventional vehicles as automakers roll out over 60 EV models by 2025. For example, GM announced that they will offer at least 20 EVs by 2023 and are committed to an “all-electric future.”¹⁴ And on costs, Bloomberg New Energy Finance predicts that the upfront costs of midsize EVs will become competitive with conventional vehicles on an

¹⁴ Jamie. L. LaReau, “GM plans expanded Bolt production, 20 new electric vehicles by 2023”, *Detroit Free Press*, June 12, 2018. Available at <https://www.freep.com/story/money/cars/general-motors/2018/06/12/gm-plans-expanded-bolt-production-20-new-electric-vehicles-2023/685108002/>

unsubsidized basis starting in 2024 due to the declining cost of batteries alone.¹⁵ In addition, the shift towards transportation services will result in a higher utilization of vehicles, including ride-hailing services and autonomous vehicles, and will tend to shift vehicle purchases towards the lower operating costs of EVs even if the vehicle costs are somewhat higher.¹⁶ Finally, the analysis considered the growing adoption of commercial electric vehicles, the development and testing of electric tractor-trailers, and the recent adoption and announcement of electric transit bus fleets.

Current trends and the most recent projections of the growing EV market share support a base case assumption of a 10% penetration of electrified transportation by 2030 (on a vehicle-miles-travelled basis) and 50% penetration by 2050. The analysis assumes penetration of electric light-duty vehicles (11%) in 2030 outpaces penetration of medium-duty (7%) and heavy-duty vehicles (5%). To put these values into context, achieving a 10% penetration in the transportation sector in 2030 will require that the annual market share of light-duty EVs rises from about 1–2% today to nearly 40% in 2030 resulting in a total of 35 million of light-duty EVs on the road. Further ahead in 2050, a 50% penetration translates to about 160 million electric LDVs on the road. While this scale of EV adoption is much higher than today, it will likely be insufficient to meet the long-term decarbonization targets set by many states. For that reason, a high scenario is also analyzed, in which adoption rates are twice as high as the base assumptions: 20% in 2030 and 100% in 2050. Adoption of EVs should increase faster in the regions currently leading in EV sales, have set ZEV mandates, and/or have carbon reductions goals, as explained in more detail in the appendix.

Translating the number of EVs on the road to electricity load requires projecting the miles driven by the EVs, the efficiency of the vehicles, and the likely charging profiles based on rate structures and seasonal, weekly, and daily driving patterns. As recent studies on ride-hailing services have shown that vehicle miles travelled (VMTs) for personal transportation increase with the availability of lower marginal cost options, the study assumes that total VMTs will rise by 25% by 2050.¹⁷ Recent analysis by the U.S. Department of Energy, finding that nearly 90% of charging is likely to occur at home, was used to develop load.¹⁸ Based on an analysis of personal vehicle driving patterns, the study identified the periods of the day in which vehicles are likely to park at home

¹⁵ Bloomberg New Energy Finance, *Electric Vehicles Outlook 2018: Global Sales Outlook*, <https://about.bnef.com/electric-vehicle-outlook/>, accessed November 18, 2018.

¹⁶ Weiss, *et al.*, “The electrification accelerator: Understanding the implications of autonomous vehicles for electric utilities,” *The Electricity Journal*, Vol. 30, Issue 10, December 2017. Available at: <https://www.sciencedirect.com/science/article/pii/S1040619017303093>

¹⁷ See Section A.2 of the Technical Appendix for more details on the VMT impacts of lower cost transportation options.

¹⁸ Wood, *et al.*, *National Plug-In Electric Vehicle Infrastructure Analysis*, Office of Energy Efficiency & Renewable Energy, September 2017. Available at: https://www.energy.gov/sites/prod/files/2017/09/f36/NationalPlugInElectricVehicleInfrastructureAnalysis_Sept2017.pdf

or at work and plug in for charging, assuming they are not provided a strong incentive for off-peak charging.

While time-of-use rates and other incentives have shown promise to induce charging to occur during periods less likely to lead to peak impacts, it is unclear how quickly and broadly such rates and incentives will be introduced.¹⁹ While reducing peak load impacts of EVs may somewhat alleviate the need for transmission investment to meet a higher peak demand, it will not limit the need to access and integrate increasing renewable generation to meet the load regardless of when it occurs. It is also possible that shifts towards commercially provided transportation services (such as ride hailing) may increase the demand for charging during peak hours and that the value of charging during peak periods for such services exceeds the cost, even if rates fully reflect these costs. Hence, the willingness to shift charging away from peak periods may decline over time for at least some elements of the transportation system.

Commercial vehicles are assumed to mostly drive during the day, mainly during business hours. Therefore, a significant amount of charging should take place in the evening and at night when commercial vehicles are stationary. The charging load for freight transportation is assumed to be relatively flat with slightly higher demand in off-peak hours as it is unlikely that charging costs will dictate the schedule for long-haul routes, but will reflect the potential for reducing costs by charging overnight.

Finally, vehicle charging will tend to be lower on the weekends and slightly lower during summer peak loads hours based on historical driving patterns.

2. Building Electrification

Unlike with transportation, the primary source of energy demand in the residential and commercial building sectors—space heating and water heating—will likely remain a commodity as heating homes or businesses with a high efficiency electric air-source heat pump provides few consumer benefits beyond potential cost savings and emissions reductions. For that reason, adoption will likely depend on the evolution of the technological capabilities and cost of the appliances and state and federal policies intended to increase heating efficiency and reduce GHG emissions.

Currently the conversion of gas- or oil-fired heating to electric heat pumps is most economically advantageous in regions with new construction, warmer climates, and oil-fired heating systems and buildings that either require replacement of the heating system that previously did not have an air conditioning (AC) system or require both the heating and AC systems to be replaced

¹⁹ For example, see San Diego Gas & Electric's evaluation of its EV time-of-use rate pilot study (<https://www.sdge.com/sites/default/files/SDGE%20EV%20%20Pricing%20%26%20Tech%20Study.pdf>) and EPRI's evaluation of a similar study for Salt River Project (SRP) customers (<http://mydocs.epri.com/docs/PublicMeetingMaterials/ee/000000003002013754.pdf>).

simultaneously. Looking forward, NREL, in its moderate advancement scenario, projects that air-source heat pumps will become cost-competitive with existing gas furnaces in the 2030s for most residential cases and by 2050 in cold climates.²⁰ Even then, the adoption of electrified heating is likely to be limited as replacing these systems in existing buildings is a complex process with a low turnover rate and much of the U.S. building stock currently in place will still be in place by 2050. Long-term policy goals are likely to be a more significant factor with the need to drive down building-related emissions to meet long-term targets for reducing greenhouse gas emissions. To meet the 2050 GHG mandates in New York, Minnesota and California, several studies find that over 50% of heating will need to be electrified, with most studies projecting for 60–75% penetration by 2050.²¹

Based on a review of these key drivers, electrification may result in replacement of about 5% of current fuel demand for heating by 2030 and 35% by 2050. This level of adoption would require about 7 million housing units across the U.S. to achieve full electrification by 2030 and 36 million by 2050 under the Base Electrification Case. High Electrification Case assumes building electrification will double to 10% in 2030 and fully electrify in 2050.

While water-heating demand is relatively consistent throughout the year, space-heating demand is heavily concentrated in the winter months and will reach its peak demand on the coldest days of the year. Electrification of heating is thus likely to have a significant impact on the winter peak electricity load and in some cases may switch annual peak load from the summer to winter. The peak demand in each region was calculated assuming a daily load shape for space and water heating based on those developed by EPRI and based on projected daily temperatures in a typical meteorological year and the efficiency of heat pumps at lower temperatures.²²

3. Industrial and Agricultural Electrification

Energy demand in the industrial and agricultural sectors, which accounts for about 30% of total U.S. energy demand and about 20% of U.S. carbon dioxide emissions, is spread across a much more diverse set of applications than in transportation or heating. Energy demand is greatest in several sectors, including chemicals, petroleum and coal products, paper, primary metals, and food that require significant process heat in their industrial processes.

²⁰ NREL, *Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050*, 2017. Available at: <https://www.nrel.gov/docs/fy18osti/70485.pdf>

²¹ For NY, see: VEIC, *Ramping Up Heat Pump Adoption in New York State: Targets and Programs to Accelerate Savings*, Prepared for NRDC, September 25, 2018. For MN, see: Vibrant Clean Energy, *Minnesota's Smarter Grid: Pathways Toward a Clean, Reliable, and Affordable Transportation and Energy System*, July 31, 2018, p. 11. For CA, see: Deason, *et al.*, *Electrification of buildings and industry in the United States: Drivers, barriers, prospects, and policy approaches*, March 2018, p. 31.

²² EPRI, *Load Shape Library 6.0*, 2018. Available at: <http://loadshape.epri.com/enduse>

Alternative electrified approaches to providing similar energy demands are not readily available for most of these applications but could emerge as industrial emissions become a greater focus for meeting long-term decarbonization targets. Two recent studies of nationwide electrification by NREL and EPRI found there is likely to be limited electrification of the industrial sectors unless transformative technological progress can be achieved.²³ Based on these studies, the analysis assumes that less than 1% of industrial demand will electrify by 2030 and 3% will electrify in 2050 in the Base Electrification Case and in the High Electrification Case 11% will electrify by 2030 and 23% by 2050.

4. Incremental Demand

The current trends and future potential for electrification across the economy indicate that the transportation sector will likely be the most significant source of electrification load through 2030 with building electrification tending to increase faster in the 2030 to 2050 timeframe as policymakers focus on the longer-term decarbonization goals and industrial electrification likely requiring significant technological breakthroughs. Figure 4 below summarizes the adoption rates of electrification in the transportation, building, and industrial sectors assumed in the analysis of incremental electricity demand.

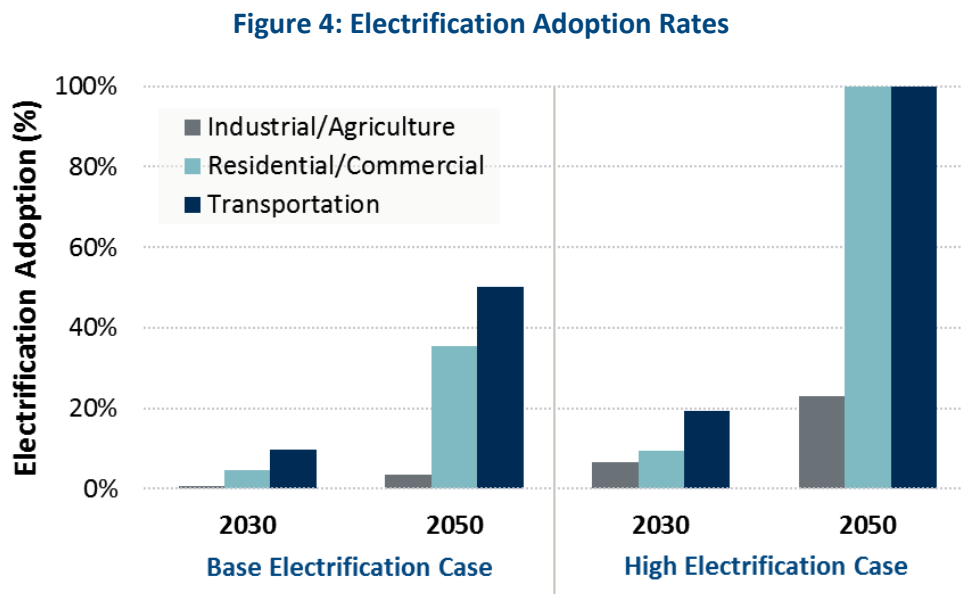
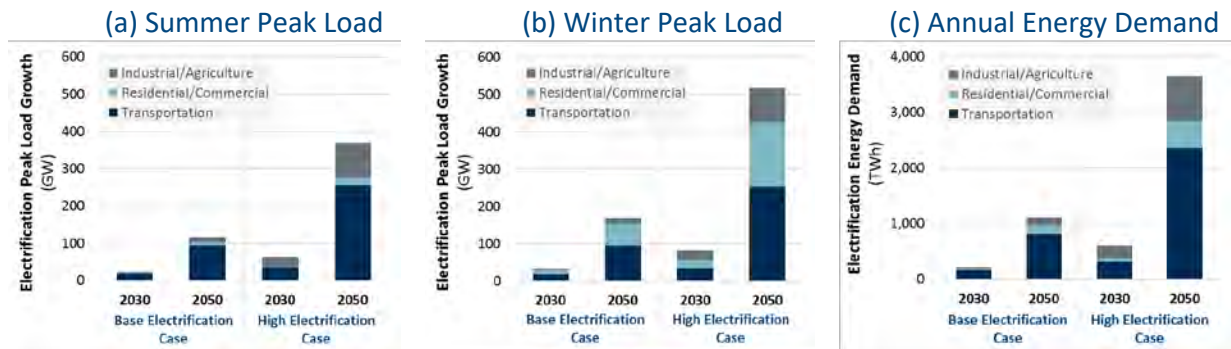


Figure 5 below illustrates the best estimate of the pace of electrification, which will increase annual energy demand nationwide by 5% to 15% (or between 200 and 600 terrawatt-hours (TWh) by 2030 and by 25% to 85% (or between 1,100 and 3,700 TWh) by 2050. Due to the nature of transportation and heating demand, summer and winter peak load impacts of electrification differ significantly. Summer peak load grows by 3% to 10% by 2030 (+20 to 60 GW) and 15% to 50% by

²³ NREL Study: Mai, *et al.*, Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States, 2018. EPRI Study: EPRI, U.S. National Electrification Assessment, April 2018.

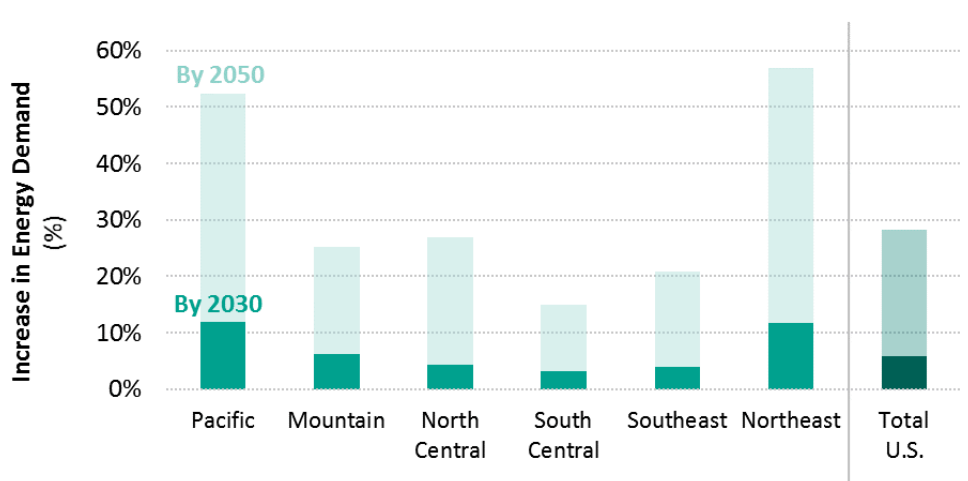
2050 (+120 to 370 GW), primarily driven by EV charging patterns and some water heating load. Winter peak load grows much more rapidly—5% to 10% by 2030 and 25% to 80% by 2050—primarily due to the impact of electrified space heating on system demand during heating season. The regions with the most significant heating load, the North Central and Northeast regions, become winter peaking by 2050 in both scenarios.

