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Electric Vehicles and the Grid: The Impact of EVs on Power Demand, Peak Load and Electric Energy Storage -- and the Impact of the Grid on EVs

Integrating the growing fleet of electric cars, trucks and buses will present important commercial opportunities and critical technical challenges for the electric utility industry. We estimate that a fully electrified vehicle fleet would increase U.S. power consumption by a third, accelerating the growth of utilities' volume sales and, in states without decoupling, utility revenues as well. The grid upgrades required to accommodate the charging requirements of this fleet could add to rate base growth in the longer term. As yet uncharted is how the grid will supply electric vehicles' potentially huge charging demand, and capitalize on their equally large capacity for storage. Utility regulators will play a central role in shaping the industry's response, and in so doing may set parameters for the integration of electric vehicles on the grid that will affect the scale of the fleet, how owners use their vehicles and the design of the vehicles themselves.

Portfolio Manager's Summary

- **The addressable market for electric vehicle batteries will dwarf the market for storage on the grid, and could have a much greater impact on the bulk power system.**
  - The U.S. vehicle fleet comprises 260 million cars, trucks and buses. If each were equipped with a battery with a range of 300 miles per charge, and assuming average fleet energy efficiency of 2.6 miles per kWh, the potential scale of the U.S. EV market for batteries can be estimated at 30 billion kWh or 30,000 GWh (260 million vehicles x 300 miles per charge/2.6 miles/kWh).
  - This is more than 250x the likely addressable market for utility scale batteries, which we estimate at less than 115 GWh. (See our April 18th note, *How Big is the Market for Batteries on the Grid?*.)
- **The electrification of the vehicle fleet will create important commercial opportunities for electric utilities and competitive generators, as well as critical technical challenges that will require a considered and comprehensive regulatory response.**
  - **We estimate that the electrification of the entire 260 million U.S. vehicle fleet will increase power demand by a third.** This increase in demand would be supplied by those generating units currently operating below their maximum capacity, and thus could benefit combined cycle gas and coal fired power plants, whose capacity factor averages only 55%. **The estimated increase in electricity demand is equivalent to 50% of the combined output of the U.S. coal and gas fired fleets in 2016, enough to raise the capacity factor of these plants above 80%. This will be offset, at least in part, by the continued growth of renewable energy over the decades it will take to electrify the U.S. vehicle fleet.**
  - **The power demand of a fully electrified vehicle fleet would be so large that, unless staggered over the low demand hours of the day, it would overwhelm the generation capacity of the grid**. Were an entirely electrified U.S. vehicle fleet to charge its batteries simultaneously, serving the charging load alone would require ~1,840 GW of power,

approximately twice the dispatchable generation capacity of the United States. By contrast, if the charging of the EV fleet were staggered between midnight and 6:00 AM, when power demand is lowest, an increase in U.S. generation capacity of just 190 GW, or 20% of installed dispatchable capacity, would be sufficient (**Exhibit 6**).

