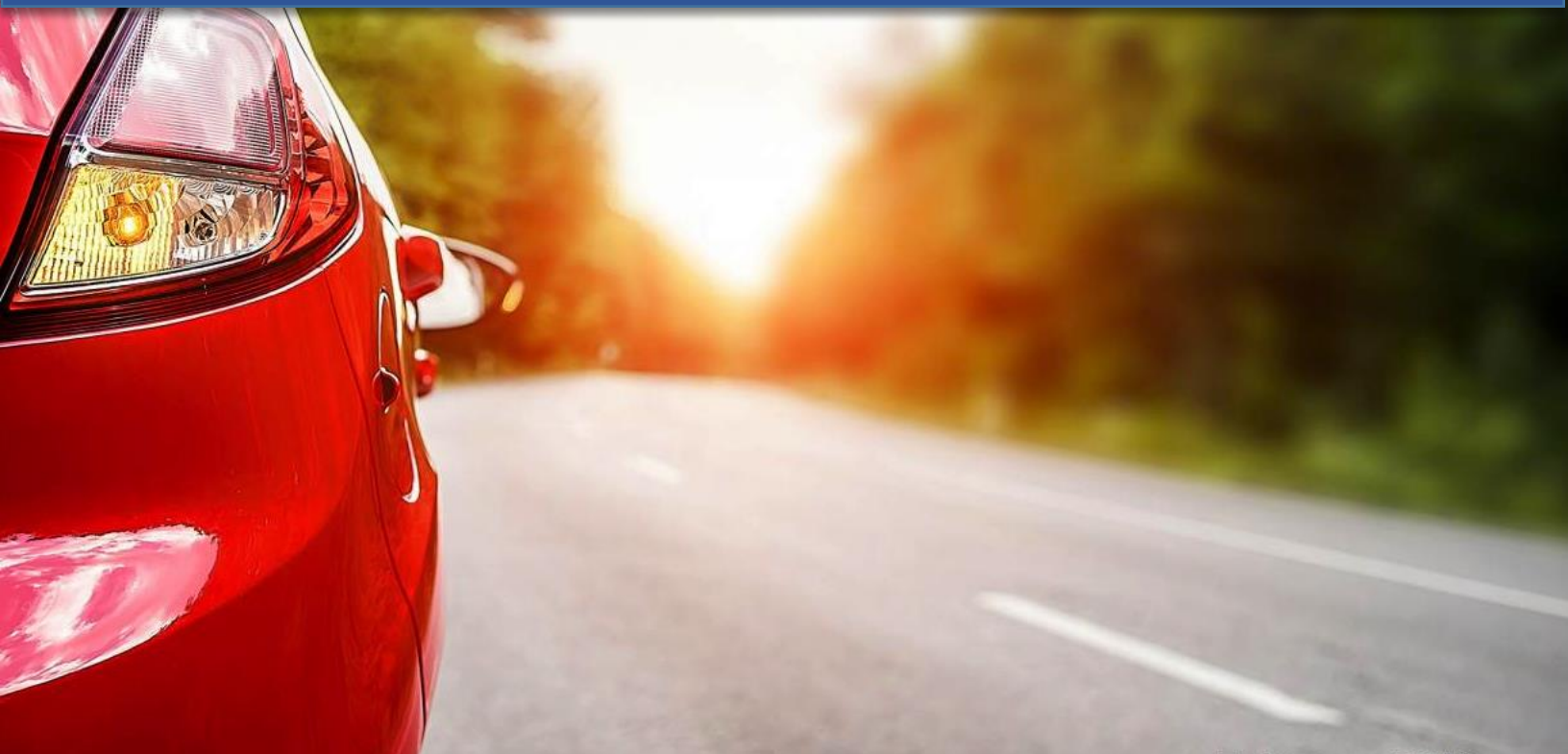




Grid Integration Tech Team and
Integrated Systems Analysis Tech Team

Summary Report on EVs at Scale and the U.S. Electric Power System

November 2019



The U.S. DRIVE Grid Integration Technical Team (GITT) and Integrated Systems Analysis Technical Team (ISATT) members contributed to this report in a variety of ways, ranging from work in multiple study areas to involvement on a specific topic, as well as drafting and reviewing proposed materials. Involvement in these activities should not be construed as endorsement or agreement with the assumptions, analysis, statements, and findings in the report. Any views and opinions expressed in the report do not necessarily reflect those of American Electric Power, Argonne National Laboratory, BP America, Chevron Corporation, DTE Energy, Duke Energy, the Electric Power Research Institute, ExxonMobil Corporation, FCA US LLC, Ford Motor Company, General Motors, the National Renewable Energy Laboratory, Oak Ridge National Laboratory, Idaho National Laboratory, Pacific Northwest National Laboratory, Phillips 66 Company, Shell Oil Products U.S., Southern California Edison Company, U.S. Council for Automotive Research LLC, or the U.S. Department of Energy.

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Definitions¹

Balancing Authority – The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority area, and supports Interconnection frequency in real time (i.e., synchronized frequency across balancing authorities that are electrically tied together during normal system operation at regional scale or greater).

Bulk Power System – (A) Facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) Electric energy from generation facilities needed to maintain transmission system reliability.

Demand – (1) The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. (2) The rate at which energy is being used by the customer.

Dispatch– The allocation of demand to individual generating units on line to effect the production of electricity.

Distributed Energy Resource – Any generating resource (e.g. photovoltaics, battery energy storage, cogeneration, etc.) that connects to the distribution system and is not otherwise included as part of the bulk power system.

Distribution – The collection of lines, commonly referred to as wires, and associated equipment between the transmission system and the end-use customer.

Distribution Capacity – The maximum load carrying capability, commonly expressed in megawatts (MW) of all wires and equipment used to serve load on the grid.

Energy Generation – The total amount of electrical energy, commonly expressed in megawatt-hours (MWh), produced at the generating stations.

Generation Capacity – The maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, adjusted for ambient conditions.

High-power Charging – Charging of electric vehicles at rates of 150 kW and above. Typically DC-connected and referred to as fast, extreme-fast, ultra-fast, or supercharging.

Intermittent Resource – An electric generating plant with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements.

Load – An end-use device or customer that receives power from the electric system

Low-power Charging – Charging of electric vehicles at rates of 1.6 to 10 kW. Typically AC-connected and commonly referred to as Level 1 (L1) and Level 2 (L2) charging.

Managed Charging – Mechanisms including price signals, direct control, incentives, etc., external to the electric vehicle (EV) and electric vehicle supply equipment (EVSE, also

¹ These definitions where applicable have been adopted from North American Electric Reliability Corporation (NERC) [26] and the U.S. Energy Information Administration (EIA) [27] glossaries.

commonly called chargers or charging stations) that enable and facilitate a better coordination of charging with the electric grid.

Ramp – The rate, expressed in megawatts per minute, that a generator changes its output.