Figure 5: Nationwide Incremental Electrification Demand



As explained in detail in the Technical Appendix, the study relies on region-by-region electrification adoption rates for each sector to identify the regions in the country where electrification is likely to have the greatest impact on demand. Figure 6 shows that electrification is expected to have the most significant impact in the Pacific West and Northeast regions, with an 11% increase in energy demand by 2030 and over 50% increase by 2050 under the Base Electrification Case assumptions. These regions set the most aggressive ZEV mandates and decarbonization goals in the country and have the lowest per-capita electricity demand before considering electrification demand due to lower cooling loads. By comparison, the assumed electrification adoption in the other regions results in a lower impact due to less aggressive policies and higher base demand.

Figure 6: Regional Base Electrification Case Incremental Electrification Demand



B. Supply Resource Mix

The future mix of the electricity generation resources is shifting rapidly toward low-cost gas and renewables resulting in significant investment in new gas-fired and renewable generation capacity and retirements of coal-fired plants. Looking forward, this trend is likely to continue and may evolve even more towards renewables as states ramp up their renewable and decarbonization goals mandates, corporations aim to purchase 100% clean generation, and utilities consider the relative costs of new renewable relative to existing coal and gas assets. In addition, electrification provides a clearer path towards meeting decarbonization targets of governments, companies, and consumers if the electricity generated to supply electrified end-use technologies is clean.²⁴ Electrification will therefore drive a greater demand for new renewable generation and cost-effective transmission infrastructure upgrades to access and integrate the highest quality and (likely) the most remotely located renewables.²⁵

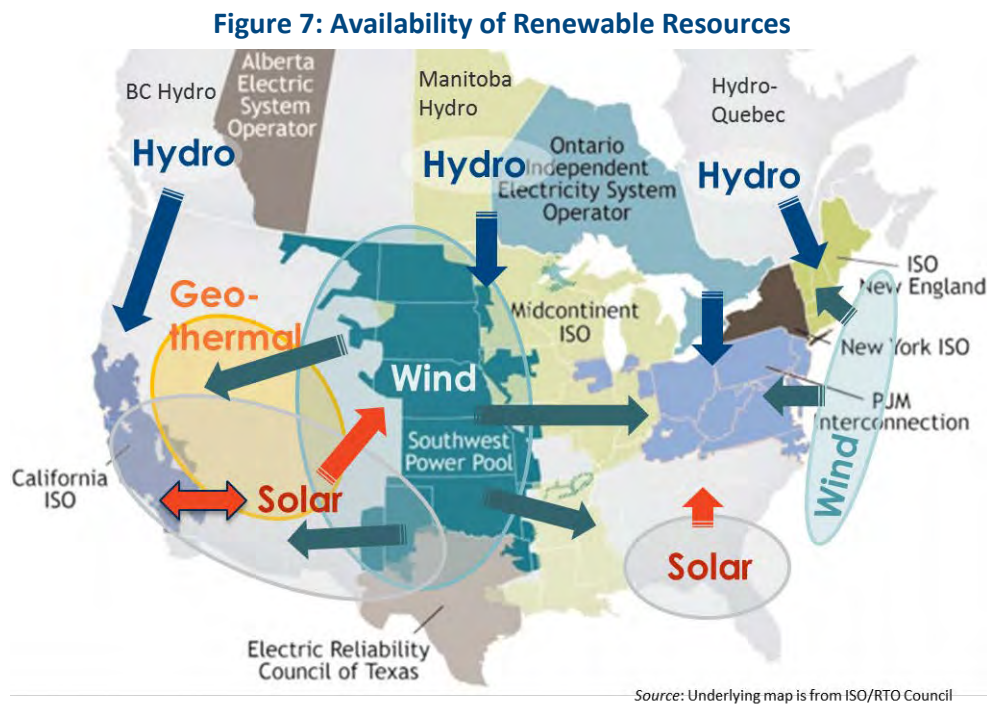
The study estimates the regional supply mix that is likely to meet the incremental electricity demand resulting from each of the regional electrification pathways discussed above. While the precise mix of resources that will be built to meet future demand in different regions and under varying conditions cannot be known, it is less relevant to future transmission investment than the split between fossil fuel-fired and renewable generation resources. Natural gas and other fuel-based power supply tends to be built closer to load centers and existing transmission infrastructure such that long-distance transmission is less of a cost factor in siting fossil-based generation.

For renewable energy resources, however, resource quality and thus the average cost of new resources differs significantly by location. For example, the capacity factor of land-based wind can differ by 30% or more between the locations with the highest quality resources in the central portion of the country and less windy areas, such as the Southeast. Consequently, building transmission to access high quality but distant renewable resources is often more cost effective than making use of more local, but lower quality resources. The recent sharp decline in the capital cost of both renewables and battery storage will alter this equation—by reducing the relative share

²⁴ Due to the higher efficiency of electric heating and transportation relative to heating with gas or driving with gasoline, GHG emissions reductions can be achieved with electrified end-uses even if the power supply is not GHG free. Ultimately, deep decarbonization requires (mostly) eliminating GHG emissions from the electrical generation. This does not mean that the use of liquid or gaseous fuels will be eliminated from the power supply, as long as the net GHG emissions from that fuel is close to zero. This could be accomplished with various types of biofuels and biogas as well as fuels made from renewable energy via water electrolysis.

²⁵ As electricity systems approach 100% carbon free supply, it remains unclear whether variable renewable generation technologies, such as wind and solar PV, coupled with various flexibility options are more cost-effective than “firm low-carbon” resources, such as biogas, hydro resources with large reservoirs, or fossil fuel-fired resources with carbon capture and sequestration. Nonetheless, it seems likely that over the coming decades wind and solar resources will continue to grow significantly. For a discussion of “firm low carbon resources” see Sepulveda *et al.*, “The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation,” *Joule* 2, 1–18, October 17, 2018

of the cost of generation (and local storage) relative to transmission—and the optimal future mix of renewable resource types. But, these trends are unlikely to fundamentally change, at least in the foreseeable future, the attractiveness of accessing large-scale, high quality, and remote renewable resources or the need to diversify the load being served by both remote and local renewable resources. Figure 7 below highlights how access to high-quality renewables differs by geography with each region of the country having access to a unique mix of high quality, low-cost renewable resources.



Notes: Renewable zones based on resource availability maps released by NREL.

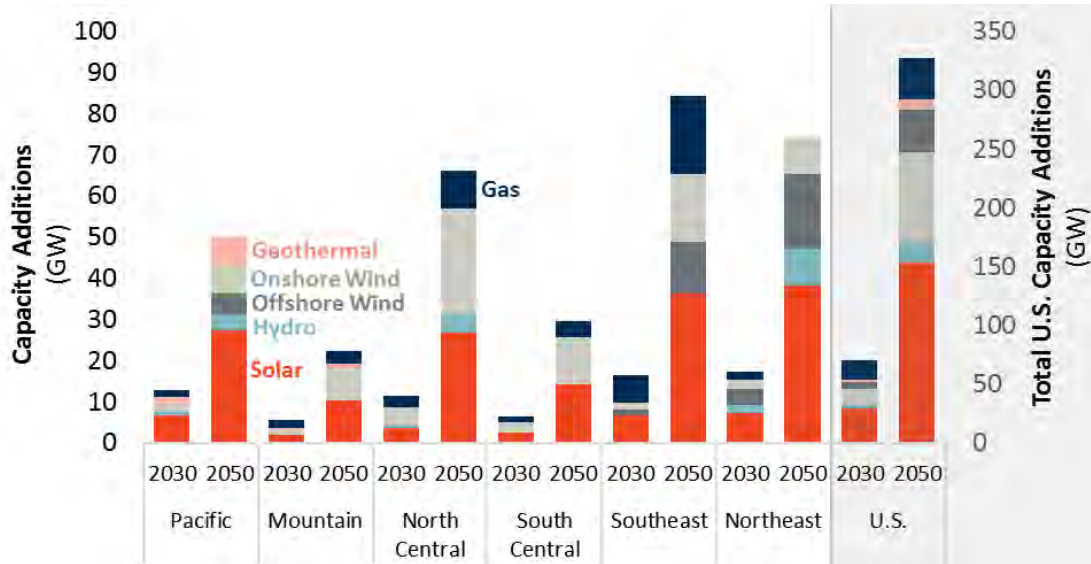
Distributed energy resources, in particular rooftop and community solar PV, are seeing significant growth across the country. Building small, distributed solar PV near load centers tends to be more expensive than building larger scale solar PV in solar rich areas because distributed resources do not benefit from the best solar sites and are built at drastically reduced scale. Distributed local solar PV can provide some benefits as well and the cost difference between larger and smaller scale systems is declining. Some states such as California are beginning to mandate that new houses include solar PV systems. While it is possible that some of the projected incremental demand from electrification will be met with distributed resources, it is equally legitimate to assume that any expected growth in distributed solar PV will primarily displace existing and local fossil generation. A recent report by the National Renewable Energy Laboratory (NREL) estimated that the production from distributed solar roofs, even if such roofs were installed on every single appropriate building, would only be able to meet approximately 38% of *existing* electricity demand nation-wide.²⁶ Since it is highly unlikely that anything near full penetration will be achieved, a

²⁶ Gagnon *et al.*, Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment, NREL/TP-6A20-65298, January 2016, Table ES-1

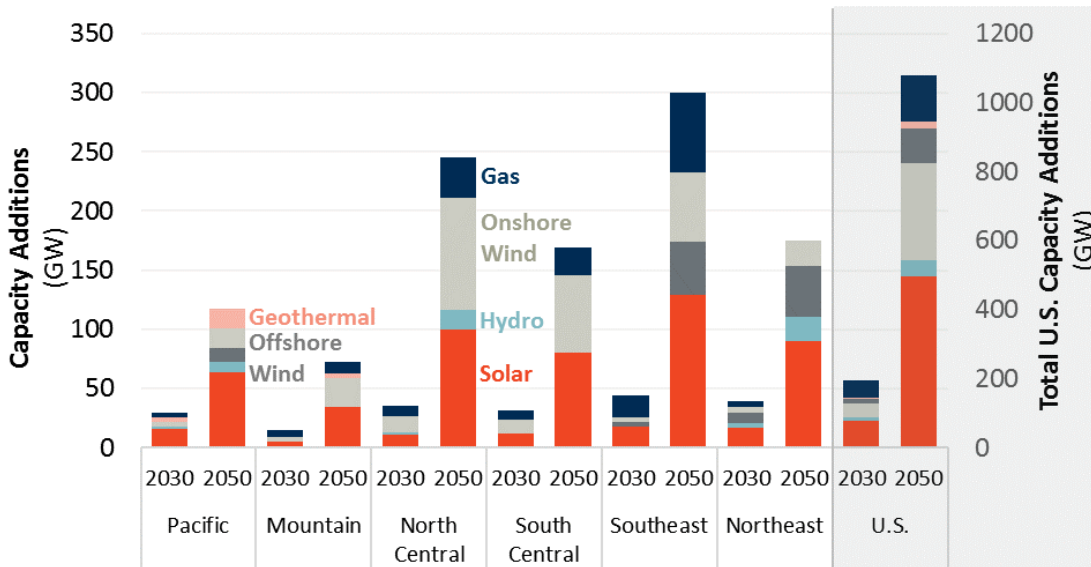
realistic contribution of distributed solar PV to existing electricity demand would be significantly lower and any new demand, such as from electrification, would need to be met with other, *i.e.*, remote resources.

Figure 8: Projected Incremental Renewable Supply by Region

(a) Base Electrification Case



(b) High Electrification Case



While policy still plays an important role in determining the resource mix of new power generation, the evolution of the costs of renewable and storage technologies is already shifting the relative importance of policy and cost. Given the sustained low prices for natural gas and large-scale retirements of coal and nuclear capacity, natural-gas fired generation remains attractive for new generation in many areas. At the same time, renewable resources on their own or coupled with battery storage are beginning to compete in some regions with both new and existing gas-fired generation on cost alone, *i.e.*, before taking into account greenhouse gas or other emissions,

and are likely to become more economically competitive in other regions in the near future. Once policy-driven mandates and procurements are taken into consideration, future power supply in some states will primarily come from a combination of renewables and battery storage, whether to meet increasing load through electrification or to replace retiring existing generation. In other states, it is likely that a preference for at least a portion of new demand being met by natural-gas fired generation will continue to drive investment.

Current cost information and public policies in place imply that electrification will probably require 70–200 GW of new capacity by 2030 and 300–1,000 GW by 2050. Figure 8 above shows the supply resource mix for additional generation needed by region. Renewable resources are assumed to represent about 75% of new generation capacity by 2030, increasing to 90% by 2050. The renewable capacity in each region reflects the total incremental demand due to electrification, the relative size of the region, and the capacity factors for renewables in each region.

C. Transmission Needs for Electrification

The level of future transmission investment will depend on several factors, including the need to replace aging infrastructure and to integrate growing levels of renewable generation. This study specifically focuses on estimating the magnitude of investment to meet an emerging driver of transmission needs: electrification demand.²⁷

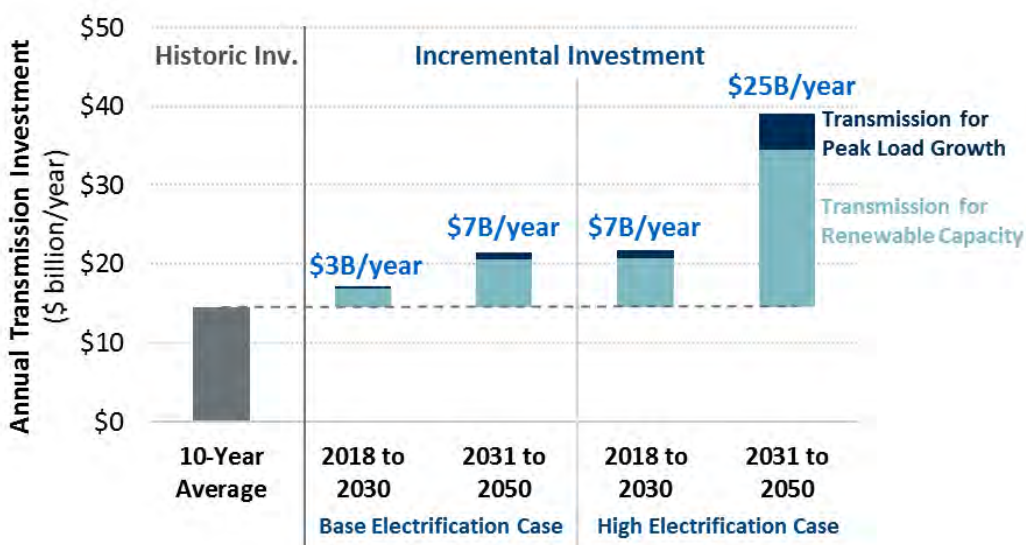
Transmission will primarily be needed with rising electrification demand for two purposes: First, to connect remote renewables to the bulk power system to the extent remote renewables are assumed to deliver incremental energy needs due to electrification; and second, to ensure a reliable power supply by providing sufficient transfer capability as peak demand increases, again due to electrification. A review of historical levels of projected peak load growth and transmission investment supports an estimate that each kilowatt (kW) of peak load growth requires between \$100 and \$400 of transmission investment.²⁸ Actual historical and recently estimated costs of transmission upgrades necessary to access and diversify large-scale renewable resources indicate that each kW of utility-scale renewable capacity added to the system will require transmission investment of between \$300 and \$700. The Technical Appendix provides further details on the development of these estimates.