- **As the electric vehicle fleet expands in size, therefore, electric utilities and state regulators will be forced to implement legal and regulatory frameworks that avoid the need for a huge expansion of generation capacity. Critical will be utility-controlled staggering of nighttime vehicle charging, complemented by rate structures to shape EV charging load during daytime hours**, including, eventually, dynamic, localized real-time pricing. **These legal and regulatory frameworks could affect the growth rate of the EV fleet, how owners use their vehicles, and the design of the vehicles themselves.**
- **As a rule of thumb, we see a tipping point for regulators and utilities to act when the number of electric vehicles, measured in units, approaches 40x a region's peak load, measured in MW**.
  - Power grids generally maintain an excess of dispatchable capacity over peak demand (reserve margin) of 15% to ensure the continuity of power supply in the event of a major equipment failure. In California, if charging demand is not controlled, this margin of safety could be completely eroded by 1.84 million EVs, or 40x the grid's peak demand of 46,000 MW.
  - California's 2016 peak power demand of 46,000 MW was reached at 6:00 PM on a July evening. Early evening is also the time when EV owners are likely to be returning home from work and plugging in their cars to recharge. Once California's light duty electric vehicle fleet reaches 1.84 million, or 6% of the state's current vehicle fleet, the aggregate load of just 75% of these EVs using 5 kW chargers would be 6.9 million kW (1.84 million EVs x 75% x 5 kW) or 6,900 MW. This is equivalent to 15% of California peak demand of 46 GW, consuming its reserve margin.
- **In the near term, the rollout of electric vehicles will accelerate the rate base growth of distribution utilities, and particularly so in California, home to half the national EV fleet.** In California, utilities have begun to install charging stations at workplaces and retail centers, but much more significant will be the upgrades required to residential transformers and distribution circuits to meet the nighttime load for vehicle charging. The far larger and more concentrated loads caused by fast charging stations and the charging of truck and bus fleets would require even more grid hardening.
- **Over the longer term, charging a fully electrified vehicle fleet will require substantial additions to installed generating capacity, as well as a smarter grid capable of real-time monitoring and communications to manage and mitigate potentially massive spikes in demand.**
- **Eventually, the electric vehicle fleet could grow to represent a huge repository of stored electrical energy, especially in light of the low average daily utilization rate of the vehicle batteries (~10%).**
  - If 10% of the U.S. fleet of 260 million vehicles were electrified, and capable of supplying the grid using two-way, 5 kW chargers, these 26 million vehicles could supply 130 million kW or 130 GW of power to the grid -- equal to 13% of U.S. dispatchable capacity and 75% of peaking capacity.
  - Over time, therefore, we see a growing incentive for state regulators to enable the bulk power system to capitalize on the huge storage capacity of the EV fleet.
- **The first distribution utilities to benefit from the investment opportunities created by electric vehicles will be EIX and PCG in California**, where state policy is to put 4.2 million EVs on the road by 2030, equivalent to one eighth of the current vehicle fleet and well above the 1.8 million vehicles we identify as a potential tipping point for the California grid. The region with the second highest EV penetration is the Pacific Northwest, partly reflecting Oregon's zero emissions vehicle (ZEV) standard. **POR and AVA stand to benefit from growth in the Northwestern EV fleet.** The EV fleet in the Northeast and Mid-Atlantic, while small currently, has grown over the last five years at an average annual rate of 144% in response to ZEV standards put in place by Maryland, New York, Massachusetts, Connecticut, Rhode Island and Vermont. **The growth of the EV fleet in the heavily populated Washington to Boston corridor will benefit ED, ES, and AGR, as well as the distribution utility subsidiaries of EXC and PEG.**

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Exhibit 1: Heat Map: Preferences Among Utilities, IPP and Clean Technology

Preferences Among Utilities, IPPs and Clean Technology			
Sector	Weighting	Favorites	Concerns
Regulated Electric Utilities	Overweight	EIX, PCG	ALE
Hybrid Electric Utilities	Neutral	EXC, NEE, PEG	D, ETR
IPPs	Underweight		NRG
Renewables	Underweight		
Yieldcos	Neutral	NEP	

Source: SSR analysis

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What is the Total Addressable Market for Electric Vehicle Batteries?

The addressable market for electric vehicle batteries in the U.S. is staggeringly large. We estimate the potential market for electric vehicle batteries at ~ 30 billion kWh (30,000 GWh) of storage capacity. The assumptions underpinning our calculations are set out in **Exhibit 2** below, and a summary explanation of our calculation follows.

We estimate the potential market for EV batteries as the product of the number of electric vehicles and the average capacity of their batteries. Assuming all 260 million vehicles in the U.S. were electrified, the maximum addressable market for electric vehicle batteries can be estimated at 260 million vehicles x 115 kWh per vehicle battery, or 30 billion kWh (30,000 GWh). We have estimated average battery capacity of 115 kWh based on amount of power required to achieve an average vehicle range of 300 miles per charge,[1] or the product of 300 miles and the average EV electricity consumption per mile.