Transmission – An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Executive Summary

Electric vehicles (EVs) can meet U.S. personal transportation needs using domestic energy resources while at the same time offering carbon emissions benefits [1]. However, wide scale light-duty EV adoption will necessitate assessment of and possibly modification to the U.S. electric power generation and distribution systems. The objective of the report is to gauge the sufficiency of both energy generation and generation capacity in the U.S. electric power system to accommodate the growing fleet of light duty EVs. As used in this report, the term EV refers to both light-duty battery electric vehicles (BEVs) and light-duty Plug-In Hybrid Electric Vehicles (PHEVs) but excludes fuel cell electric vehicles and hybrid electric vehicles that do not plug in to charge the battery.

In the report, the Grid Integration Tech Team (GITT) and Integrated Systems Analysis Tech Team (ISATT) of the U.S. DRIVE Partnership examine a range of EV market penetration scenarios (low, medium, and high) and associated changes to the U.S. electric power system in terms of energy generation and generation capacity. In this report, Energy Generation is the total amount of electrical energy, commonly expressed in megawatt-hours (MWh), produced at the generating stations and Generation Capacity is the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, adjusted for ambient conditions. Those future potential changes in energy generation and generation capacity, in turn, are compared to historical trends, including explicit quantifications for the year 2030, as it roughly corresponds to the period of highest annual EV market growth in the high EV market penetration scenario considered here. The ability of U.S. energy generation and generation capacity to handle this type of rapid growth is the core question being examined in this paper, and these historical comparisons illustrate that there have been sustained periods of time in the past where growth in load exceeded the ranges of additional electricity consumption and peak demand associated with the future EV market scenarios considered here.

The latter half of the 20th century included periods of annual energy generation growth equivalent to the electrical consumption of as many as 25 million new light duty EVs (the equivalent of roughly 150% of all new light-duty vehicle sales in the U.S. today). This represents 4 to 10 times the projected EV market growth through 2030 in the high and medium scenarios respectively. Periods of highest energy generation growth (in the 1970s and 1990s) included expansions to baseload generation from nuclear and fossil sources at a time when the policy environment allowed for necessary investment. In contrast, over the last ten years, declines in new demand have moderated energy generation growth to near zero; growth in the EV market could change that trend.

Despite this flat energy generation growth within the last decade, the U.S. electric power system added an average dispatchable generating capacity of 12 GW per year, with years that exceeded 25 GW when including intermittent resources. In an unmanaged charging scenario intentionally chosen as an illustrative worst case, 12 GW of dispatchable generating capacity is equivalent to the aggregate demand of nearly 6 million new EVs. This accounts to 1 to 3 times the projected EV market growth through 2030 in the high and medium scenarios respectively. This case does not account for managed charging (i.e., using smart communications technology to coordinate EV charging over the course of a day), which offers additional flexibility to reduce peak demand and which will play an important role in integration of EVs at Scale. This

integration of EVs with intermittent resources warrants additional investigation to understand the co-occurrence of resource availability with EV charging flexibility to determine the incremental EVs that could be supported. Similarly, the potential for EVs to help manage intermittent supply of renewables through managed charging warrants additional study.

The overall conclusion the analysis in this paper demonstrates is that, based on historical growth rates, sufficient energy generation and generation capacity is expected to be available to support a growing EV fleet as it evolves over time, even with high EV market growth. The analysis also points out that growth in incremental energy generation associated with the future EV market scenarios considered here may reverse the trend over the last 10 years of near-zero growth. It is also important to note that non-technical factors such as policy, regulatory framework, and economic constraints may have changed over the period corresponding to the historical data presented here and may affect future energy generation and generation capacity expansion. Though such factors are outside the scope of this summary report, other more detailed U.S. DOE efforts already underway intend to study potential impacts and possible bottlenecks.

While this summary report focuses on the impacts of light-duty vehicles on energy generation and generation capacity, it acknowledges several potential challenges at the distribution level. Consideration of the following warrant additional analysis:

- Distribution capacity expansion could present additional costs. Areas that should be assessed are: (a) high power charging of light-duty EVs (at 150kW and above), (b) high-power charging of medium- and heavy-duty vehicles (potentially at over 1 MW), (c) legacy infrastructure constraints in dense urban areas, and (d) low-power charging of light-duty EVs on distribution systems.
- Transmission constraints must be assessed. It is acknowledged that transmission expansions must be deliberate as these investments in the U.S. power system are expensive and time consuming.
- Ramping capabilities of the generating fleet and spinning reserve requirements of the bulk power system should be considered for EVs at Scale.
- Medium- and heavy-duty vehicles account for 29% of U.S. on-road transportation fuel use. Analysis of medium- and heavy- duty EV market growth scenarios are needed to assess the impact on energy generation and generation capacity.

Although these issues vary geographically and are use-case specific, they do not undermine the overarching conclusion that EVs at Scale will not pose significantly greater challenges than past evolutions of the U.S. electric power system. This next evolution can be managed with proper planning for EV penetration and the resulting charging demand to support a growing light-duty EV fleet. The U.S. Department of Energy is funding several studies at the national laboratories to address the challenges noted above that are outside of the scope of this report. These studies are noted along with the challenges they are tackling to enable charging of EVs at Scale in the evolving electric grid.

Introduction

Electric vehicles (EVs) can meet U.S. personal transportation needs using domestic energy resources while at the same time offering local air quality benefits. However, wide scale light-duty EV adoption will necessitate assessment of and possibly modification to U.S. electric power generation and distribution systems. As used in this report, the term EV refers to both light-duty battery electric vehicles (BEVs) and light-duty Plug-In Hybrid Electric Vehicles (PHEVs) but excludes fuel cell electric vehicles and hybrid electric vehicles that do not plug in to charge the battery. The Grid Integration Tech Team (GIT) and Integrated Systems Analysis Tech Team (ISATT) of the U.S. DRIVE Partnership examined a range of EV market penetration scenarios (low, medium, and high) from the Electric Power Research Institute (EPRI) in developing this report. For each scenario, implied changes in U.S. electric power system energy generation and generation capacity are quantified and compared to historical growth.

The objective of the report is to gauge the sufficiency of both energy generation and generation capacity in the U.S. electric power system to accommodate the growing fleet of light-duty EVs. The growing EV adoption, referred to here as EVs at Scale, is anticipated to become an increasingly important demand on the system in the near future. This report considers historical trends of electricity generation and compares it with projections of EV adoption rates. The report is based on existing information regarding the electric grid, EV fleet, and EV sale projection scenarios. The comparison illustrates that there have been sustained periods of time in the past where more growth in demand was accommodated than the ranges of expected additional electricity consumption and peak demand associated with the future EV market scenarios considered here.

The first section of the report defines future U.S. EV market penetration scenarios (the low, medium, and high cases). The second section provides a historical overview of energy generation (i.e. the total amount of electrical energy, commonly expressed in megawatt-hours (MWh), produced at the generating stations) and energy generation estimates for EVs at Scale. The next two sections cover regional demand recorded in different parts of the U.S. for summer and winter and their typical characteristics and generation capacity (i.e., the maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, adjusted for ambient conditions). Load impacts for the EVs at Scale scenarios are also shown. These sections represent the heart of this report, providing a comparison of the incremental electricity generation and generation capacity associated with future EV scenarios and the respective historical increases in each. The final section offers concluding remarks and a qualitative discussion of potential challenges posed by high power charging, medium- and heavy-duty vehicle charging, and legacy infrastructure in dense, urban areas. Detailed analysis on these final topics is outside the scope of this report.