²⁷ Detailed modeling of individual transmission projects was beyond the scope of this report.

²⁸ Changes in peak load are used as a proxy driver of transmission investments to maintain reliable power supply. Even though transmission flows may not be at their maximum during peak load conditions, transmission has traditionally been built to meet peak load, especially in areas without sufficient local generation. While this traditional rationale may not be as applicable in an electricity system evolving both towards more distributed and more remote (renewable) generation sources, it is likely that transmission will continue to be cost-effective and necessary to meet changing load shapes including increasing peaks.

To connect these additional resources and to serve rising electrification demand, \$30–90 billion dollars of additional transmission investment would be necessary by 2030 and \$200–600 billion by 2050. Figure 9 below shows that this level of investment is equivalent to \$3–\$7 billion per year on average through 2030, a 20–50% increase relative to annual average spending over the past 10 years; and \$7–\$25 billion per year on average between 2030 and 2050, a 50–170% annual increase over the past 10 years.²⁹

Figure 9: Incremental Annual Transmission Investment due to Electrification



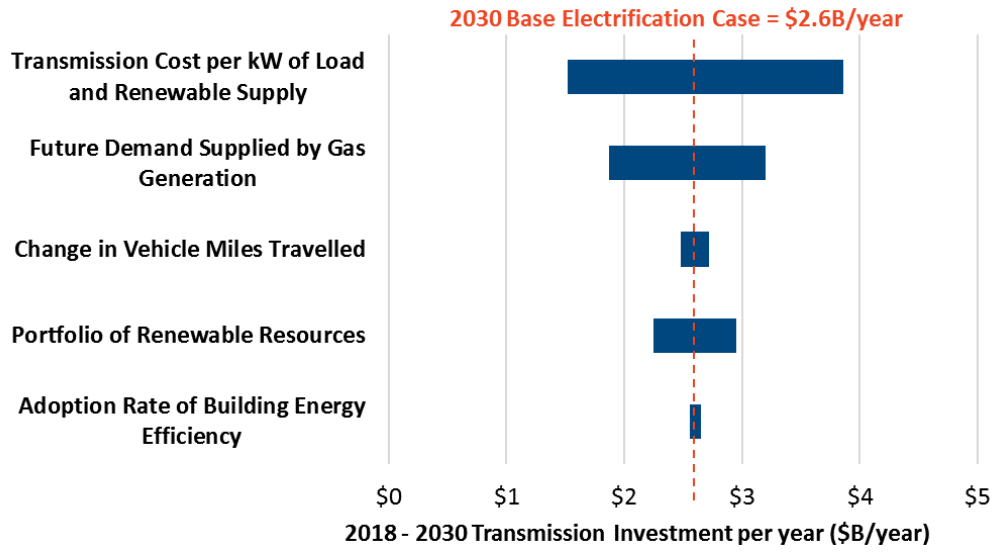
Notes: The historical average reflects transmission investments from 2006 to 2016 based on transmission capital expenditures reported on FERC Form 1.

Projecting long-term transmission needs requires considering a range of potential market conditions and outcomes. Figure 10 below shows that the annual investment will also vary based on the estimated level of transmission investment per kW of peak load or renewable capacity, the percentage of future demand met by gas-fired versus renewables resources, and changes in the future level of VMT or energy efficiency efforts. The sensitivity assumptions are shown in Table 1 below. In both 2030 and 2050, the most consequential assumptions are the level of transmission investment required to serve the electrification load and the percentage of load met by gas supply. The lower end of the range (\$1.5 billion per year through 2030 and \$4.0 billion per year from 2030 to 2050) likely represents a future in which renewable generation and storage costs continue to fall, which reduces the cost effectiveness of building transmission to access the most remote renewable resources and to diversify the load served by renewables.

²⁹ The 10-year historical average transmission investment of \$14.6 billion per year is similar to projections of \$12–\$16 billion per year through 2030 that did not consider electrification demand. Pfeifenberger and Hou, *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, May 2011. Available at: http://files.brattle.com/files/6534_employment_and_economic_benefits_of_transmission_infrastructure_investment_pfeifenberger_hou_may_2011_wires.pdf

Figure 10: Sensitivities for Base Electrification Case

(a) 2030



(b) 2050

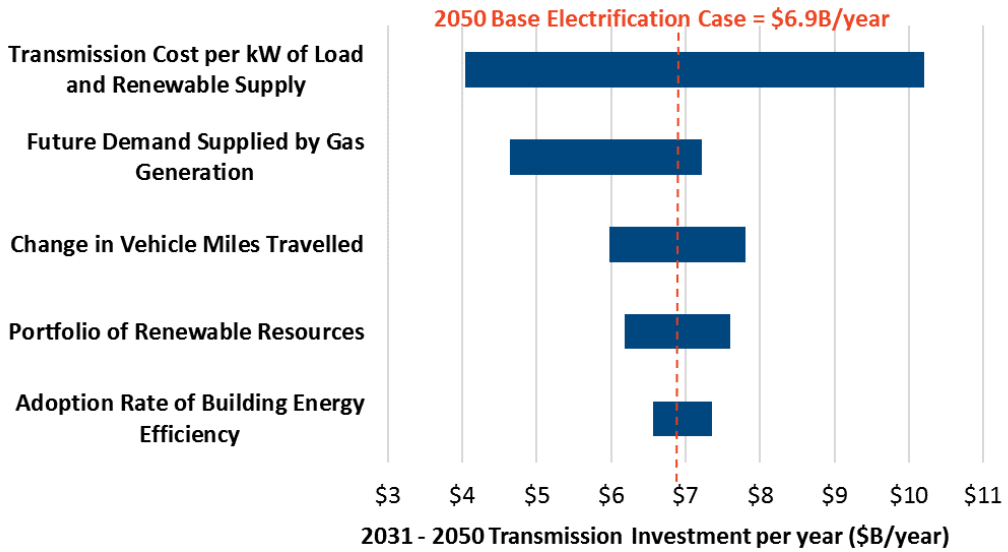


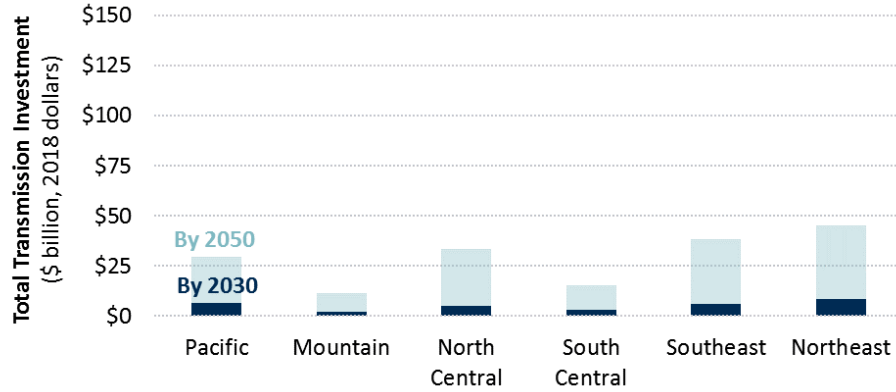
Table 1: Sensitivity Assumptions

	Low Assumption	Reference Assumption	High Assumption
Transmission Costs	Renewables: \$300/kW Peak Load: \$100/kW	Renewables: \$500/kW Peak Load: \$200/kW	Renewables: \$700/kW Peak Load: \$400/kW
Future Demand Supplied by Gas	50% of demand supplied by gas-fired generation	Base Assumption (see Table 6)	0% of demand supplied by gas-fired generation
Change in Vehicle Miles Travelled (VMT)	0% increase by 2050	25% increase by 2050	50% increase by 2050
Portfolio of Renewable Resources	Decrease solar generation by -20%	Base Assumption (see Table 6)	Increase solar generation by +20%
Building EE Adoption	No incremental EE	Additional 1%/year above 2018 AEO assumption	Additional 2%/year above 2018 AEO assumption

The total transmission investment needed due to electrification will be spread across the country as shown in Figure 11 below. About half of the total investment by 2030 will be in the Northeast (\$7 billion) and Pacific West (\$9 billion). Investment needs would be smallest in the Mountain West and South Central regions due both to their small size (in terms of electricity demand) and limited decarbonization policies.

While substantial in absolute terms, these transmission investments are critical to ensuring that the U.S. power system continues to operate reliably and cost-effectively even as demand grows due to electrification. The costs of building incremental transmission remain modest relative to the cost of the electricity system overall. Figure 12 shows that transmission costs accounted for just 13% of average U.S. retail electricity rates in 2018, or 1.4 cents/kWh out of an average retail rate of 10.6 cents/kWh. A 20–50% increase in transmission costs through 2030 associated with the increased electrification load would result in a net increase in transmission spending per kWh of load served of 10–30% and a net rate increase of just 0.15 to 0.39 cents/kWh (1–4% increase over the 2018 average rate) before accounting for offsetting reductions in the generation portion of rates due to the new transmission enabling access to lower cost renewable generation.

Figure 11: Total Regional Transmission Investment due to Electrification
 (a) Base Electrification Case



(b) High Electrification Case

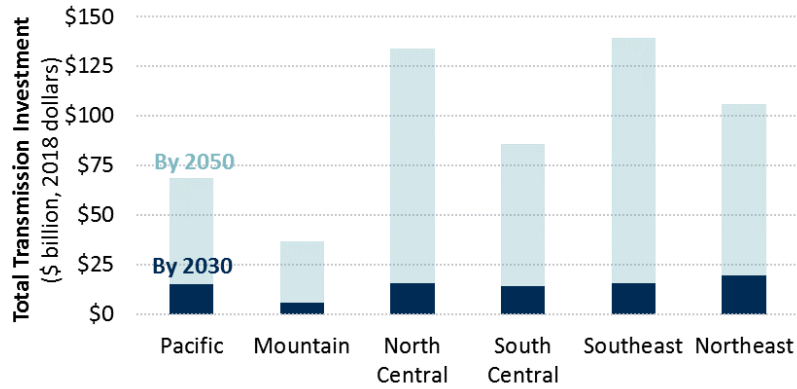
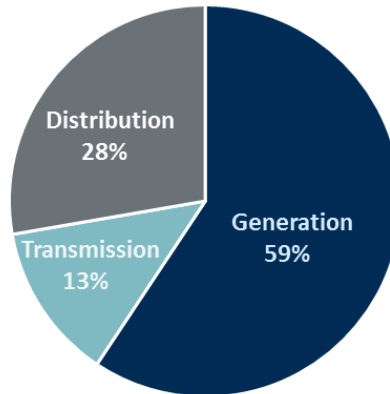


Figure 12: Components of U.S. Average Electricity Prices (2018)



Source: EIA, AEO 2018, Table 55, Electric Power Projections by Electricity Market Module Region, February 2018.

Recent PPA prices for land-based wind range from below \$20/MWh to over \$40/MWh and up to \$70/MWh, reflecting the more than 50% difference in capacity factor across the United States.³⁰ Similarly, accessing higher quality solar resources can reduce the cost of solar PPAs by about \$5 to \$25/MWh.³¹ Building transmission to access higher quality renewable resources to serve the electrification load that are on average \$20/MWh lower cost would reduce the generation portion of the retail rate by about 2–5% in 2030, compared to the 1–4% increase in rates due to the corresponding transmission investments.³² The incremental transmission to access lower cost renewable resources therefore will likely have a very small impact on customer rates and could even lead to a net reduction.

The regional and interregional transmission investments will also be associated with other benefits that will reduce customer costs, such as reducing resource adequacy needs through regional and interregional load diversity.³³

D. Key Takeaways

The electrification of transportation, buildings, and industry/agriculture will have significant impacts across the system and require significant upgrades to the transmission network to supply the rising demand. The results presented in this report suggest the following takeaways for policymakers and transmission engineers to consider when planning the future transmission system:

- In setting clean energy and decarbonization goals, policymakers will increasingly need to gain an appreciation for: (1) the transmission system investments that will be necessary to achieve these goals, and (2) the potential risks of coming up short on achieving those goals and/or doing so at higher costs to consumer by moving too slowly on upgrading the transmission system.

³⁰ Wisner and Bolinger, *Wind Technologies Market Report 2017*, Figure 50. Available at: https://emp.lbl.gov/sites/default/files/2017_wind_technologies_market_report.pdf

³¹ PPAs for high quality solar resources in the Southwest have recently been signed for \$25–30/MWh. The net AC capacity factors in the top quartile of resources are on average about 33%, while in the two lowest quartiles are in the range of 22–28%. Bolinger and Seel, *Utility-Scale Solar: Empirical Trends in Project Technology, Cost, Performance, and PPA Pricing in the United States—2018 Edition*, Figure 14 and 18. Available at: https://emp.lbl.gov/sites/default/files/lbnl_utility_scale_solar_2018_edition_report.pdf

³² The estimated reduction in the generation portion of the retail rates in 2030 accounts for the savings from accessing resources to serve the increase in load due to electrification (20–50% increase) and the portion of that load we assume is served by renewables (75%).

³³ For a summary of the economic benefits of transmission investments, see: Chang, *et al.*, *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, July 2013. Available at: http://files.brattle.com/files/6257_the_benefits_of_electric_transmission_-_identifying_and_analyzing_the_value_of_investments_chang_pfeifenberger_hagerty_jul_2013.pdf

- Over the coming decades, electrification could increase the need for transmission upgrades on average by 15–30% through 2030 and by 50–160% in the decades following 2030, relative to recent historical levels of investment.
- The greatest need for transmission upgrades are likely to occur in the Pacific West and Northeast, which are the regions with the most aggressive decarbonization targets and EV policies and the lowest current per-capita electricity demand
- This level of investment will primarily be necessary to access and integrate low-cost renewable resources to serve the increasing demand for electricity in an increasingly decarbonized future at the lowest total cost. Before accounting for the offsetting savings of accessing lower cost renewables, the transmission investment could increase rates on average by just 2–4% in the near term and 7–24% in the long term.
- Transmission planners will need to start integrating the impact of electrification into their near-term transmission planning to identify the particular needs of their system. This is particularly true in the Pacific West and Northeast, the regions with higher concentrations of first adopters and more immediate policy targets.
- Planners will need to adapt their analysis to account for the uncertainty in the timing, location, and scale of the adoption of electrified loads and the addition of renewable resources. Adding transmission in anticipation of load can be an insurance policy against the high-cost alternative of being unprepared for rising demand and the need to develop short-term, high-cost alternative solutions.