[1] Electric drive passenger cars being offered for sale in the United States today are typically designed with ranges of <200 miles per charge, but typical gasoline powered vehicles have ranges of 300-400 miles on a

Electric drive passenger vehicles sold in the United States, such as the Nissan Leaf, can cover ~3.5 miles on a kWh of electricity. To estimate the electricity consumption per mile of an entirely electrified U.S. vehicle fleet, including trucks and buses, we compared the average fuel efficiency of the entire U.S. fleet of internal combustion vehicles (17.5 miles per gallon) to the average fuel efficiency of U.S. passenger cars (23.3 miles per gallon). Applying this ratio of 75% (17.5 mpg/23.3 mpg) to the energy efficiency of the Nissan Leaf, we calculate that the average mileage per kWh of a fully electrified U.S. vehicle fleet would be the Leaf's 3.5 miles per kWh x 75% or ~2.6 miles per kWh. A desired range of 300 miles per charge divided by 2.6 miles per kWh implies an average battery capacity of ~115 kWh.

Exhibit 2: Estimating the Addressable Market for Electric Vehicle Batteries

Vehicle-miles traveled (millions)	3,025,656
Fuel consumed (million gallons)	173,347
Miles per Gallon - Average	17.5
Miles per Gallon - Passenger Vehicle	23.2
Fleet Average MPG as % of Passenger Vehicle Average	75%
EV Miles/kWh (Nissan Leaf)	3.5
multiplied by: Fleet Avg MPG % of Passenger Vehicle Avg	75%
EV Miles/kWh - All Vehicles Estimate	2.6
Desired Range (miles)	300
divided by: EV Miles/kWh - All Vehicles Estimate	2.6
kWh per Vehicle - Average	114
Vehicles registered	260,350,938
multiplied by: kWh per Vehicle	114
divided by: kWh per GWh	1,000,000
Maximum EV Electric Storage Need - 2014 Fleet - GWh	29,662

Source: U.S. Department of Transportation, Nissan, SSR analysis

The maximum addressable market for battery storage on the grid, by contrast, is much smaller. Even if the nation's entire 175 GW peaking fleet were replaced with batteries capable of four hours of discharge, the total capacity of these batteries would be just 700 GWh or 700 million kWh (175 GW or 175 million kW x 4). The implication is the total addressable market for electric vehicles batteries, at 30,000 GWh, is over 40x the total addressable market for batteries on the grid.

However, as explained in our April 18th note, *How Big is the Market for Batteries on the Grid?*, we expect the economic market for batteries on the grid to be much smaller, at 115 GWh or less. Unless battery costs fall dramatically, regulated utilities and competitive generators will not deploy batteries as peaking capacity. Measured by the cost of energy supplied during peak hours, grid scale batteries cost 3 to 4x as much as new conventional gas fired peakers, discouraging their use by regulated utilities. And competitive generators cannot recover the cost of a battery from the arbitrage profit to be had by buying electricity off peak and selling it on peak in the wholesale power market.

single tank. We have assumed that 300 miles will, in the long run, also be the minimum desired range per charge of the vehicle fleet as a whole. Even at lower ranges, the addressable market is still massive.

Rather, we believe electric energy storage on the grid will be most attractive to transmission and distribution utilities and their regulators in states where generation has been deregulated. In these states, utilities and electricity retailers procure power for consumers in competitive wholesale markets where prices are set by the marginal cost of supply. The power supply curves in these markets tend to be extremely steep at very high levels of demand, so that small increases in demand result in disproportionate increases in the marginal cost of supply and thus in the prevailing market price of power. As a result, even small amounts of electric energy storage on the grid can significantly reduce the marginal cost of supply on peak and thus the total cost of procuring power to serve load. We calculate that, had just 500 MW of storage been deployed on the ERCOT grid over the five years from 2011 through 2015, the savings to consumers would have averaged ~$1.3 billion annually.

We believe the substantial savings to consumers from even limited amounts of grid storage will motivate regulators to encourage its deployment by utilities and their customers. The California Public Utilities Commission has required the state's investor-owned utilities to deploy 1,325 MW of storage by 2020. We expect regulators in other states that have deregulated generation to follow California's example: Massachusetts is considering policies to encourage the deployment of 600 MW of storage by 2026 and Maryland has passed a tax credit for distributed storage.

However, in the five competitive wholesale markets that serve states where generation has been deregulated, the battery capacity required to close the average daily gap between maximum and minimum demand – and thus the gap between low off-peak and high on-peak prices -- is only 29 GW. Assuming the deployment of 29 GW of batteries capable of four hours of discharge, the economic market for grid storage may be as small as only 115 GWh. Based on this assessment, the addressable market for vehicle batteries, at 30,000 GWh, would be over 250x the size of that for batteries on the grid.