U.S. EV Market Penetration Scenarios

While the future of the U.S. light-duty EV market is uncertain, studies from various sources have offered projections. For the analysis in this report, the Electric Power Research Institute (EPRI, a U.S. DRIVE member), developed a series of three market projection scenarios, building off of actual EV sales through 2016 [2]. The EV market growth in the three scenarios—

henceforth called the low, medium, and high scenarios—are depicted in Figure 1, and are informed by the following previous estimates:

- the National Research Council of the National Academies of Science, Engineering, and Medicine [3];
- the National Renewable Energy Laboratory [4];
- the Energy Information Administration [5], [6], [7] and [8];
- Navigant Research [9], [10]; and
- Bloomberg New Energy Finance [11].

As Figure 1 shows, EV sales in 2030 are estimated to total 320 thousand (2% of new vehicle sales), 2.2 million (12%), and 6.8 million (40%) in the low, medium, and high scenarios respectively. These scenarios result in a total EV fleet size (i.e., cumulative vehicle sales) of 3 million (1% of the total passenger vehicle fleet), 14 million (5%), and 40 million (15%) vehicles by 2030, respectively.

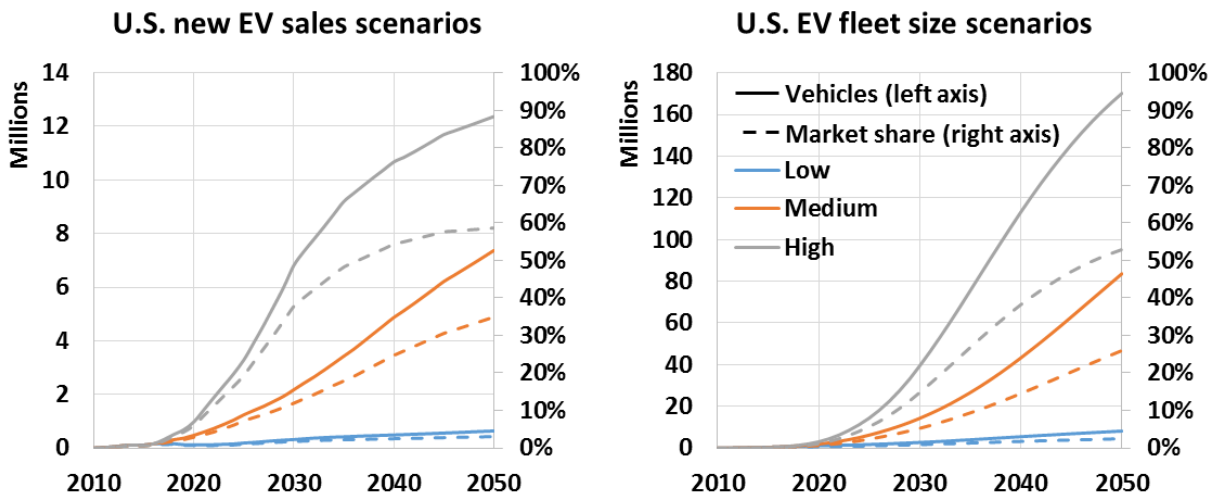


Figure 1 EPRI low, medium, and high PEV market penetration scenarios, shown both as annual sales (at left) and total PEV fleet size (i.e., cumulative vehicles in service, at right). Solid lines correspond to number of vehicles (left axes) and dotted lines correspond to sales shares (right axes).

While both annual and cumulative sales estimates in all three scenarios are projected from actual sales data through 2016, as is shown in Figure 2, the actual sales from 2016 to 2018 are included for comparison.

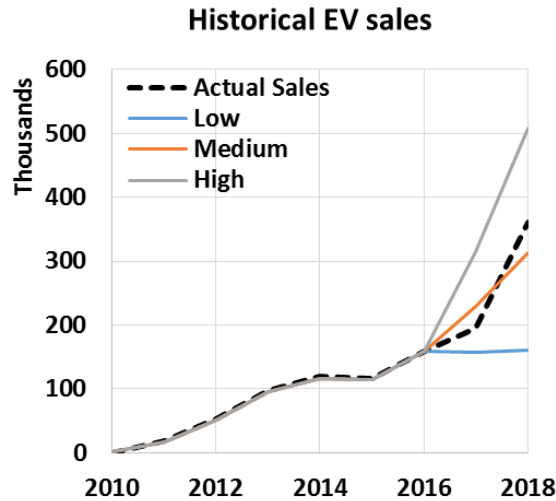


Figure 2 EPRI low, medium, and high scenario forecasts compared to actual EV sales.

Energy Generation for EVs at Scale

In the past 20 years, the annual growth in energy generation (i.e. total electricity consumption, or load, and system losses) has averaged 30 TWh, and while the last decade has seen less than 5 TWh added each year, historically, there have been periods when the grid added nearly 100 TWh per year [12]. Periods of highest energy generation growth included expansions to baseload generation from nuclear and fossil sources at a time when the policy environment allowed for necessary investment. As historical data since 1950 (Figure 3) illustrates, annual growth peaked near 100 TWh, first over the period 1970–1975, corresponding to the electrification of homes in the U.S. and the addition of household appliances (e.g., refrigerators and clothes washers and dryers), and again over the period 1990–1995, due to the widescale installation of air conditioning. For context, both refrigerators and clothes dryers achieved 50–55% market share roughly 20 years after market introduction, roughly consistent with the high EV scenario considered here; whereas, clothes washers and central air conditioning achieved 15–20% market share 20 years after market entry, closer to the medium EV scenario considered here [13].

As Figure 3 illustrates, the U.S. electric power system has evolved over time to accommodate new energy demand. A series of straightforward assumptions and unit conversions allows us to place additional potential charging load from future EVs in the context of this historical data. Assuming each EV travels 12,000 miles annually, consuming approximately 300 Wh/mi of AC energy [1], and assuming 4.9 % system losses [14] for transmission and distribution, then each EV will require 3.8 MWh/year of energy generation. For the 2030 low, medium, and high EV sales scenarios, this translates into 1, 8, and 26 TWh of incremental energy generation, respectively. These increases in energy generation are relatively small compared to the 100 TWh range shown in Figure 3. As the figure confirms, historically, there have been periods of time when the grid added in excess of 25 million vehicles-worth of generation per year, the equivalent of roughly 150% of annual new light-duty vehicles sales in the U.S. today [15].