III. Transmission to Support Fast Charging

This second part of this report provides an exploratory analysis of how existing transmission infrastructure could facilitate the cost-effective and rapid ramp up of the deployment of fast charging infrastructure for electric transportation.

A. Overview and Methodology

Access to vehicle charging infrastructure is critically important to a functioning electrified transportation system. Even though most charging of privately-owned electric vehicles currently occurs at home or at the workplace, access to public charging infrastructure, including in particular fast charging infrastructure, is an important element of overcoming “range anxiety.” Having such fast charging infrastructure in place would therefore facilitate the widespread adoption of electric vehicles.

A 2017 report by the U.S. Department of Energy³⁴ estimated a need for 400 DCFC sites along highway “corridors” by 2030, assuming that corridor charging stations are spaced 70 miles apart.³⁵ This estimate may be conservative and given that gas stations tend to be spaced more closely, more DCFC sites may be needed to provide comfort that sufficient fast charging is available along highway corridors.

Assuming therefore that 400–700 DCFC “depots” is a good approximation of the density of corridor DCFC sites likely needed to meet the demand for charging for long-distance travel, an important question relates to the size of the demand for power for each of these DCFC depots. How big a load these corridor DCFC depots will be depends on the number of plugs, the maximum speed of charging, and the assumed coincidence of charging, *i.e.* how many vehicles can charge at maximum speed at the same time.

The maximum speed with which EVs can charge is increasing rapidly. Technology now exists and is beginning to be deployed that allows passenger EVs to charge at speeds of up to 450 kW or even faster. For example, Ionity, a consortium of car manufacturers, is currently in the process of deploying a network of 400 charging stations with charging speeds of up to 350 kW across Europe and up to six charging ports per station.³⁶ In the United States, Electrify America is planning to install 300 highway charging stations, each with at least two 350 kW fast chargers. The average

³⁴ U.S. Department of Energy, “National Plug-In Electric Vehicle Infrastructure Analysis”, September 2017

³⁵ The number of highway corridor fast charging stations needed is sensitive to the assumed minimum distance between stations and charging preferences. For example, it could be twice as high if the desired distance between charging stations is 35 miles rather than 70 miles.

³⁶ For more information on Ionity, see <https://ionity.eu/>

distance between stations will be 77 miles and mostly located at most two miles off highway exits.³⁷ It installed the first 350 kW charging station at a retail store in Chicopee, MA in May 2018.³⁸

One of the important questions that arises in the context of fast charging is whether, given the increasing charging speeds and the potential for simultaneous charging of multiple vehicles, “DCFC complexes” may represent large enough loads to create potential challenges to the network infrastructure if located in weak sections of the grid. Apart from the speed of charging, the size of the load associated with a DCFC complex depends on the number of charging ports. For transit charging, this number is likely related to charging speed since combined, the two determine the capacity of any given DCFC complex to service vehicles. A typical gasoline car refueling process takes approximately 5 minutes and many highway refueling stations have 10 to 20 pumps. Given that charging speeds of 450kW or higher would be needed to provide range comparable to a 5-minute refueling of a gasoline engine, it appears that the current highway gasoline refueling station would be equivalent to 10–20 plugs being capable of charging at 450 kW.

If all of these plugs were simultaneously used at maximum capacity, this in turn would translate into a peak demand of approximately 5–10 MW. Future demand for fast charging may exceed these demands. For example, in the UK, National Grid is planning to install up to 50 charge points with capacity of 350kW each, spaced every 50 miles along major UK highways. Considering both directions of travel, this means that 100 350kW charging points will need to be connected.³⁹ If all were to charge simultaneously, this implies a peak load of 35MW. In addition, assuming that some electrification of heavy-duty transportation will occur, semi-trucks will likely require charging at even higher rates. For example, ChargePoint, a major provider of charging technology, unveiled a 2 MW charger for semi-trucks in 2018.⁴⁰ The collocation of truck-charging stations with passenger DCFC complexes could therefore lead to even higher power demands.

However, there are at least two possible mechanisms to mitigate peak demand from DCFC complexes: First, at least at present, a 450kW charging session is characterized by an initial spike in demand to 450kW, followed by charging at significantly lower power levels. Therefore, even minor “management” of DCFC complex charging, such as delaying the beginning of a session by a

³⁷ Eric C. Evarts, “Electrify America maps out charging network to rival Tesla Superchargers”, Green Car Reports, https://www.greencarreports.com/news/1116375_electrify-america-maps-out-charging-network-to-rival-tesla-superchargers, April 23, 2018.

³⁸ John Briggs, “Electrify America switches on the first 350 KW Fast Charging station in Chicopee, Mass.”, Green Car Reports, https://www.greencarreports.com/news/1116550_electrify-america-switches-on-the-first-350-kw-fast-charging-station-in-chicopee-mass, May 3, 2018.

³⁹ Jimi Beckwith, “National Grid plans 350kW EV charge point network”, Autocar, <https://www.autocar.co.uk/car-news/new-cars/national-grid-plans-350kw-ev-charge-point-network>, February 19, 2018.

⁴⁰ Fred Lambert, “ChargePoint unveils new 2-MW charger for electric aircraft and semi-trucks”, Electrek, <https://electrek.co/2018/05/10/chargepoint-2-mw-charger-electric-aircraft-and-semi-trucks/>, May 10, 2018.

minute or so, could reduce the average demand over multiple simultaneously-occurring charging sessions. Second, even a relatively small amount of on-site battery storage would permit accomplishing the same objective or even further reducing the maximum demand from a DCFC complex.

The analysis therefore assumes that to be futureproof at least some DCFC charging complexes will represent loads in the 5–10 MW range or higher. Such loads, if connected at weak areas of the grid, could require significant network upgrades. While network bottlenecks can occur at both the distribution and transmission level, the addition of loads of this magnitude will tend to represent a smaller challenge at the transmission than at the distribution level.⁴¹ It is therefore possible that existing transmission infrastructure can provide opportunities for the development of DCFC infrastructure that avoids investments in network upgrades and perhaps speeds up the deployment of this critical piece of the EV infrastructure overall. This opportunity has been recognized in the United Kingdom, where National Grid, the UK’s transmission system operator, is in the process of directly connecting super-fast charging infrastructure at 50 sites along highways directly to its transmission system.⁴² The analysis therefore explores similar opportunities along major highway corridors in the United States.

Substantial fast charging infrastructure will also be needed more broadly to complement other charging options. On average, such infrastructure needs to be deployed in relation to overall transportation demand, which is correlated with population density and thus most needed in cities and towns. Fast charging could be public to provide access to EV owners without access to dedicated charging at home or at work or for general convenience charging. Fast charging may be required by various public and private fleets such as electric transit and school buses, various delivery fleets or fleets associated with new mobility offerings such as those provided by ride hailing companies.

The DOE estimated the number of DCFC stations not located along highway corridors. Assuming that any (non-corridor) DCFC station needs to be located at most 3 miles away from typical urban EV users, it estimated that a minimum of 8,100 DCFC stations would be needed in cities and towns to complement home and workplace charging.⁴³

⁴¹ A recent CNN report on a consortium (most likely the above-mentioned Ionity) of car makers building out a 450kW charging network in Europe, refers to the demand of a 20 port charging station as 6 MW or equal to the demand for a small city. Ivana Kottasova, “The electric cars of the future could be recharged in 15 minutes”, CNN Business, <https://www.cnn.com/2018/12/13/business/electric-cars-charge-bmw-porsche/index.html>, December 13, 2018.

⁴² Diarmaid Williams, “National Grid moving ahead on EV super highway”, Power Engineering International, <https://www.powerengineeringint.com/articles/2018/05/national-grid-moving-ahead-on-ev-super-highway.html>, May 8, 2018.

⁴³ 4,900 of these DCFC stations would need to be located in cities, with an additional 3,200 in towns. U.S. Department of Energy, “National Plug-In Electric Vehicle Infrastructure Analysis”, September 2017, p. viii.

The same DOE report also estimated the minimal number of plugs, *i.e.*, the average number of EV chargers located at an EV charging station that would be needed to support a certain number of EVs. It assumes that, on average, 3.4 DCFC plugs would be needed to support 1,000 battery electric vehicles (BEVs)⁴⁴ in cities and towns. Given the number of assumed DCFC stations and an assumed 15 million EVs on the road, half of which BEVs, by 2030, this implies a need for 3.1 plugs per non-corridor DCFC station. Higher penetration of BEVs could indicate either the need for more non-corridor DCFC stations, more plugs per station, or both. The DOE report emphasizes the need to ensure that adequate charging infrastructure be in place to accommodate growth in EV-related demand, both in terms of the speed with which EVs can charge and the number of plugs available.

The potential load of non-corridor fast charging locations is likely highly application specific and hence more difficult to predict. Nonetheless, the loads of urban DCFC stations could well be high enough for network bottlenecks to be an important factor in the cost of interconnection. While distribution networks tend to be denser in urban areas, it is nonetheless possible that existing transmission assets could be leveraged there as well to lower the cost of developing fast charging infrastructure.

To explore potential opportunities for existing transmission infrastructure to cost-effectively (and expediently) support the deployment of DCFC infrastructure, this study uses a relatively high level analysis that compares the location of transportation infrastructure along major roadways and existing transmission assets to identify potential opportunities as well as population density and transmission assets for a small sample of metropolitan areas.

The analyses rely on national spatial data for transmission lines, substations, interstate highways, rest areas, highway exits, and, for relevant cities, urban population density.⁴⁵

⁴⁴ The number of plugs needed is based on BEVs (EVs without a gasoline back-up) since the other major category of EVs, plug-in hybrid EVs, can use regular gas stations for refueling.

⁴⁵ Transmission lines data from Department of Homeland Security, “Electric Power Transmission Lines,” Homeland Infrastructure Foundation-Level Data (HIFLD), August 8, 2018. Available at: <https://hifld-geoplatform.opendata.arcgis.com/datasets/electric-power-transmission-lines>. Substations data gathered from SNL; Rest Areas: Interstate Rest Areas derived from “Map of Rest Areas,” November 16, 2018. Available at: <https://www.interstaterestareas.com/>; Highway Exits derived from ESRI, “North American Highway Exits,” April 10, 2018. Available at: <https://www.arcgis.com/home/item.html?id=77ee392dcabd42a8b0046b9f040d5f28>; Population Density (Boston) from MassGIS, “Datalayers from the 2010 U.S. Census,” April 2012. Available at: <https://docs.digital.mass.gov/dataset/massgis-data-datalayers-2010-us-census>

Population Density (Denver): Denver Open Data Catalog, “Census Block Groups (2010),” January 11, 2018. Available at: <https://www.denvergov.org/opendata/dataset/city-and-county-of-denver-census-block-groups-2010>

Population Density (Ohio): U.S. Census Bureau, “TIGER/Line® with Selected Demographic and Economic Data.” Available at: <https://www.census.gov/geo/maps-data/data/tiger-data.html>

B. Results

This section summarizes the findings of these analyses, first for DCFC corridor charging along highways in the United States and then for a small set of urban case studies, namely Boston, Denver and Columbus, OH.

1. Transmission and Corridor Fast Charging

Figure 13 below shows both the system of major and minor U.S. highways and the existing transmission infrastructure.

Figure 13: Transmission and Highway System



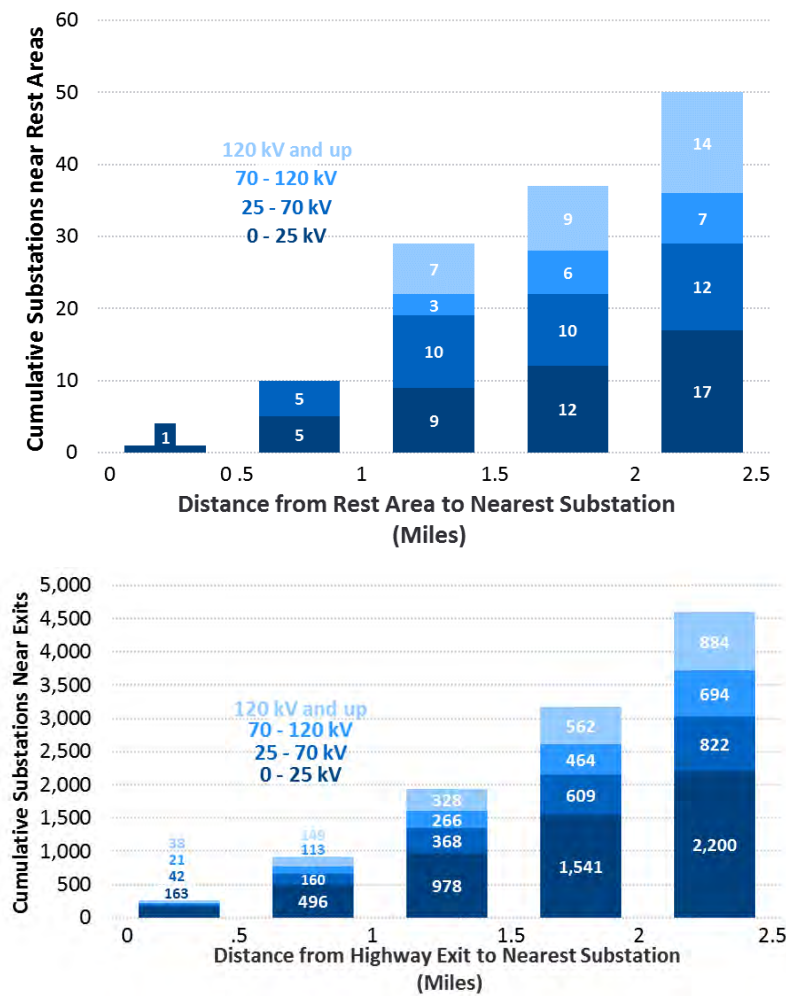
As Figure 13 shows, both highways and transmission infrastructure form a dense web across much of the United States. The analysis examined how proximity between a desirable location for a DCFC charging complex along a highway and a potentially appropriate element of the existing transmission system might create opportunities for leveraging existing transmission infrastructure. Even after conducting interviews with industry insiders both on the transmission and transportation side, it is clear that DCFC infrastructure is still very much in its infancy so that there is little consensus about appropriate or desirable attributes of both highway locations and transmission assets.

On the transportation side, current efforts to deploy DCFC stations along highway corridors focus on highway rest areas and highway exits. On the transmission side, it would seem that existing step-down transformers provide the most obvious opportunity to leverage existing transmission assets. An expert review did not result in an obvious voltage level (at the low side of the

transformer) that would be ideal for an interconnection to a DCFC complex. It does however appear that voltages of 69kV and below would be the most suitable candidates.

The transportation dataset used in this analysis includes information about all highway rest areas and highway exits. The data on existing transmission assets allows differentiating between various transmission elements and among transformers by voltage level. It was therefore possible to estimate the number of rest areas and highway exits that are less than a certain distance from the nearest transmission asset, be it a generator or a transformer (by voltage level).⁴⁶ Figure 14 below summarizes the results of the analysis to identify potentially suitable transmission assets to support the deployment of corridor DCFC complexes.