How Much Electricity Would a Fully Electrified Vehicle Fleet Consume?

We can use these same data points to estimate the potential increase in electricity consumption resulting from the electrification of the entire U.S. vehicle fleet (see **Exhibit 3**). In aggregate, the U.S. vehicle fleet travels some 3 trillion miles annually. Based on the estimate we derived above of the average energy efficiency of an electrified vehicle fleet (2.6 miles per kWh), this would suggest that a fully electrified vehicle feet would consume some 1.15 trillion kWh of electricity. Adjusting for electricity losses over the charge/discharge cycle of the batteries (~10% for lithium ion batteries currently), we can estimate the total demand for electricity of a fully electrified U.S. vehicle fleet at ~1.3 trillion kWh (equivalent to 1.3 billion MWh or 1.3 million GWh). This is equivalent to 34% of the 3.8 million GWh of electricity consumed in the United States in 2014.

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Exhibit 3: Estimating the Potential Electricity Consumption of the Electric Vehicle Fleet

	2014 Data
Vehicle-miles traveled (millions)	3,025,656
divided by: EV Miles/kWh	2.6
divided by: Charge Discharge Efficiency	90%
Potential Electricity Consumption (GWh)	1,276,715
Total US Electricity Consumption - 2014 (GWh)	3,764,700
Potential Increase in US Electricity Consumption	34%

Source: U.S. Department of Transportation, Nissan, SSR analysis

Absent new generation, this increase in electricity demand would be supplied by those generating units currently operating below their maximum capacity, and would thus disproportionately benefit combined cycle gas and coal fired power plants, whose capacity factor averages only 55%. The 1.3 million GWh increase in electricity demand estimated above is equivalent to ~50% of the combined output of the current U.S. coal and gas fired generating fleets in 2016, enough to raise the capacity factor of these plants above 80%. However, this will be offset, at least in part, by the continued growth of renewable energy over the decades it will take to electrify the U.S. vehicle fleet.

How Much Power Will the EV Fleet Require While Charging?

A fully electrified vehicle fleet would also have a material impact on the level and shape of U.S. power demand over the course of the day and year, likely contributing to a need for additional generation capacity. The success of the power grid in responding to this increase in peak demand, and change in the load profile, will depend to a high degree on the regulatory framework that is rolled out for the integration of electric vehicles.

A critical determinant of the impact of electric vehicles on the level and shape of power demand will be the rate at which they can be charged. This in turn depends on the charging technology used, which is evolving rapidly. Level 1 chargers, the type used to charge from a regular 120 volt outlet, draw ~2 kW. Level 2 chargers, which are currently the type most frequently deployed at commercial and retail sites, draw between 3-10 kW. Level 3 chargers, or "fast chargers," can draw 20-50 kW and may become the norm in the future, although currently their deployment is limited. Tesla's superchargers can draw up to 120 kW and a new 350 kW ultrafast charger was deployed in Europe at the end of 2016, although cars that are able to charge at that rate are not expected to be on the road until 2018. The broad range of capacity of the different chargers implies that the same electric vehicle could draw up to 5x as much power at a Level 2 charger as at a level 1; 25x as much power at a Level 3; 60x as much power at a supercharger; and 175x at an ultra-fast charger.

As the capacity of the charger increases, the time required to charge an electric vehicle's battery falls commensurately. America's 260 million vehicles travel ~3 trillion miles annually, or an average of 32 miles per day. If the average energy efficiency of a fully electrified U.S. vehicle fleet were 2.6 miles per kWh, as estimated above, then on average electric vehicles would expend 12.25 kWh per day and require 13.6 kWh of charging at night, allowing for a 10% loss of electricity across the charge/discharge cycle. At a Level 1 charge capable of drawing 2 kW from the grid, the average vehicle would thus take 6.8 hours to recharge; at a Level

2 charger capable of drawing 5 kW from the grid, this would fall to 2.7 hours; at a Level 3 charger drawing 50 kW, only a quarter of an hour would be required; and at a Supercharger capable of drawing 120 kW, only seven minutes. **Exhibit 4** shows the calculations behind these estimates of the average charging times of electric vehicles, and provides more granular estimates of the charging times of light duty and heavy duty electric vehicles, respectively.