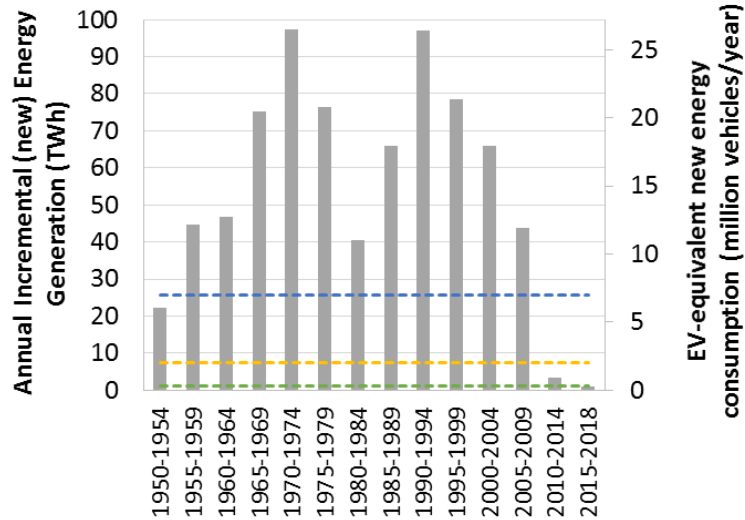


Figure 3 Historical data showing U.S. annual incremental (new) energy generation over time, averaged in 5-year increments. Energy generation associated with EV sales shown for the 2030 low, medium, and high scenarios considered at 1, 8, and 26 TWh, respectively, for context. [2]

While discussion of the historical evolution of the U.S. electric power system provides insight into past growth of energy generation, the EV market penetration scenarios can be used to project 2020 to 2050 EV charging energy generation requirements. The incremental energy generation requirements from the three EV scenarios are shown in Figure 4. The high scenario sees a peak in the 2035-to-2039 period while the medium scenario peak occurs later in the 2045-to-2049 period with about 27 TWh and 15 TWh of new annual generation, respectively. The faster adoption of EVs in the high scenario when compared to the medium scenario results in greater incremental energy generation, even when comparing 2035 (high scenario) and 2050 (medium scenario) where both scenarios have EVs at roughly 45% of the fleet. Also note that as fleet share begins to saturate in the high scenario around 2040, the incremental energy generation begins to subside.

As the EV market develops, it is expected that future advances in EV technology will enable greater efficiency and lower energy consumption per mile. At the same time, the current consumer trend toward larger vehicles, which typically have lower efficiency, suggests increasing energy consumption per mile. It is hard to predict which of these trends will dominate. The future trend for per-vehicle annual travel may also change as a result of disruptive trends or technologies such as autonomously driven vehicles. Hence, we acknowledge that there's uncertainty in future per-vehicle annual electricity consumption.

Further, it should be noted that this historical comparison overlooks factors that have changed energy generation over the years, such as market decoupling of energy supply from vertically integrated utilities. These periods of high growth in generation correspond to times in which the installation of large baseload generation (fossil and nuclear) were common. This may not be the case in the future, and other factors such as how ready utilities are to install new capacity, sufficient utility labor, capital, land use, environmental regulations, reliability requirements, and the policy environment should all be considered.

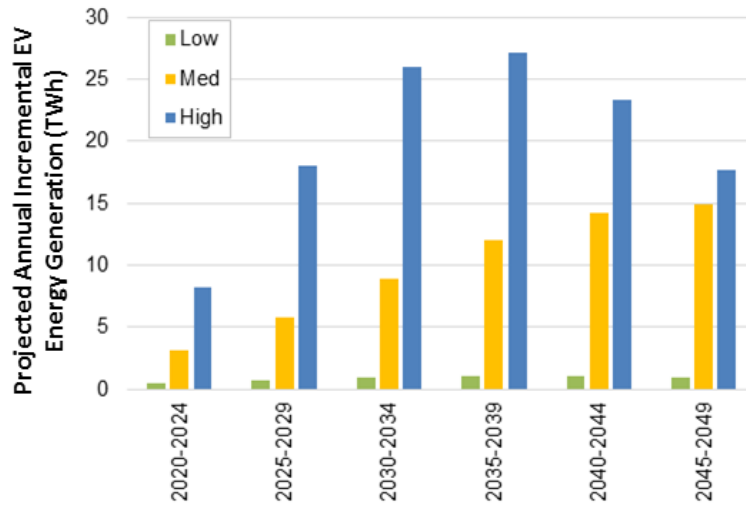


Figure 4 Projected annual incremental energy generation to support EVs, averaged to five-year periods for the low, medium, and high market penetration scenarios.

Regional Demand

Electricity consumption or demand at the bulk interconnection level is the aggregation of diverse loads connecting to distribution and transmission networks. This aggregate demand includes residential, commercial, and industrial consumption. In the U.S., balancing authorities manage the electric power system, including generation and capacity, based on demand forecasts. Actual demand values are measured and recorded for post processing to improve forecasting and for market purposes. There are many factors that influence the magnitude and characteristics of demand, including energy efficiency measures, types of appliances, distributed energy resources, weather, time of day, season of year, and special days (weekends and holidays).

To provide context, demand curves from the California Independent System Operator (CAISO), New York Independent System Operator (NYISO), Electric Reliability Council of Texas (ERCOT), and Midcontinent Independent System Operator (MISO), are shown in Figure 5. The balancing authority areas for CAISO, NYISO, and ERCOT roughly represent the geographic boundaries of California, New York, and Texas. MISO covers 15 states and the Canadian province of Manitoba, stretching across the center of the U.S. from the Midwest into the South-Central States. At an hourly resolution, the daily load is averaged for the months of January (winter) and July (summer) 2019. Observations regarding the daily variation of demand are:

- On-peak hours are typically observed during early morning (6-10 AM) and early evening (5-9 PM).
- Multiple ramps tend to occur during the day between on-peak and off-peak hours for the Winter demand profiles due to an additional midday off-peak period.
- Higher system demand occurs during the summer.

Finer details and observations regarding power and energy requirements and their daily demand variations can be drawn. These representative plots of monthly averages are not intended to capture monthly, seasonal, and annual load variations.