Figure 14: Proximity of Highway Rest Areas and Highway Exits to Transmission Substations⁴⁷



⁴⁶ The transmission database contains a lot of empty fields so that it is possible that the data is incomplete. The results are therefore likely at the low end of the opportunities that may exist.

⁴⁷ A substation is counted in a given distance range if it is the closest substation for its voltage bracket. For example, a 69kV substation that is .75 miles from a highway exit is counted in the 25–70kV substation bracket and being between 0.5 and 1 miles from a highway exit (there are 160 – 42 = 118 in Figure 14).

As can be seen from the figures, while the number of (current) highway rest areas in very close proximity to appropriate transmission infrastructure is somewhat limited, the picture looks much more promising for highway exits. For example, approximately 650 highway exits are less than one mile from the nearest transmission substation with a low side voltage level of 69kV or lower.⁴⁸

As indicated above, estimates concerning the “needed” number of highway corridor DCFC complexes in the United States range from 400 to 600 or so. The results of the analysis indicate that more than this number of highway exits and rest area are within close proximity of a potentially suitable existing transmission asset. However, this does not mean that all DCFC needs could be met by leveraging existing transmission infrastructure. Rather, a more in-depth analysis of the geographic distribution of suitable highway locations within a short distance of transmission assets would be needed, as well as consideration of other factors determining the least-cost approach to connecting a DCFC complex to the electric system. Nonetheless, the analysis indicates that there may indeed be significant opportunities to lower the cost and/or facilitate the pace of deploying a comprehensive DCFC infrastructure along highways by taking into account the location of existing and potentially appropriate transmission assets.

2. DCFC and Transmission in Urban Environments

As described above, the need for DCFC in urban environments to supplement other charging opportunities, while certain, are less well defined than those along highway corridors. In general, electric service in urban areas is primarily provided by distribution networks, many of which are quite capable of interconnecting larger loads, including DCFC infrastructure of many kinds. Nonetheless, urban DCFC needs could be substantial for certain charging applications—a charging depot for a fleet of mobility service vehicles or urban transit bus fleets, for example—to merit exploring the extent to which existing transmission assets could be helpful to support DCFC build-out in urban areas as well.

The presence or absence of transmission infrastructure in urban areas is highly city-specific and a comprehensive assessment of potential overlaps between transmission assets and potential “needs” for DCFC infrastructure beyond the scope of this report. The same holds true for the locations where DCFC infrastructure may be needed.

Substations in different voltage brackets can refer to the same highway feature resulting in more substations being represented in the figures than actual highway features. In the same example, if there was also an 113kV substation that was 1.25 miles away from the same highway exit, it would be counted in the 70–120kV substation bracket and between 1 and 1.5 miles from a highway exit (there are $266 - 113 = 153$ in Figure 14). It is possible that further distance ranges do not necessarily add more observations since additional substations cannot be counted in previously accounted for voltage buckets. In the example, if there was a second 69kV substation that was 1.75 miles away from the highway exit, it would be ignored, since the closest 69kV substation was accounted for in the 0.5 to 1 mile range.

⁴⁸ 70kV is used as the threshold since some substations have reported voltages slightly above 69kV.

For these reasons, three case studies were analyzed—Boston, Denver and Columbus, OH. In each, population density was used as a proxy for the likely need of DCFC and compared, graphically, to the existing transmission infrastructure. Figure 15, Figure 16 and Figure 17 below show the results of this comparison.

Figure 15: Transmission Infrastructure and Population Density in Boston, MA

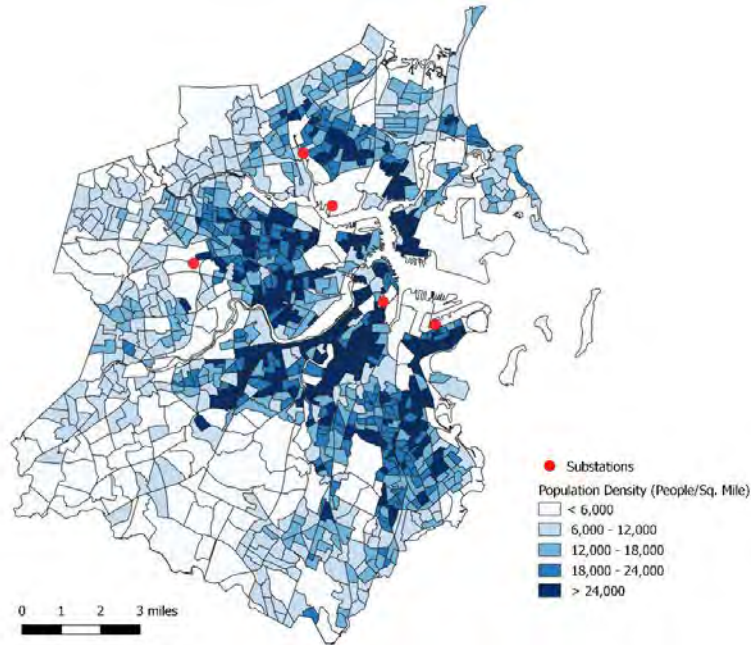


Figure 16: Transmission Infrastructure and Population Density in Denver, CO

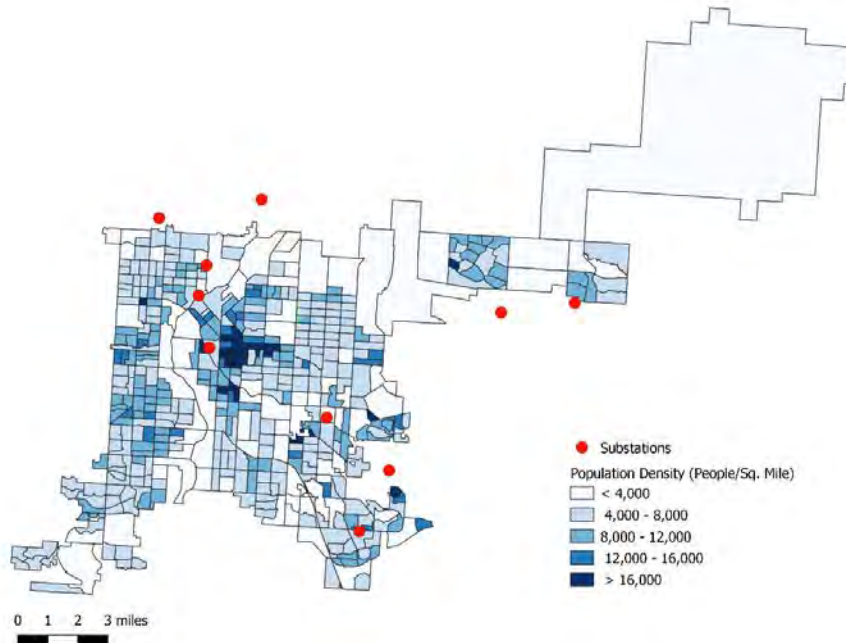
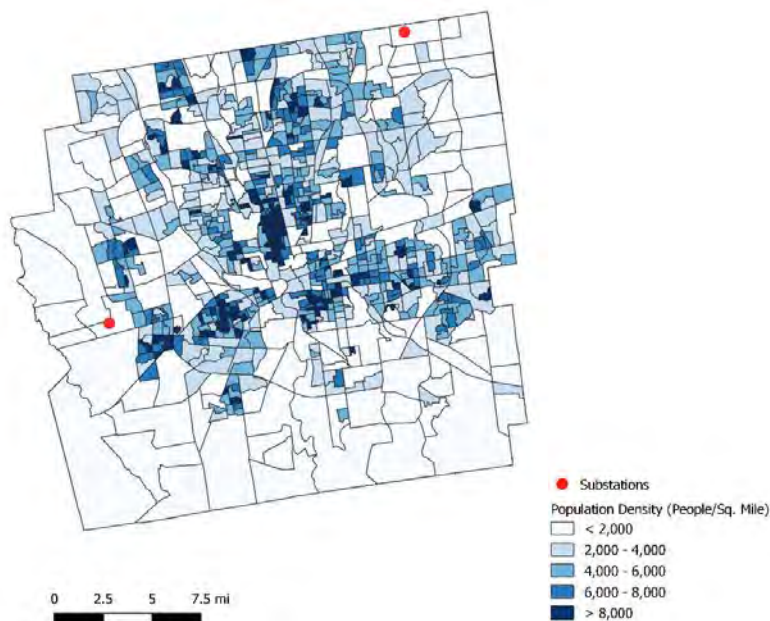


Figure 17: Transmission Infrastructure and Population Density in Columbus, OH



As can be seen from the pictures, the availability of existing transmission infrastructure across the three case studies differs substantially. In Boston, there are several transmission elements located in areas of high population density that could potentially facilitate the development of DCFC. In Denver and Columbus, similar opportunities appear to be more limited.⁴⁹ The absence of suitable existing transmission infrastructure does not imply that transmission may not in some cases be the most cost-effective way to interconnect DCFC infrastructure in urban settings. As indicated, whether or not in individual cases transmission or distribution investments allow for the most cost effective (and rapid) interconnection of urban DCFC stations requires a case-by-case assessment.

3. Discussion

The analysis shows that existing transmission infrastructure has the potential to facilitate the deployment of DCFC infrastructure, in particular along highway corridors: a large number of highway exits is located within 1–2 miles of an existing and potentially suitable transmission substation. With distance or using a wider set of transmission assets, these opportunities are even larger. Whether or not it ever makes sense, either from a cost perspective or in terms of speeding up the process, to connect a DCFC complex directly to a transformer on the transmission network as opposed to connecting it to a transformer on the local distribution network, the frequency with which the two types of assets are located in close proximity suggests that *potential* opportunities

⁴⁹ It should be noted that the publicly-available dataset of transmission assets may not include existing transmission assets below a certain voltage level or be comprehensive otherwise. Additional opportunities beyond those shown therefore likely exist to leverage existing transmission infrastructure in urban settings. As noted elsewhere, whether or not transmission or distribution assets provide the least cost opportunity to interconnect DCFC stations in urban settings requires detailed case-specific analysis.

for cost and/or time savings should be explored by parties interested in developing and connecting DCFC complexes.

The case studies of urban environments suggest that such opportunities may exist there but that these opportunities are likely more dependent on the specific circumstances in the city or town in question. Not only does the type and existence of transmission infrastructure differ greatly between cities, but the type and quantity of DCFC needed to support electrified transportation likely does so as well. For example, the percentage of the urban population without a dedicated parking spot differs tremendously across cities and with it the need to provide public access charging infrastructure. Similarly, fleets providing either cargo or transportation services likely have different needs for locating charging infrastructure in the urban core versus further away from population centers. The absence of suitable existing transmission infrastructure does not imply that transmission may not in some cases be the most cost-effective way to interconnect DCFC infrastructure in urban settings.

As a result, the analysis implies that opportunities for transmission assets to help deploy urban fast charging infrastructure need to be examined on a case-by-case basis, but may well exist in ways that can facilitate a more rapid transition towards electrified urban transportation. For example, given the space constraints and construction challenges that often exist at urban substations, some degree of anticipatory planning aimed at identifying existing substations with extra physical space or capacity could help identify which of the existing transmission assets might be leveraged to develop urban fast charging infrastructure. Similarly, analyzing the potential use of existing assets for fast charging applications could be part of the planning process for expanding existing or constructing new urban substations in areas that may be particularly suitable for future EV fast charging. Both suggest that tighter coordination between transmission, distribution, and transportation planning could have significant benefits.

IV. Technical Appendix

This technical appendix provides more detailed information related to the development of the assumptions used in the analyses underlying the results presented in this report.

A. Incremental Electrification Demand

Projecting the future adoption of emerging technologies, such as electric vehicles and heat pumps, is highly uncertain and driven by several factors. The development of adoption rates was based on a review of the main drivers for each sector, including state and federal policies, the relative economics of the technologies, consumer preferences, as well as recent forecasts of technology adoption.

Due to the uncertainty in the timing and scale of the adoption of these technologies, two scenarios were modeled, each for 2030 and 2050. The “Base Electrification Case” that captures a realistic outlook for the potential scale of electrification in 2030 and 2050 based on current technology and policy drivers. A “High Electrification Case” represents a more heavily policy-driven scenario that significantly reduces GHG emissions nationwide through electrification.

1. Policy Drivers

The analysis is based on a review of the policy drivers for carbon emissions reductions since climate policies that aim to reduce carbon emissions are a significant (although not the only) driver of electrification. Many states also have sector-specific mandates and incentives. Currently these mandates are primarily for EV adoption and include Zero Emissions Vehicle (ZEV) mandates and financial incentives to purchase EVs and EV supply equipment (EVSE).

Table 2 below summarizes by region the current policies that are likely to have the most significant impact on electrification adoption rates. Overall, 52% of the population lives in states with a long-term GHG reduction target. While each mandate, goal, or target is different in terms of its timing, stringency, and firmness, the existence of the policies is interpreted as a sign of the level of support that is likely to exist in the future for adoption of lower-carbon technologies. The Pacific West (99%) and Northeast (77%) have the highest percentage of its population covered by a GHG reduction target, while Southeast (34%) and South Central (0%) have the lowest.

Table 2: Summary of State-Level Policies

	Pacific	Mountain	North Central	South Central	Southeast	Northeast	US
States by Region	5	8	12	4	13	9	51
Carbon Policies							
By State (including DC)							
GHG Reduction Targets	4	3	3	0	5	8	15
Carbon Pricing Policies	2	0	0	0	3	8	5
By % of Population							
GHG Reduction Targets	99%	61%	42%	0%	47%	77%	55%
Carbon Pricing Policies	88%	0%	0%	0%	18%	77%	33%
EV Policies							
EV Market Share (2017)	4.4%	1.0%	0.5%	0.3%	0.5%	1.0%	1.2%
By State (including DC)							
ZEV Program	2	0	0	0	1	7	3
EV Incentives	2	3	3	3	6	6	17

Sources and notes: Carbon policies based on research from Center for Climate and Energy Solutions, EV market shares from www.evadoption.com, EV policies based on research from the National Conference of State Legislatures. VA and NJ are included as states with carbon pricing policies due to their intention of joining RGGI. Washington, DC is included as a state in the Southeast.