Although likely an infrequent occurrence for most passenger vehicles, to charge a fully depleted battery would take significantly longer. We estimate the average vehicle with a 300 mile range and efficiency of 2.6 miles/kWh would have a 115 kWh battery. As the average vehicle travels only 32 miles per day, using just 12.25 kWh of electricity from its 115 kWh battery, EV batteries should retain on average ~89% of their charge at the end of any given day. A road trip of 300 million, however, would fully deplete a 115 kWh battery; allowing for 10% charging losses, the battery would require 128 kWh to recharge. Charging a fully depleted 115 kWh battery would thus take 64 hours with a Level 1 charger, 25.6 hours with a Level 2 charger, 2.6 hours with a Level 3 charger, 1.1 hours with a supercharger and only 22 minutes with an ultra-fast charger.

Hence the commercial incentive for EV manufacturers to roll out higher capacity charging technology. As this rollout occurs, the charging demand of EVs will rise commensurately – posing, as we shall see, a significant threat to the grid.

Exhibit 4: Average Daily Charging Requirement and Duration of Charge for U.S. EVs

	Light Duty Vehicles		Heavy Duty Vehicles		Entire Vehicle Fleet	
Total vehicle miles per year	2,072,071	million miles	953,585	million miles	3,025,656	million miles
Total vehicles	187.6	vehicles	72.8	vehicles	260.4	vehicles
Average daily mileage per vehicle	30.3	miles	35.9	miles	31.8	miles
Average miles per gallon	3.5	miles per kWh	1.0	miles per kWh	2.6	miles per kWh
Electrcity expended	8.6	kWh	37.7	kWh	12.2	kWh
Charge required	9.6	kWh	41.9	kWh	13.6	kWh
Duration of Charge						
Level 1 Charger - 2 kW	4.8	hours	21.0	hours	6.8	hours
Level 2 Charger - 5 kW	1.9	hours	8.4	hours	2.7	hours
Level 3 Charger - 50 kW	0.2	hours	0.8	hours	0.3	hours
Supercharger - 120 kW	0.1	hours	0.3	hours	0.1	hours

Source: Department of Transportation, SSR analysis

Important for the discussion that follows is the very large amount of electricity required to recharge the batteries of heavy duty vehicles such as trucks and buses. Covering an average of 36 miles per day with an energy efficiency of only 1 mile per kWh, heavy duty vehicles would consume 36 kWh on the average day and, allowing for 10% charging losses, would require ~42 kWh to recharge. Even at a Level 2 charger, capable of delivering 5 kW of power, this would take 8 hours (**Exhibit 4**). We believe it reasonable to assume, therefore, that the owners of electric trucks and buses will deploy Level 3 chargers, at a minimum, whose 50 kW of capacity can reduce average charging times below one hour.[2]

[2] Six axle tractor trailers would take much longer. Tractor trailers would likely get an average of less than 1 mile/kWh and would probably want an 800 mile range; regulations allow a driver 11 hours at the wheel after a 10 hour break. The size of a tractor trailer battery would thus exceed 800 kWh and would likely require ~1,000 kWh to recharge. This would take about 8 hours even with a 120 kW supercharger and 3 hours with an ultra-fast charger, suggesting that truck stops along interstate highways would generally have superchargers and ultra-fast chargers.

Similarly, if electric drive vehicles are to replace those with internal combustion engines in the light duty fleet, the time required to charge these vehicles will have to fall; the ~5 hours required to charge a passenger car after average daily use using a Level 1 charger is likely to be an impediment to the widespread adoption of EVs. Looking ahead to a date when the U.S. vehicle fleet has been fully electrified, therefore, we believe it reasonable to assume that Level 2 chargers capacity will become the norm for residential charging, reducing the charging time for a passenger vehicle to less than two hours. Even faster Level 3 fast chargers may be encouraged or subsidized by utilities in order to reduce charging time and allow the utilities to stagger customer charging times during the night.