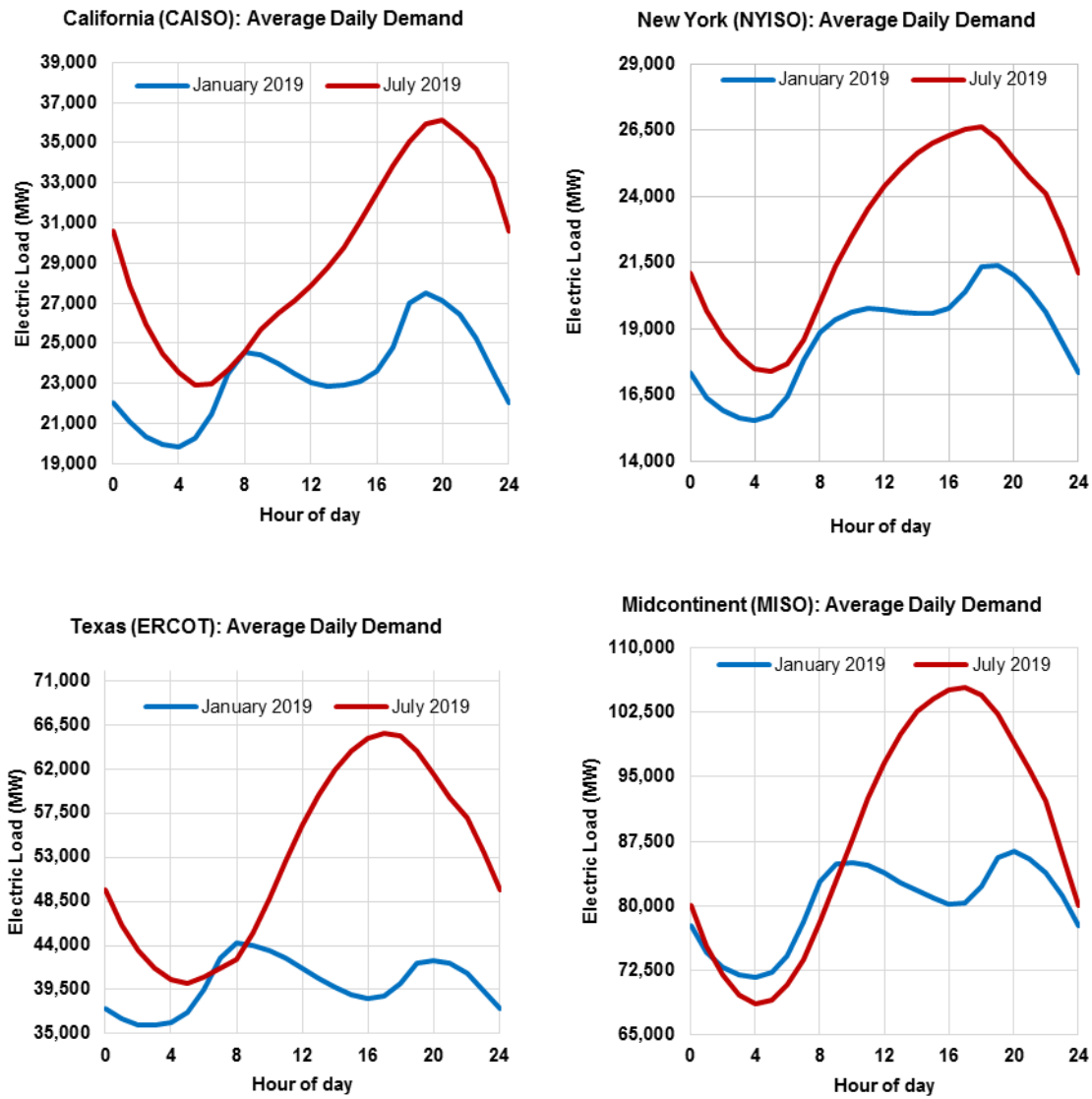


Figure 5 Average daily demand for January and July 2019 recorded in California, New York, Texas, and Midcontinent (parts of the Midwest and South-Central States) [16], [17], [18], [19].

EVs charging at home, at work, or even at a high-power charging travel plaza contribute to overall demand on the electric grid. There are numerous factors such as user charging needs, charge rates, battery size, and charger types that determine the aggregate demand from EV charging on the grid. The aggregation and management of EV charging load within the grid system must factor in observations from the demand curves presented in Figure 5. In a nutshell, EV charging at off-peak hours is generally beneficial and can help reduce the impact of charging on generating capacity. EV charging at peak hours is anticipated to be more expensive, as additional generation capacity may be required, and deferring to off-peak hours would imply cost

savings. Managed charging of EVs at Scale may present an opportunity for all ratepayers to see lower costs from increased system utilization, where the same fixed assets could be used for additional energy generation (sales).

Aggregate charging demand, or the resultant charging demand as a function of infrastructure availability, travel behavior, and vehicle design (range, charging power), is important for an overall understanding of grid integration of EVs. There can be significant variations in the aggregate demand and its characteristics based on whether EVs charge at home, workplace, or commercial locations. EV charging demand aggregation can potentially have a detrimental impact on grid operation by augmenting the existing peaks observed in Figure 5. Two scenarios which are detrimental to system demand are ‘uncontrolled’ and ‘maximum delay’ of EV charging. Uncontrolled charging represents the case where EVs charge immediately at full power once connected and continue until completely charged. Maximum delay represents the case where demand is shifted into the latest period that ensures the EV receives a complete charge before departure. These two cases represent both ends of the spectrum of vehicle charging.

The aggregate charging demand profiles generated by NREL’s EVI-Pro model² for the adoption of 100,000 EVs are shown in Figure 6. The power for Level 2 (L2) charging of 60% of these EVs is at 6.6 kW while the power for the remaining 40% is at 10 kW. The two charging conditions simulated here are uncontrolled and maximum delay. Both weekday and weekend profiles are generated and reveal drastically different aggregate demand from EV charging. For instance, the weekday uncontrolled charging creates an evening charging peak of approximately 150 MW from 6 to 10 PM, whereas the maximum delay creates an early morning charging peak of approximately 205 MW from 6 to 10 AM. These aggregate peaks translate to 1.50 kW-per vehicle and 2.05 kW-per vehicle, respectively.

While Figure 6 and the preceding text discuss EV demand impacts of both ends of the spectrum, in reality it is reasonable to consider a scenario where managed charging means very little new capacity for EVs is required. In fact, not only can managed charging diminish EV peak demand impacts, but it could offer broader monetary benefits to the system as a whole.

Managed charging is a critically important consideration in the ultimate grid impact of EVs at Scale. Even without managed charging, EVs at Scale can be accommodated through capacity expansions based on traditional utility experience and management; however, planning and investing without considering managed charging may lead to a higher-cost infrastructure.. There are fundamental differences in the design and functioning of the transmission and distribution systems throughout the U.S. For example, the electric power systems in temperate locations are usually built for seasonal peaks with significant unused generation capacity much of the year. Hence, the technical and economic challenges will vary for different regions within the U.S. and are based on the numerous factors, including distribution system capacity, EV infrastructure, charging power, and weather. Managed charging or smart charge management of EVs can enable multiple advantages such as lowered charging costs, improved utilization of existing grid assets, and deferred cost of expansions.

² NREL’s EVI-Pro model estimated a per-vehicle peak power impact of 1.05 kW in a national analysis and a range from 0.65 to 1.8 kW in a series of geographically specific analyses [23]: 0.65-0.88 kW in Massachusetts [31], 0.65-1.8 kW in Columbus, OH [24], 0.75 kW in California [32], and 0.92 kW in Maryland [30].