2. Transportation Electrification Adoption Rates

In addition to policy drivers, consumers will increasingly have more options for purchasing EVs at a lower premium to conventional vehicles. A few of the key considerations for future EV adoption include:

- Automakers are increasingly rolling out new EV models with over 60 models expected to be available by 2025.⁵⁰
- For example, GM announced that they will offer at least 20 EVs by 2023 and are committed to an “all-electric future.”⁵¹
- Bloomberg New Energy Finance predicts that the upfront costs of EVs will become competitive with conventional vehicles on an unsubsidized basis starting in 2024.⁵²

Figure 18 summarizes publicly-available projections of annual EV market share (both plug-in hybrids and battery electric vehicles). The projections span a wide range with 2030 market share

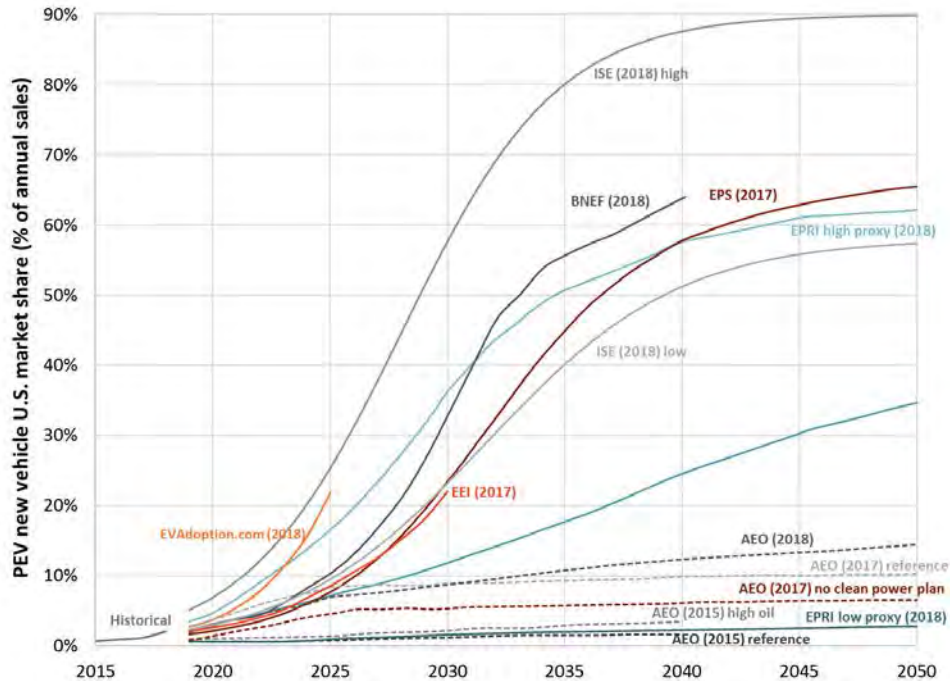
⁵⁰ EVAdoption, Future EVs, <http://evadoption.com/future-evs/>, accessed November 18, 2018.

⁵¹ Jamie L. LaReau, “GM plans expanded Bolt production, 20 new electric vehicles by 2023”, Detroit Free Press, <https://www.freep.com/story/money/cars/general-motors/2018/06/12/gm-plans-expanded-bolt-production-20-new-electric-vehicles-2023/685108002/>, June 12, 2018.

⁵² Bloomberg New Energy Finance, Electric Vehicles Outlook 2018: Global Sales Outlook, <https://about.bnef.com/electric-vehicle-outlook/>, accessed November 18, 2018.

from 2% to 58%. The projections of EVs capturing 20–40% of market share in 2030 were deemed to be the most credible and therefore used in the analysis.

Figure 18: Projections of Annual EV Market Share⁵³



Notes: Historical sales based on monthly EVs sales reported at [InsideEVs.com](https://www.insideevs.com) and annual total vehicles sales reported by the [Federal Reserve Bank of St. Louis](https://www.federalreserve.gov); assumed 2018 total vehicle sales will be equal to 2015–2017 average.

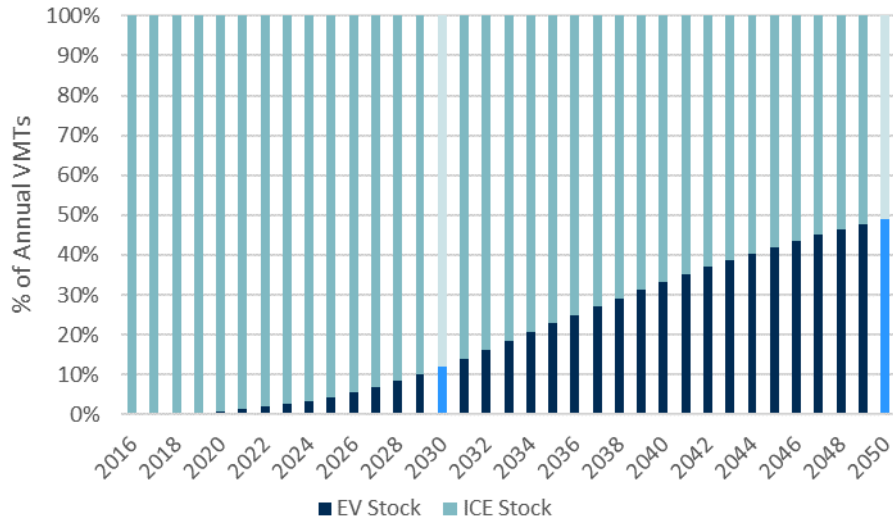
A stock rollover model incorporating the projections in the figure above and reasonable assumptions for vehicle life and vehicle miles travelled (VMTs) per vehicle was used to estimate the number of EVs on the road across the U.S. in 2030 and 2050 and the percent of the total vehicle stock that are EVs, *i.e.*, the adoption rate.

For example, based on the EPRI High case (light blue line in the figure above), 38% of new vehicle sales will be EVs in 2030, which translates into 12% of all vehicles on the road being EVs (or 34 million EVs) in that year. Extending the EPRI High projection out to 2050 results in 48% of

⁵³ We relied on the following sources for the EV projections: For EPRI low proxy (2018) and EPRI high proxy (2018): EPRI, PEV Market Projection Assumptions: June 2018 Update, June 2018. For the AEO projections: U.S. Energy Information Administration Annual Energy Outlook, <https://www.eia.gov/outlooks/aeo/>. For BNEF (2018): Bloomberg New Energy Finance (BNEF), Electric Vehicle Outlook 2017. For EEI (2017): Institute for Electric Innovation, Plug-in Electric Vehicle Forecast: 2016-2025, Interim Report, March 2017. For EPS (2017): Jeffery Rissman, The Future of Electric Vehicles in the U.S., Energy Innovation, September 2017. For EVAdoption.com (2018): "EV sales forecasts," EVAdoption.com, 2018. For ISE (2018) low and ISE (2018) high: Peter Fox-Penner, Will Gorman, and Jennifer Hatch, "Long-term U.S transportation electricity use considering the effect of autonomous-vehicles: Estimates & policy observations." Energy Policy, vol. 122, November 2018, pp. 203-213.

vehicles on the road being EVs (160 million EVs). The annual share of vehicles on the road based on this projection is shown in Figure 19 below. If instead the ISE High projection with the fastest growth in EV market share into the stock rollover model were used, 17% of vehicles on the road in 2030 will be EVs and 72% in 2050.

Figure 19: Projected U.S.-Wide EV Adoption based on EPRI High Forecast



Based on a review of the drivers of transportation electrification, total assumed U.S.-wide EV adoption (% of light-duty vehicles on the road) based on the EPRI High case was: 12% in 2030 and 48% in 2050. For each region, higher or lower EV sales projections were developed based on the policy and market considerations discussed above. Table 3 below summarizes the forecasts for each region.

- *Pacific West and Northeast:* EV adoption rates in 2030 in the regions with the most aggressive electrification policies (Pacific and Northeast) are based on the highest adoption rate forecast above (ISE High), which results in 17% EV penetration in 2030 and 72% in 2050. These adoption rates are 4× higher than those in the region with the slowest adoption rate (South Central).
- *Mountain West:* A slightly lower adoption rate is assumed in the Mountain West region (12% in 2030, 48% in 2050 based on the EPRI High forecast) due to the relatively high percent of the population under the carbon target and lack of ZEV programs.
- *North Central and Southeast:* The North Central and Southeast regions are assumed to have slightly lower adoption rates (7% in 2030, 41% in 2050) due to more limited policies.
- *South Central:* Even without any policies in place, adoption rates in the South Central region is assumed to climb to 4% in 2030 and 22% in 2050, based on the EPRI Med forecast.

Table 3: Base Electrification Case EV Adoption Rates

Region	EV Forecast	Adoption Rates		EVs (million)	
		2030	2050	2030	2050
Pacific	ISE High	17%	72%	7	33
Mountain	EPRI High	12%	48%	3	13
North Central	ISE Low	7%	41%	4	30
South Central	EPRI Med	4%	22%	2	10
Southeast	ISE Low	7%	41%	2	18
Northeast	ISE High	17%	72%	14	69
Total EVs		11%	52%	32	172

In the High Electrification Case the 2030 adoption rates in each region are doubled to achieve 22% penetration nationwide. The study assumes that adoption rates reach 100% in all regions by 2050.

In addition to EV adoption, future total VMTs are assumed to increase beyond the EIA’s projections in the 2018 Annual Energy Outlook. VMTs for LDV (and perhaps other vehicle classes) could increase significantly between now and 2050 as the marginal cost of transportation decreases due to increased use of ride-hailing services, switching from ICE to EVs, and eventually the introduction of autonomous vehicles (AVs). For example, a recent study estimates that ride-hailing leads to approximately 83.5% more VMTs that would have been driven had ride-hailing not existed.⁵⁴ A 2016 NREL study found that the adoption of AVs can result in an increase of VMTs from 10% to 300%⁵⁵ and a 2018 EIA report estimated a potential 35% increase in VMTs by 2050 due to AV adoption.⁵⁶ Another study suggests that AVs will result in a 23%–40% long-term VMT increase.⁵⁷ While there is a large range of projected impacts, 25% higher VMTs by 2050 are assumed in both scenarios. The impact of higher and lower assumptions regarding VMT is tested in the sensitivity analysis.⁵⁸

Medium duty vehicles (MDVs) are also good candidates for electrification based on their cost effectiveness since many of them have more local fleet characteristics, such as delivery trucks and local municipal fleets. Since MDVs are primarily commercial vehicles, the total cost of ownership

⁵⁴ Henaio *et al.*, The impact of ride-hailing on vehicle miles traveled, September 2018. <https://link.springer.com/article/10.1007%2Fs11116-018-9923-2>

⁵⁵ NREL, Estimated Bounds and Important Factors for Fuel Use and Consumer Costs of Connected and Automated Vehicles, November 2016. Available at: <https://www.nrel.gov/docs/fy17osti/67216.pdf>

⁵⁶ EIA, Autonomous Vehicles: Uncertainties and Energy Implications, May 2018. Available at: <https://www.eia.gov/outlooks/aeo/pdf/AV.pdf>

⁵⁷ Fox-Penner *et al.*, Long-term U.S. transportation electricity use considering the effect of autonomous-vehicles: Estimates & policy observations, Energy Policy, Vol. 122, July 2018. Available at: <https://www.sciencedirect.com/science/article/pii/S0301421518304737>

⁵⁸ We will assume VMTs increase linearly between 2018 and 2050 to reach 25% in 2050.

(TCO) will drive adoption more so than for LDVs (where purchasing is influenced by many other factors such as personal tastes). Recent market evidence demonstrate that as models are becoming available operators are choosing to electrify their fleet. For example, Fedex recently announced a plan to add 1,000 electric vans to its fleet.⁵⁹ A 2017 McKinsey report projected that commercial electric vehicles (CEVs) could represent between 8% and 27% of sales by 2030.⁶⁰ A study of decarbonizing transportation in the northeast and mid-Atlantic found that 30% of single unit trucks would electrify by 2050 in its mid case and 70% in its high case.⁶¹

MDV adoption rates are assumed to be near the upper end of this range following the ISE Low forecast in Figure 18 above, reaching 23% of sales in 2030 and 7% of all MDVs on the road. For 2050, 30% adoption is assumed in the base case and 70% in the high case, based on the northeast study. All cases assume the relative penetration of electric MDVs across the six regions to be identical to the assumptions for LDVs.

For long-haul transportation of heavy cargo loads, energy density matters and so adding sufficient heavy batteries for long distances is more costly than for MDVs. Truck manufacturers, such as Freightliner, and new entrants like Tesla are rolling out electric models, which are currently undergoing on-road testing.⁶² There is a potential for alternative low-carbon fuels, such as carbon-neutral biofuels and hydrogen, to replace diesel for the HDV segment. Relying on hydrogen produced through electrolysis for fueling HDVs could increase electricity demand by nearly 3× compared to battery electric trucks. The northeast transportation study assumes just 5% penetration of HDVs by 2050 in its mid case and 30% in its high case.⁶³ There is likely to be some electrification of HDVs; this study assumes it will remain below 5% by 2030 in the Base Electrification Case and 10% by 2050. In the High Electrification Case, it assumes to reach 10% by 2030 and 100% by 2050.

⁵⁹ See: <https://www.reuters.com/article/us-fedex-chanje-vans/fedex-expands-fleet-to-add-1000-chanje-electric-vans-idUSKCN1NP1C3>

⁶⁰ Bernd Heid, *et al.*, What's sparking electric-vehicle adoption in the truck industry?, <https://www.mckinsey.com/industries/automotive-and-assembly/our-insights/whats-sparking-electric-vehicle-adoption-in-the-truck-industry>, September 2017.

⁶¹ Lowell, *et al.*, Decarbonizing Transportation: The Benefits and Costs of a Clean Transportation System in the Northeast and Mid-Atlantic Region, October 10, 2018. ("Lowell, 2018") Available at: <https://www.mjbradley.com/reports/decarbonizing-transportation-benefits-and-costs-clean-transportation-system-northeast-and>

⁶² See: <https://www.trucks.com/2018/06/06/daimler-unveils-electric-freightliner-cascadia/> and <https://www.cnbc.com/2018/03/07/tesla-ceo-musk-touts-semi-test-drive.html>

⁶³ Lowell, 2018.

3. Heating Electrification Adoption Rates

Adoption rate assumptions for residential and commercial heating were developed on the basis of several recent studies that evaluated the cost effectiveness of adopting high-efficiency heat pumps:

- The American Council for an Energy-Efficient Economy (ACEEE) finds that adoption of heat pumps when replacing an existing oil or propane boiler has longer payback periods in colder climates and is more attractive if it also replaces an air condition unit.⁶⁴
- The Rocky Mountain Institute (RMI) finds that air source heat pumps are more cost-effective for space and water heating than fossil fuel boilers in new builds in all four locations they analyzed.⁶⁵ Though for existing houses heated with natural gas, heat pumps are cost effective only when replacing a furnace and air conditioning units simultaneously.
- The National Renewable Energy Laboratory (NREL) Electrification Futures Study found in its “moderate advancement” scenario that air source heat pumps will become cost-competitive with existing gas furnaces in residential applications in the 2030s for most residential cases and by 2050 in cold climates.⁶⁶
- The Regulatory Assistance Project (RAP) finds that electrification of home heating tends to be most cost-competitive in moderate or warm climates with high gas prices and low electricity prices, in new buildings, and in existing buildings that need to replace both the boiler and air conditioning unit.⁶⁷ An LBNL study comes to similar conclusions, highlighting as well that heat pumps are attractive in regions, like the northeast, with higher levels of oil heating.⁶⁸

Table 4 summarizes key metrics for the drivers identified in these studies. The relative price of electricity and gas and the lower heating demand make electrification most attractive in South Central and Southeast. As expected, the demand for heating is greatest in the northern regions and

⁶⁴ ACEEE, Energy Savings, Energy Savings, Consumer Economics, and Greenhouse Gas Emissions Reductions from Replacing Oil and Propane Furnaces, Boilers, and Water Heaters with Air-Source Heat Pumps, July 2018. Available at:

<https://aceee.org/sites/default/files/publications/researchreports/a1803.pdf>

⁶⁵ The study analyzed heat pumps in Oakland, CA, Houston, TX, Providence, RI, and Chicago, IL. Rocky Mountain Institute, The Economics of Electrifying Buildings, 2018. Available at: <https://rmi.org/insight/the-economics-of-electrifying-buildings/>

⁶⁶ NREL, Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050, 2017. Available at: <https://www.nrel.gov/docs/fy18osti/70485.pdf>

⁶⁷ Regulatory Assistance Project, Beneficial Electrification of Space Heating, November 2018. Available at: <https://www.raponline.org/wp-content/uploads/2018/11/rap-shipleigh-lazar-farnsworth-kadoch-beneficial-electrification-space-heating-2018-november.pdf>

⁶⁸ Deason, *et al.*, Electrification of buildings and industry in the United States: Drivers, barriers, prospects, and policy approaches, March 2018, p. 31. Available at: http://eta-publications.lbl.gov/sites/default/files/electrification_of_buildings_and_industry_final_0.pdf

oil heating is found only in the Northeast. The concentration of new building permits in recent years has been the highest in the Mountain West, South Central and Southeast.

Table 4: Drivers of Heating Electrification

	<i>Units</i>	Pacific	Mountain	North Central	South Central	Southeast	Northeast	US
Residential Gas Prices	<i>\$/thousand cf</i>	12	9	9	13	14	12	11
Electricity Rates	<i>cents/kWh</i>	14	9	10	8	10	14	11
Heating Degree Days	<i>Degree days/month</i>	530	820	1,160	470	580	1,070	800
Residential Oil Heating	<i>% of total res dmd</i>	---	---	---	---	---	20%	---
New Building Permits	<i>permits/1,000 pop.</i>	3.5	6.1	2.9	5.3	4.9	2.2	3.9
GHG Emissions Targets	<i>% of US population</i>	99%	61%	42%	0%	47%	77%	55%

Sources and notes: Heating degree days in January and February: EIA Short Term Energy Outlook, October 2018. Residential gas prices: EIA Short Term Energy Outlook, October 2018. Electricity rates: EIA State Electricity Profiles. Residential oil heating: EIA 2015 RECS Survey Data. New building permits: US Census Bureau, New Privately Owned Housing Units Authorized, 2017. GHG Emissions Targets: C2ES Greenhouse Gas Emissions Targets.

Several recent studies have projected the levels of adoption of electrified heating in different regions:

- VEIC projected that in New York by 2030 air source heat pumps may achieve market penetration of 15% of households in its baseline scenario and 65% in its high scenario in which significant policies are in place to support heat pump installations.⁶⁹
- National Grid projected in its Northeast 80×50 Pathway study that 28% of residential demand for heating will be electrified by 2030, up from 2% today.⁷⁰
- Projections for meeting carbon policies in Minnesota found that 10–15% of space heating will need to be electrified by 2030 and 63–72% by 2050, with water heating slightly higher at 69–75%.⁷¹
- A survey by LBNL of electrification pathway studies in California found that they assume heating will need to be 55% to 100% electrified by 2050.⁷²

⁶⁹ VEIC, Ramping Up Heat Pump Adoption in New York State: Targets and Programs to Accelerate Savings, Prepared for NRDC, September 25, 2018. Available at: <https://www.veic.org/documents/default-source/resources/reports/veic-ramping-up-heat-pump-adoption-in-new-york-state.pdf>

⁷⁰ National Grid 80×50 study.

⁷¹ Vibrant Clean Energy, Minnesota’s Smarter Grid: Pathways Toward a Clean, Reliable, and Affordable Transportation and Energy System, July 31, 2018, p. 11.

⁷² Deason, *et al.*, Electrification of buildings and industry in the United States: Drivers, barriers, prospects, and policy approaches, March 2018. Available at: <https://emp.lbl.gov/publications/electrification-buildings-and>

Based on these factors, Table 5 shows the assumptions for heating electrification across the six regions. In the short term, the main drivers are the relative economics of heat pumps and the regions with the warmest climates such that the highest penetration rates in 2030 are assumed to occur in the Pacific West, South Central and Southeast. The Northeast penetration is lower due to the colder climate, but higher than North Central due to the amount of oil-fired heating. Mountain West is in the middle of the range due to its varied climates and the amount of new builds. A 10% higher penetration rates across all regions was assumed in the 2030 High Electrification Case.

Table 5: Heating Electrification Adoption Rates

	Pacific West	Mountain West	North Central	South Central	Southeast	Northeast
Base Electrification Case						
2030	7.5%	5.0%	2.5%	7.5%	7.5%	5.0%
2050	40%	30%	25%	25%	30%	35%
High Electrification Case						
2030	15%	10%	5%	15%	15%	10%
2050	100%	100%	100%	100%	100%	100%

For 2050, policy mandates become a more significant driver such that the Pacific West is the highest penetration at 75% and Northeast is slightly lower at 65% due to the colder climate. Penetration in the Mountain West and Southeast are slightly lower at 60% due to less of its population under carbon reduction goals (but more than other regions) balanced by the better economics of heat pumps in the warmer climates.

As highlighted by RAP, a key assumption for the adoption of heat pumps is the efficiency of the building in which the units are installed. The more efficient the building, the easier it is for air source heat pumps to provide the heating load necessary in colder climates. For that reason, energy efficiency can be an enabler of heating electrification while muting the potential load growth due to the adoption of heat pumps. Currently the EIA assumes limited future energy efficiency investments occur in the residential sector as their projections are based solely on the existing policies in place, and do not account for continuation of near-term policies or expanded policies in the future to support EE investments. In the commercial sector, the EIA assumes that new buildings will increase their efficiency by 0.3% per year on average and existing buildings will do so by 0.5% per year. The study uses the assumption that residential and commercial efficiency will increase by an additional 1% per year to account for expanded EE investments. Many states target about 2% per year of energy efficiency savings.

4. Industrial and Agricultural Electrification

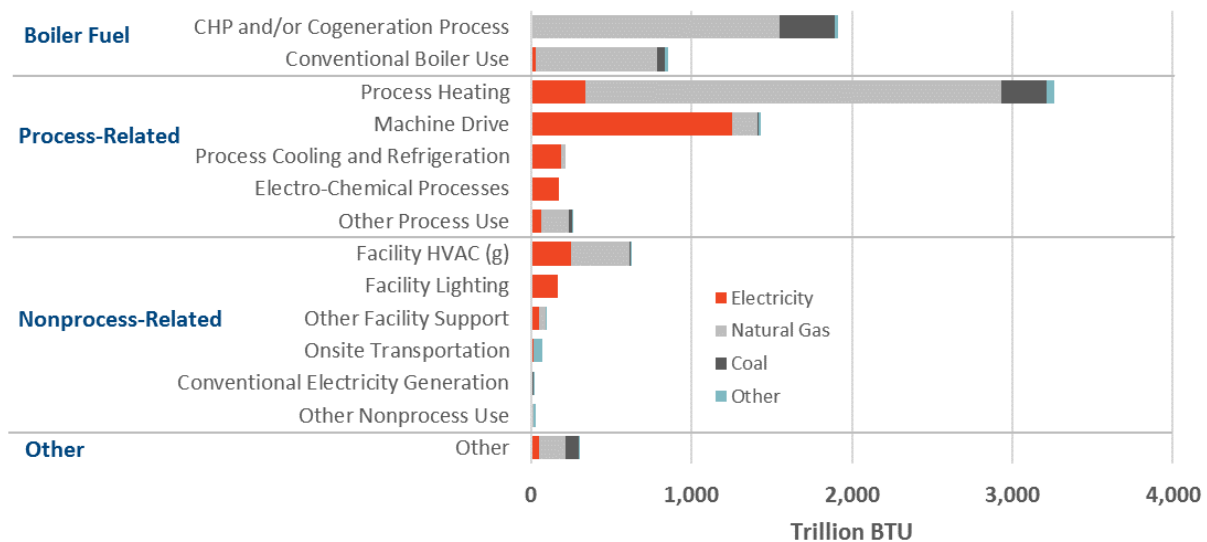
The industrial and agricultural sectors represent approximately 30% of total U.S. energy demand. Within these sectors, manufacturing processes account for 80% of the total energy demand, while construction, agriculture, and mining account for the remaining 20%. The South represents almost 60% of the energy demand for manufacturing, followed by the Midwest, which represents 25%.

The industries that predominate in these regions are the manufacturing of chemicals, petroleum and coal products, paper, primary metals, and food, as well as agriculture.⁷³

Currently about 70% of industrial and agricultural energy demand comes from coal and natural gas and the remaining 30% is from electricity. The largest electricity consuming sectors are primary metal, chemical, and food manufacturing.

Figure 20 shows that electricity is currently used for a variety of end-uses, including machine drive, process heating, cooling, and refrigeration, and lighting. However, there is still electrification potential for some of these end-uses, such as facility HVAC.

Figure 20: End-Uses of Fuel Consumption for Manufacturing



Source and notes: EIA 2014 Manufacturing Energy Consumption Survey (MECS) Data. 'Other' includes net steam and other energy that survey respondents indicated was used to produce heat and power. Other fuel includes fuel oil, diesel fuel, and residual fuel oil.

Given the variety of industrial processes and complexity of industrial technologies, a top-down approach was used to project the electrification of agricultural and industrial energy use. First, the increase in industrial load due to electrification was estimated based on recent nationwide studies of electrification potential. Second, the total estimated load increase was split by region using regional industrial energy consumption data. Finally, electrification adoption rates were estimated by comparing electrified industrial demand to the sector's fuel demand.

The increase in industrial load due to electrification was determined based on a review of studies that modeled the nationwide electrification of the industrial sector, including agriculture. NREL's Electrification Futures Study estimates no increase in industrial load by 2050 for the reference and medium adoption scenarios, and an 8% increase in industrial load by 2050 in the high adoption

⁷³ EIA 2014 Manufacturing Energy Consumption Survey (MECS) Data.

scenario.⁷⁴ EPRI's U.S. National Electrification Assessment forecasts a 10% increase in industrial load by 2050 in the reference scenario and a 65% increase in the transformation scenario.⁷⁵ Given the range of adoption forecasts from these studies, the analysis assumes a 2% increase in industrial load by 2030 and a 10% increase by 2050 for the base adoption scenario and a 20% increase in industrial load by 2030 and 65% increase in 2050 for the high adoption scenario.

Next, historical nationwide industrial and agricultural energy demand from the EIA Annual Energy Outlook was used to split the additional industrial load geographically.⁷⁶ As agricultural energy demand was unavailable at a regional level, agricultural GHG emissions by region from the CAIT Climate Data Explorer were used to split total energy demand by region.⁷⁷ The EIA data on regional industrial energy demand was used to split the remaining non-agriculture industrial energy demand by region.

B. Incremental Generation Resources

This section provides more detail on the development of assumptions of the incremental supply resources that would be added to the system to serve the additional load caused by electrification. These assumptions were developed based on an analysis of the availability and cost of renewable resources in each region, the states with carbon emissions reduction targets, and the renewable capacity additions assumed by the EIA in its long-term Annual Energy Outlook (AEO) projections. Table 6 below provides a summary of the main drivers and a short description of the rationale behind the levels of capacity in each region used in the transmission needs analysis. The supply-related assumption that has the most significant impact on transmission needs is the percent of incremental supply from gas-fired generation versus clean resources. Shifting 20% of generation between renewable resources has a relatively small impact, but shifting the same amount of generation from renewables to gas is much more impactful. This is because new gas-fired generation can be built near load centers and often on the site of older fossil generation and thus requires less transmission.

⁷⁴ Mai, *et al.*, *Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States*, 2018.

⁷⁵ Approximation from report figures. EPRI, *U.S. National Electrification Assessment*, April 2018.

⁷⁶ EIA, *2018 Annual Energy Outlook*, https://www.eia.gov/outlooks/aeo/tables_ref.php, February 6, 2018.

⁷⁷ World Resources Institute, *CAIT Climate Data Explorer*, <https://www.wri.org/our-work/project/cait-climate-data-explorer>, accessed December 2018.

Table 6: Regional Generation Mix Assumptions

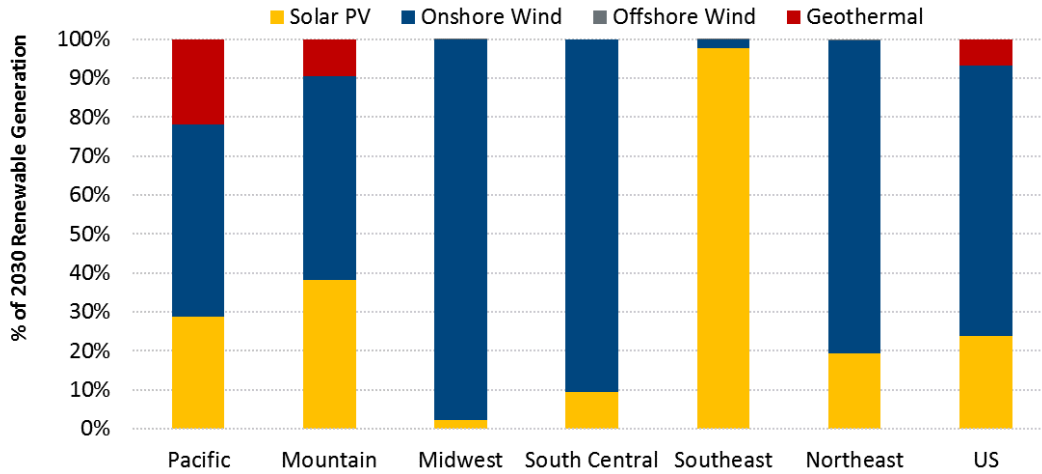
Region	Primary Drivers	2030	2050
Pacific West	Region dominated by California’s load, carbon policies and procurements. PacifiCorp also has no plans for new fossil in its latest IRPs. Best resources are solar, but also good wind in north and potential for wind imports.	<ul style="list-style-type: none"> - 90% RE/10% gas - Primarily solar (40%) - 25% geothermal, similar to current mix - Some incremental hydro from NW (10%) - Imported or upgraded wind (15%) 	<ul style="list-style-type: none"> - 100% RE additions - Similar mix, but with some offshore wind added in OR (10%)
Mountain West	Large geographic region with excellent RE resources (solar in south, wind in WY/CO/NM), but also access to cheap gas. The Mountain West states have a mix of climate goals.	<ul style="list-style-type: none"> - 70% RE/30% gas - Equal mix of solar and wind (both 30%) - Geothermal at 10% with resources in NV - No hydro or offshore wind 	<ul style="list-style-type: none"> - 90% RE/10% gas - Maintain equal amounts of wind and solar (now 40% each) to replace gas
North Central	Wind-dominated region with carbon reduction goals in MN, IL, MI.	<ul style="list-style-type: none"> - 80% RE/20% gas - 50% wind due to high quality resource - 20% solar - 10% hydro imports from Canada 	<ul style="list-style-type: none"> - 90% RE/10% gas - Increase solar to 30% to diversify RE mix away from wind
South Central	High quality resources, including RE and gas; no carbon reduction goals	<ul style="list-style-type: none"> - 80% RE/20% gas - 50% wind with about half located along the gulf coast - 30% solar from West Texas 	<ul style="list-style-type: none"> - 90% RE/10% gas - Increase solar to 40% to diversify RE mix away from wind
Southeast	Best solar on east coast, but otherwise limited for RE resources. FL, NC and MD have set carbon reduction goals.	<ul style="list-style-type: none"> - 60% RE/40% gas - Most dependent on solar (40%) - Some offshore wind (10%) in MD/VA - Also some imports of wind from North Central (10%) 	<ul style="list-style-type: none"> - 80% RE/20% gas - Diversify away from solar with more offshore wind (20%) and onshore wind (20%)
Northeast	All states other than PA are in RGGI with carbon reduction goals throughout the region; limited onshore wind and solar resources, but access to high quality offshore wind and Canadian hydro.	<ul style="list-style-type: none"> - 90% RE/10% gas - Primarily rely on high quality OSW resources (30%) - 25% solar based on recent NY CES procurement - Increased hydro imports from HQ/ON (20%) - Some onshore wind (15%) 	<ul style="list-style-type: none"> - 100% RE - Increased OSW (35%) and solar (30%) to meet higher RE needs