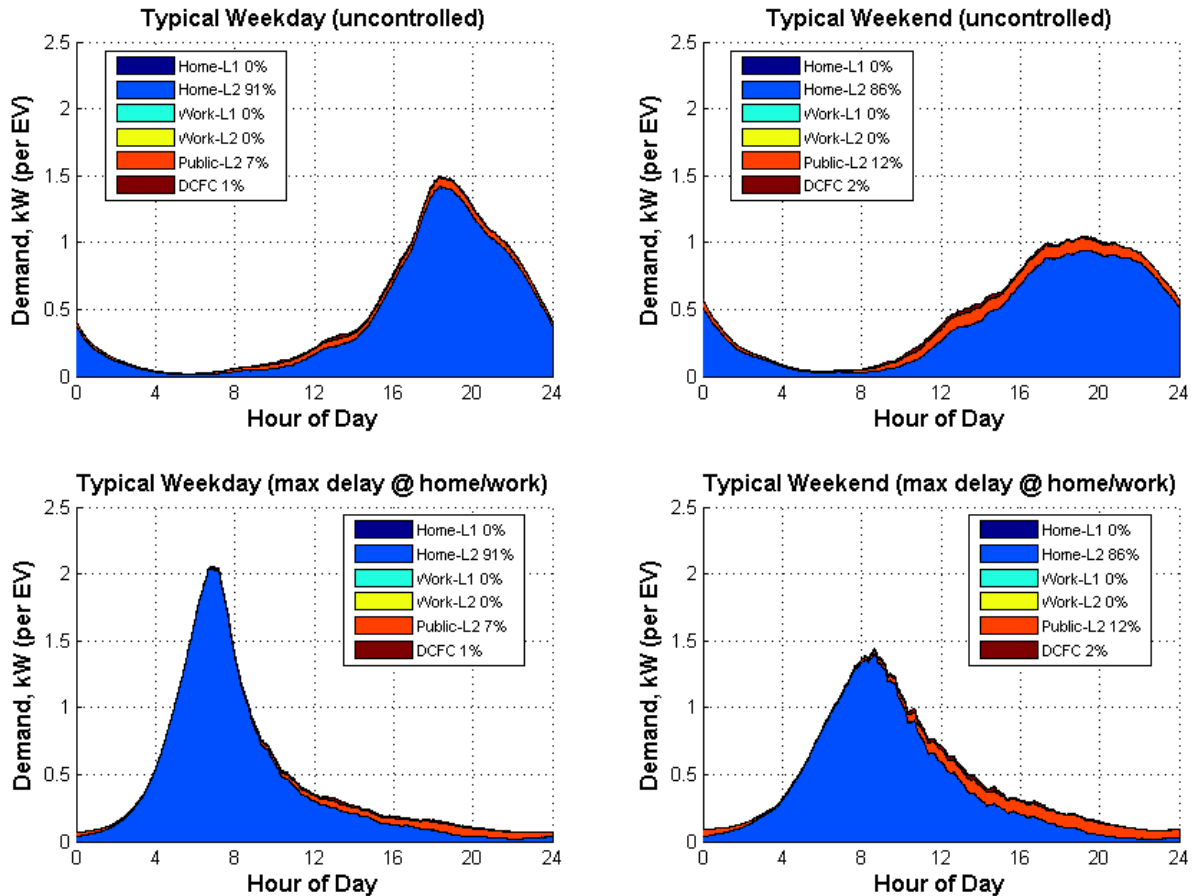


Figure 6 Aggregate demand profiles for 100,000 EVs under weekday and weekend uncontrolled and maximum delay charging conditions

The U.S. Department of Energy has several ongoing managed charging projects to study mitigation of potential adverse impacts and maximization of potential benefits:

- The Smart Vehicle Grid Integration (VGI) project, led by Argonne National Laboratory, in cooperation with Idaho National Laboratory. This project is taking a vehicle-up approach to charge management from the sub-second to minutes time scale to enable grid services such as load management, voltage control, and frequency regulation by utilizing high speed communications and charge controls, combined with grid sensing and measurement and an optimization tool.
- The RECHARGE project led by the National Renewable Energy Laboratory, in partnership with Sandia National Laboratory and Idaho National Laboratory. RECHARGE takes a utility-down approach to charge management from the minutes to the multiple-hour time scale to maximize grid operating efficiencies and resiliency using charge management controls and integration of distributed energy resources while still meeting the recharging needs of the EV owner. RECHARGE is performing a detailed assessment of EV impacts on the distribution networks of Minneapolis and Atlanta.

- ‘Scalable Electric Vehicle Smart Charging Using Collaborative Autonomy’ is a project at Lawrence Livermore National Laboratory. This project is developing a distributed computing tool that will result in charge management decisions generated collaboratively among a set of grid node devices versus a centralized processing unit.
- Pacific Northwest National Laboratory is working on a project to quantify transmission and distribution impacts of charging EVs at Scale.

Generation Capacity for EVs at Scale

Annual net generation capacity additions since 1990 have ranged from near zero to over 50 GW [20]. Even excluding intermittent renewables (i.e., solar and wind), dispatchable capacity (biomass, coal, hydroelectric, natural gas, nuclear, and petroleum) alone has grown from near zero to just over 50 GW per year, and renewables have added up to another 15 GW annually. Figure 7 depicts both new dispatchable and total (dispatchable plus intermittent renewable) capacity additions per year.

As was the case for annual energy generation growth, and as Figure 7 illustrates for generation capacity, the grid has evolved over time to accommodate new loads. Similar to the discussion of annual energy generation growth in the earlier section, a series of straightforward assumptions enables this presentation of historical data to offer context on the future incremental EV charging demand. Charging analysis using the EVI-Pro model (shown in Figure 6) identified an aggregate per-vehicle power of 2.05 kW. Using this aggregate per-vehicle power and the low, medium, and high EV scenarios in 2030 leads to generation capacity increments of 0.7, 4.5, and 14 GW, respectively. Similarly, translating the ~10 GW recent dispatchable capacity installations shown in Figure 7 (~10 GW in 2006, 2007 and 2013) yields a range of 4 to 5 million equivalent new EVs (2% of today’s U.S. light-duty fleet) added to the grid per year.

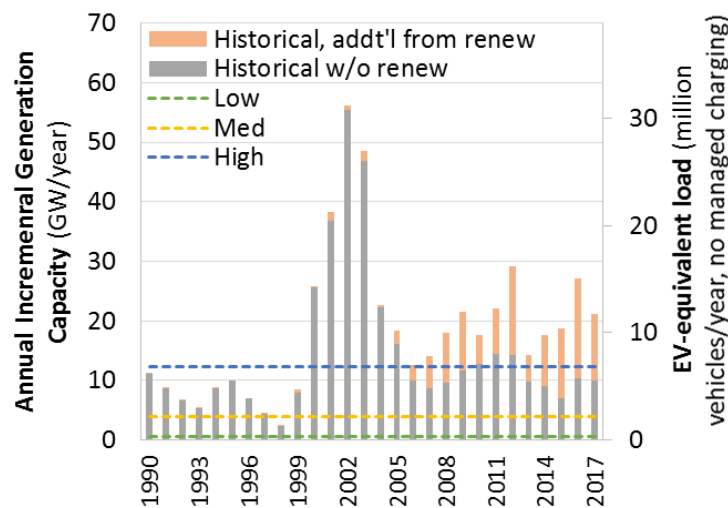


Figure 7 U.S. annual incremental (new) grid capacity from 1990 to 2017. The additional demand associated with EV sales for the low, medium, and high scenarios considered at 0.7, 4.5, and 14 GW, respectively, for context [22].