The assumptions about the incremental generation mix likely to meet incremental generation needs due to electrification were developed based on a review of several sources and The Brattle Group’s experience. The sources include:

- The EIA’s projection of the mix of renewable generation in 2030 in the 2018 Annual Energy Outlook in Figure 21 and their projection of the incremental renewable additions between 2030 and 2050 in Figure 22;

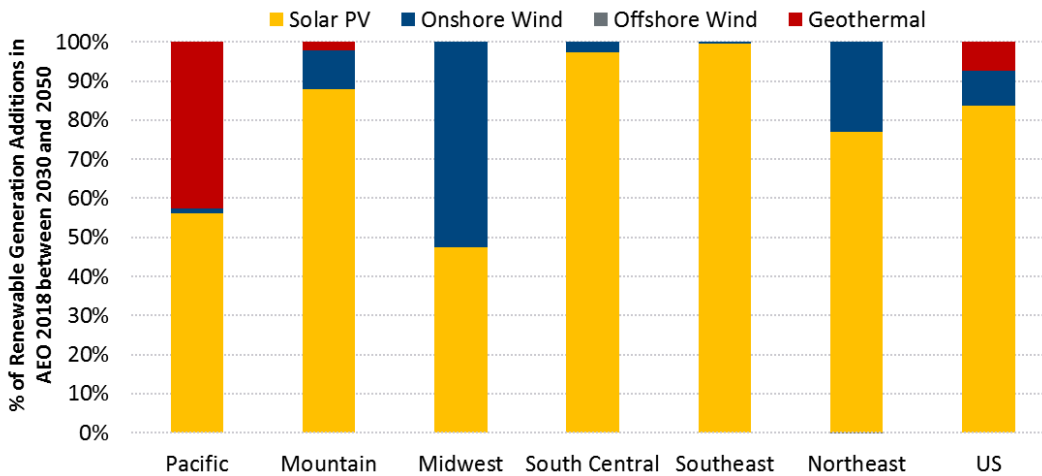
- A map of the lowest cost new generation technologies by county across the U.S. in Figure 23 projected by researchers at the University of Texas; and,
- A summary of states with greenhouse gas emissions targets in Figure 24.

Figure 21: EIA Projection of Renewable Generation in 2030



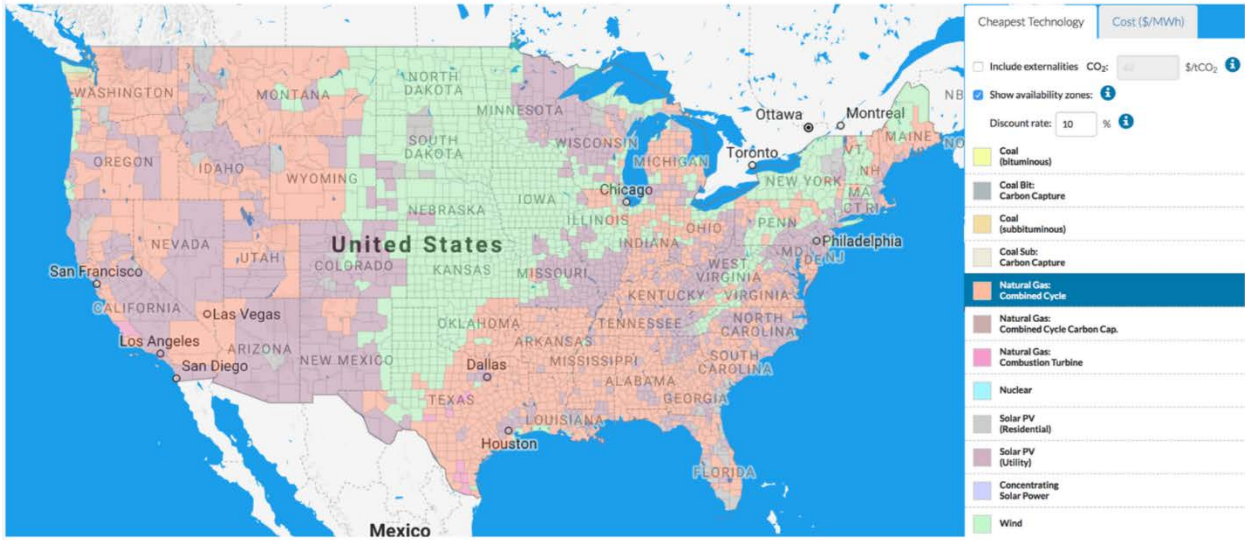
Source: EIA AEO 2018.

Figure 22: EIA Projection of Incremental Renewable Generation from 2030 to 2050



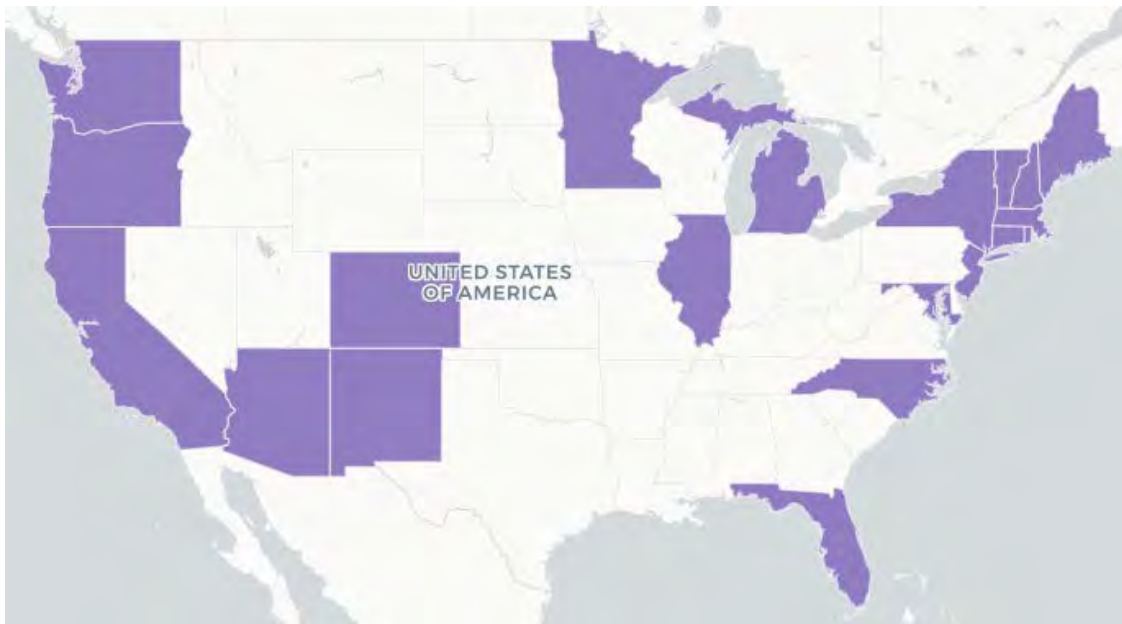
Source: EIA AEO 2018.

Figure 23: Lowest Cost Resources for Supplying Incremental Demand



Source: University of Texas, New U.S. Power Costs: by County, with Environmental Externalities, accessed November 18, 2018.

Figure 24: States with Greenhouse Gas Emissions Targets



Source: Center for Climate Policies and Energy Solutions, State Climate Policy Map, <https://www.c2es.org/content/state-climate-policy/>, accessed November 19, 2018.

C. Estimating Future Transmission Needs

This section provides additional detail about the development of assumptions and analysis concerning the amount of transmission investment that is projected to be necessary in a future with rising peak load and renewable capacity due to electrification. It begins with a presentation of an analysis of historical transmission investment versus load growth at a national scale to develop an estimate of transmission needs per kW of incremental peak load growth. It then

presents a review of recent studies that evaluate high renewable futures and the need for transmission in those futures to develop an estimate of transmission needs per kW of incremental renewable capacity.

1. Transmission Needs for Peak Load Growth

Transmission investments are necessary as the peak load increases to maintain a reliable and efficient grid. The estimate of how much transmission will be needed to meet peak load growth due to electrification was based on a comparison of historical peak load growth projections over the past 20 years to transmission investments during that time. This analysis is summarized in Table 7.

Table 7: Historical U.S.-Wide Transmission Investments and Peak Load Growth Forecasts (1996-2016)

	NERC-Projected Peak Load Growth Over Forecast Period		Actual Tx Investment Over Forecast Period			Tx Investment / Peak Load Growth Forecast \$/kW
	Total GW	Annual GW	Total \$ million (2016)	Load Growth Related (33%)		
				Total \$ million (2016)	Annual \$ million (2016)	
	[1]	[2]	[3]	[4]	[5]	[6]
5-Yr Forecasts						
1996 - 2001	57	11	\$16,771	\$5,590	\$1,118	\$99
2001 - 2006	74	15	\$25,366	\$8,455	\$1,691	\$115
2006 - 2011	79	16	\$45,169	\$15,056	\$3,011	\$191
2011 - 2016	58	12	\$81,240	\$27,080	\$5,416	\$465
9-Yr Forecasts						
1998 - 2007	112	12	\$43,832	\$14,611	\$1,623	\$131
2007 - 2016	136	15	\$119,305	\$39,768	\$4,419	\$293

Sources: Transmission investment based on Brattle analysis of FERC Form 1 data. Peak Load Growth forecasts based on annual NERC forecasts.

Columns 1 and 2 list historical levels of nation-wide transmission investments during 5-year and 10-year forward-looking periods from 1996 to 2016. We then assumed that a certain percentage of the total national transmission investment was due to peak load growth. The results shown in Table 7 assume that 33% of total transmission investments since 1996 were related to peak load growth (with a range of 20%–50% explored as a sensitivity in Table 8). The remaining two-thirds of total transmission investments (with a 50%–80% range explored as well) are primarily related to (a) generation interconnections and public policy needs and (b) the replacement of aging infrastructure. Under this 33% assumption, peak load growth-related transmission investments have been between \$1 billion to \$5 billion per year over the past 20 years or approximately \$100–\$400 per kW of peak load growth.

NERC publishes a 10-yr peak load forecast on an annual basis, which was used to estimate the projected increase in peak load at the beginning of each of the 5- and 9-yr timeframes shown in the table below. On average, NERC has forecasted U.S.-wide peak load growth of 10–16 GW per year over the past 20 years.

The estimated peak-load-growth-driven investment per kW of forecasted peak load growth during each time period was calculated as shown in Table 7. Under these assumptions there has historically been \$99–\$465 of transmission investment per kW of peak load growth.

Peak load-driven transmission investments under a lower (20%) and higher (50%) assumption for the percent of investment driven by load growth were also estimated, as shown in Table 8.

Table 8: Alternative Assumptions for Transmission Investments Driven by Peak Load Growth (\$/kW)

	% of Total Tx Investments Related To Load Growth		
	20%	33%	50%
5-Yr Forecasts			
1996 - 2001	\$59	\$99	\$148
2001 - 2006	\$69	\$115	\$173
2006 - 2011	\$115	\$191	\$287
2011 - 2016	\$279	\$465	\$698
9-Yr Forecasts			
1998 - 2007	\$79	\$131	\$196
2007 - 2016	\$176	\$293	\$440

This analysis was used to develop a reasonable base assumption for transmission investment of \$200/kW of peak load growth, with a low case of \$100/kW and a high case of \$400/kW.

2. Transmission Needs for Renewables

Several studies of transmission investment needed to accommodate the expansion of renewable generation cover several different geographies, mix of renewable resources, and total renewable generation capacity. The transmission costs in these studies range from \$100–\$900/kW of renewable generation capacity and are summarized in Table 9. These values are similar to the costs that The Brattle Group has previously estimated for renewables-related transmission of \$300–600/kW based on the costs required for actual investments in transmission overlays planned primarily to integrate renewable generation, such as Tehachapi, the Texas CREZ lines, and the MISO MVP projects, plus an additional \$100/kW for local upgrades, which is included in the bottom row of the table.

Table 9: Summary of Transmission-Related Studies

Study (Date)	Region	Investment Cost (\$/kW, 2018\$)	Renewable Resources	Renewable Capacity
NREL Interconnections Seam Study (2018)	US-wide	\$114–141/kW	Wind and Solar	439–571 GW
LBNL Cost of Transmission for Wind Energy (2009)	US-wide	\$0–1,500/kW Median = ~\$300/kW (nominal \$)	Wind	63 MW to 236 GW
NREL Western Wind & Solar Integration Study (2010)	AZ, CO, NV, NM, WY	\$451/kW	Wind and Solar	30–33 GW
MISO Regional Generation Outlet Study (2010)	MISO states	\$682–902/kW	Wind	28 GW
Brattle Transmission Investments to Integrate Renewables (2010)	Project-Specific	\$300–600/kW, plus \$100/kW for local upgrades	Wind	—

Sources: Aaron Bloom, Interconnections Seam Study, Presented to TransGrid-X Symposium, 2018. Mills, *et al.*, The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies, February 2009. GE Energy, Western Wind and Solar Integration Study, prepared for the NREL, May 2010. Midwest ISO, Regional Generation Outlet Study (RGOS), November 19, 2010.

A second approach used the historical transmission investment from the peak load growth analysis above to estimate the amount of transmission investment required for accessing and integrating renewable generation. From 2007 to 2016, 93 GW of wind and solar were built in the U.S. During that time there was about \$120 billion in transmission investments as shown in Table 7 above. Assuming that one-third of the transmission investment during this time was due to the need to integrate renewables, the average transmission investment is \$425/kW of renewable capacity, which is similar to the midpoint of the values in the table above.

Based on these estimates, a range of \$300–\$700/kW of renewable capacity is used in the analysis of incremental transmission investment costs, with a central estimate of \$500/kW. While the NREL Seams study is the most recent and largest scale analysis, the range used in this study relies more heavily on the actual historical transmission projects analyzed in earlier studies.