Within the last decade, the U.S. electric power system added an average dispatchable generating capacity of 12 GW per year, with years that exceeded 25 GW when including intermittent resources as shown in Figure 7. This recent experience of capacity growth may provide a more relevant view of future generation capacity expansion. The Annual Energy Outlook for 2019 shows that the fraction of intermittent generation is expected to increase from 21.3% in 2019 to 32.4% in 2050 with an average annual incremental capacity expansion of 12 GW [21]. The projected incremental generation capacity projected for both intermittent and renewable are shown in Figure 8.

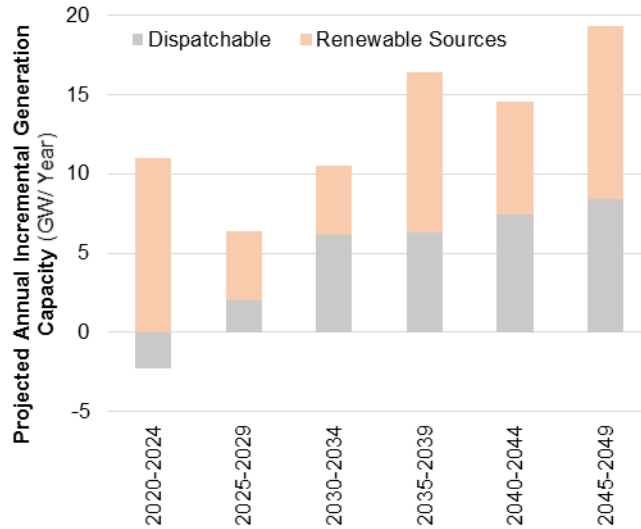


Figure 8 U.S. projected annual incremental generation capacity for 2020 to 2050 [21].

It is critically important to acknowledge that aggregate per-vehicle power impact is a function of both the number of vehicles and how those vehicles charge. For example, even with the assumption of a diversified load without managed charging, EVI-Pro modeling results have estimated per-vehicle peak-load impacts ranging from as low as 0.65 kW [23] to as high as 1.8 kW [24], with differences driven by factors such as vehicle fleet composition (i.e., whether vehicles are compacts, SUVs, or a combination) and travel behavior, which can vary by geography. Figure 9 shows the projected annual incremental generation capacity needed to support EV charging demand under the low, medium and high scenarios. The high scenario sees a peak in the 2035-to-2039 period while the medium scenario peak occurs later in the 2045-to-2049 period with about 15 GW and 8.5 GW of new generation capacity, respectively. The high scenario exceeds the historical average dispatchable capacity expansion of 12 GW observed over the last decade. This represents the ‘maximum delay’ aggregate charging scenario under high EV market penetration, representing the maximum capacity requirement among cases considered in this report. This represents a worst-case unmanaged charging scenario starting in 2030, which is unlikely to occur given the current work on managed charging solutions and the monetary benefits of their implementation. Further, it should be noted that installation of intermittent resources over the last decade brings the average capacity installation to 20 GW.

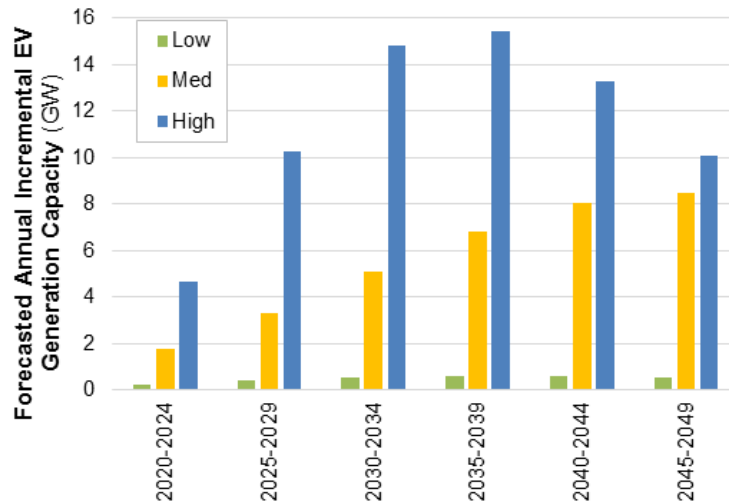


Figure 9 Projected annual incremental generation capacity to support EV energy consumption averaged to five-year periods for the low, medium, and high adoption market penetration scenarios.

Concluding Observations and Potential Future Challenges

The data presented in this report offers an illustrative context showing that there have been sustained periods of time where the grid accommodated more demand than the expected additional electricity consumption associated with light-duty EV market growth scenarios ranging from 320 thousand to 7 million new EVs annually in 2030. At times, the grid has accommodated energy generation and generation capacity equivalent to as many as 25 million new EVs per year, even without consideration of managed charging. This analysis also points out that growth in incremental energy generation associated with the future EV market scenarios considered here may reverse the trend over the last 10 years of near-zero growth. In addition, within the last decade, the U.S. electric power system has added on average a dispatchable generating capacity of only 12 GW per year, with years that exceeded 25 GW when including intermittent resources. This dispatchable generating capacity is equivalent to the aggregate demand of nearly 6 million new light duty EVs per year. Accordingly, with adequate utility resources and preparedness to install new capacity, adequate energy generation and generation capacity are expected to be able to support a growing EV fleet as it evolves over time, even in a future characterized by relatively high EV market. It is also important to note that non-technical factors such as policy, regulatory framework, and economic constraints may have changed over the period corresponding to the historical data presented here and may affect future energy generation and generation capacity expansion.

While this summary report focuses on the impacts of light-duty vehicles on energy generation and generation capacity, it acknowledges several potential challenges at the distribution level. Consideration of the following warrant additional analysis:

- Distribution capacity expansion could present additional costs. Areas that should be assessed are: (a) high power charging of light-duty EVs (at 150kW and above), (b) high-power charging of medium- and heavy-duty vehicles (potentially at over 1

- MW), (c) legacy infrastructure constraints in dense urban areas, and (d) low-power charging of light-duty EVs on residential circuits.
- Transmission constraints must be assessed. It is acknowledged that transmission expansions must be deliberate as these investments in the U.S. power system are expensive and time consuming.
 - Ramping capabilities of the generating fleet and spinning reserve requirements of the bulk power system should be considered for EVs at Scale.
 - Medium- and heavy-duty vehicles account for 29% [25] of U.S. on-road transportation fuel use. Analysis of medium- and heavy- duty EV market growth scenarios are needed to assess the impact on energy generation and generation capacity.

Although these issues vary geographically and are use-case specific, they do not undermine the overarching conclusion that EVs at Scale will not pose significantly greater challenges than past evolutions of the U.S. electric power system. This next evolution can be managed with proper planning for EV penetration and the resulting charging demand to support a growing light-duty EV fleet. The U.S. Department of Energy is funding several studies at the national laboratories. These studies are noted along with the challenges they are tackling to enable charging of EVs at Scale in the evolving electric grid.

References

- [1] Elgowainy, "Cradle-to-Grave Lifecycle Analysis of U.S. Light-Duty Vehicle-Fuel Pathways: A Greenhouse Gas Emissions and Economic Assessment of Current (2015) and Future (2025-2030) Technologies," Argonne National Laboratory, Chicago, 2016.
- [2] Electric Power Research Institute, "Plug-in Electric Vehicle Market Projections: Scenarios and Impacts," EPRI Report #3002011613, <https://www.epri.com/#/pages/product/3002011613/>, 2017.
- [3] National Research Council, "Overcoming Barriers to Electric-Vehicle Deployment," National Academies of Science, Engineering, and Medicine, Washington, D.C., 2015.
- [4] M. Trieu, P. Jadun, J. Logan, C. McMillan, M. Muratori, D. Steinberg, L. Vimmerstedt, R. Jones, B. Haley and B. Nelson, "Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States," National Renewable Energy Laboratory, Golden, CO, 2018, NREL/TP-6A20-71500.
- [5] U.S. Energy Information Administration, "Annual Energy Outlook 2012," U.S. Department of Energy, Washington DC, 2012.
- [6] U.S. Energy Information Administration, "Annual Energy Outlook 2015," U.S. Department of Energy, Washington, DC, 2015.
- [7] U.S. Energy Information Administration, "Annual Energy Outlook 2016," U.S. Department of Energy, Washington, DC, 2016.
- [8] U.S. Energy Information Administration, "Annual Energy Outlook 2017," U.S. Department of Energy, Washington, DC, 2017.
- [9] Navigant Research, "Market Data: EV Market Forecasts," Navigant Research, 2015.
- [10] Navigant Research, "Market Data: EV Market Forecasts," Navigant Research, 2016.
- [11] Bloomberg New Energy Finance, "Electric Vehicle Outlook," Bloomberg, New York, 2017.
- [12] Energy Information Administration, "Monthly Energy Review," 2018. [Online]. Available: <https://www.eia.gov/totalenergy/data/monthly/>. [Accessed 6 September 2019].
- [13] D. Comin and B. Hobijn, "Cross-country Historical Adoption of Technology (CHAT) dataset," National Bureau of Economic Research (NBER), 2009. [Online]. Available: <http://www.nber.org/data/chat/>. [Accessed 6 September 2019].

- [14] U.S. Energy Information Administration, "How much electricity is lost in electricity transmission and distribution in the United States?," 9 January 2019. [Online]. Available: <https://www.eia.gov/tools/faqs/faq.php?id=105&t=3>. [Accessed 21 August 2019].
- [15] Energy Information Administration (EIA), "Annual Energy Outlook," Washington, D.C., 2019.
- [16] California Independent System Operator, "California ISO - Reliability Requirements," [Online]. Available: <http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx#Historical>. [Accessed August 2019].
- [17] New York Independent System Operator, "Load Data- NYISO," [Online]. Available: <https://www.nyiso.com/load-data> . [Accessed August 2019].
- [18] Electric Reliability Council of Texas, "Hourly Load Data Archives," [Online]. Available: http://www.ercot.com/gridinfo/load/load_hist/. [Accessed August 2019].
- [19] Midcontinent Independent System Operator, "MISO Market Data," [Online]. Available: [https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3ADaily%20Forecast%20and%20Actual%20Load%20by%20Local%20Resource%20Zone%20\(xls\)&t=10&p=0&s=MarketReportPublishe](https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary%2FMarketReportName%3ADaily%20Forecast%20and%20Actual%20Load%20by%20Local%20Resource%20Zone%20(xls)&t=10&p=0&s=MarketReportPublishe). [Accessed August 2019].
- [20] Energy Information Administration, "Electric Power Annual," 2017. [Online]. Available: <https://www.eia.gov/electricity/annual/>. [Accessed 6 September 2019].
- [21] U.S. Energy Information Administration, "Annual Energy Outlook 2019- Table 9 Electricity Generating Capacity," [Online]. Available: <https://www.eia.gov/outlooks/aeo/>. [Accessed September 2019].
- [22] Electric Power Research Institute, "(EPRI, 2018)," 2018.
- [23] E. Wood, C. Rames, M. Muratori, S. Raghavan and M. Melaina, "National Plug-in Electric Vehicle Infrastructure Analysis," U.S. Department of Energy, DOE/GO-102017-5040, <https://www.nrel.gov/docs/fy17osti/69031.pdf>, 2017.
- [24] E. Wood, C. Rames, M. Muratori, S. Raghavan and S. Young, "Charging Electric Vehicles in Smart Cities: An EVI-Pro Analysis of Columbus, Ohio," National Renewable Energy Laboratory, NREL/TP-5400-70367, <https://www.nrel.gov/docs/fy18osti/70367.pdf>, 2018.
- [25] U.S. Energy Information Administration, "Annual Energy Outlook 2019: Table 36 Transportation Sector Energy Use by Mode and Type," 2019. [Online]. Available: <https://www.eia.gov/outlooks/aeo/>. [Accessed September 2019].

- [26] North American Electric Reliability Corporation, "Glossary of Terms Used in NERC Reliability Standards," 12 August 2019. [Online]. Available: https://www.nerc.com/files/glossary_of_terms.pdf. [Accessed 22 August 2019].
- [27] U.S. Energy Information Administration, "Glossary," U.S. Energy Information Administration, 2019. [Online]. Available: <https://www.eia.gov/tools/glossary/>. [Accessed 22 August 2019].
- [28] California Air Resources Board, "Battery Electric Truck and Bus Energy Efficiency Compared to Conventional Diesel Vehicle," 2018.
- [29] Alternative Fuels Data Center, "Average Annual Vehicle Miles Traveled of Major Vehicle Categories," U.S. Department of Energy, December 2018. [Online]. Available: <https://afdc.energy.gov/data/>. [Accessed 2019 August 16].
- [30] M. Moniot, C. Rames and E. Wood, "Meeting 2025 Zero Emission Vehicle Goals: An Assessment of Electric Vehicle Charging Infrastructure in Maryland," National Renewable Energy Laboratory, NREL/TP-5400-71198, <https://www.nrel.gov/docs/fy19osti/71198.pdf>, 2019.
- [31] E. Wood, S. Raghavan, C. Rames, J. Eichman and M. Melaina, "Regional Charging Infrastructure for Plug-in Electric Vehicles: A Case Study of Massachusetts," National Renewable Energy Laboratory, NREL/TP-5400-67436, <https://www.nrel.gov/docs/fy17osti/67436.pdf>, 2017.
- [32] A. Bedir, N. Crisostomo, J. Allen, E. Wood and C. Rames, "California Plug-in Electric Vehicle Infrastructure Projections: 2017-2025," California Energy Commission., Publication Number: CEC-600-2018-001, 2018.