In **Exhibits 5** through **7**, we illustrate the risk that the charging of an entirely electrified U.S. vehicle fleet poses for the U.S. power grid. We examine the implications of two scenarios, one in which the entire fleet is charged in the evening hours, with cars plugged in at drivers' homes and trucks charging at their depots or garages; and a second where a fraction of the fleet charges during the day, at workplaces and retail centers for light duty vehicles and at depots, garages and charging stations for trucks and buses. Both charging scenarios could potentially overwhelm the generation capacity of the grid. In the first case, drivers returning home after work would tend to arrive at their homes and plug in their cars at precisely the time when power demand is already at its highest: the early evening, when electricity demand for cooking, lighting, television, subways and railroads tend to reach a near simultaneous peak. In the second case, daytime charging, the risk is that charging demand in the afternoon hours could add to the capacity required to serve load on hot summer afternoons, when power demand often reaches its highest level of the year.

Exhibit 5 illustrates the first scenario, evening charging. As discussed above, we assume that light duty electric vehicles will be hooked up to Level 2 chargers capable of drawing 5 kW from the grid and that heavy duty vehicles (trucks and buses) will plug in to Level 3 chargers capable of drawing 50 kW. Under these assumptions, the simultaneous charging of all the nation's light duty vehicles would require ~1,240 GW of power, while the charging of the heavy duty vehicle fleet at the would add ~600 GW of demand. In theory, the simultaneous charging of a fully electrified U.S. vehicle fleet would thus require 1,840 GW of capacity. In 2016, peak demand on the U.S. power grid reached ~740 GW; adding the capacity required to charge the electric vehicle fleet could increase this to 2,580 GW. If a 15% reserve margin[3] is to maintained, this implies the need for 2,970 GW of dispatchable generation capacity.[4] Currently, the U.S. generation fleet includes ~950 GW of dispatchable resources, implying a need for an additional 2,000 GW of capacity, or a tripling of the existing fleet.

[3] Reserve margin is the excess of dispatchable generation capacity over peak demand, expressed as a percentage of peak demand. Regional transmission organizations generally seek to maintain reserve margins of 15% or higher to ensure that the failure of a large power plant or critical transmission interconnection will not cause an interruption in power supply.
4 Intermittent renewable resources, such as wind and solar, may not be available when needed to meet peak demand. We have therefore excluded these from the calculation of dispatchable capacity, including only thermal generating resources (nuclear, coal, gas, oil, geothermal and biomass) and reservoir hydro.

Exhibit 5: Estimated Generation Capacity Required to Supply the Simultaneous Charging Load of a Fully Electrified U.S. Vehicle Fleet

	Millions of Vehicles	Percentage Charging	Assumed Charger Capacity (kW)	Simultaneous Charging Demand (GW)	As % of Dispatchable US Generation Capacity
Light duty vehicles	248	100%	5	1,240	130%
Trucks and buses	12	100%	50	600	63%
Total	260			1,840	193%

Source: Energy Information Administration, Department of Transportation, SSR estimates and analysis

The social cost of such an outcome would be enormous. If the new generation capacity comprised simple cycle gas turbines, costing ~$680,000 per MW, the total cost of the 2,000 GW (2,000,000 MW) expansion can be estimated at $1.4 trillion. To prevent this outcome, state legislators and regulators will be required to frame laws and regulations that incent or limit the charging of electric vehicles to those hours when demand is otherwise low and existing generation capacity is underutilized. Even during these hours, it will be necessary, if cost is to be minimized, to stagger the charging of electric vehicles.

Exhibit 6 illustrates how staggering the charging of vehicles can materially reduce the additional capacity required to charge the electric vehicle fleet. If, in addition, the timing of EV charging can be shifted to coincide with the hours of lowest demand, the additional capacity required to accommodate their charging demand can be reduced a manageable level.

Exhibit 6: Estimated Generation Capacity Required to Supply the Charging Load of a Fully Electrified U.S. Vehicle Fleet If Staggered Over Six Hours

	Millions of Vehicles	Percentage Charging	Assumed Charger Capacity (kW)	Simultaneous Charging Demand (GW)	Hours Required to Charge	Demand if Staggered Over 6 Hours (GW)	As % of Dispatchable US Generation Capacity
Light duty vehicles	248	100%	5	1,240	1.9	413	43%
Trucks and buses	12	100%	50	600	0.8	100	10%
Total	260			1,840		513	54%

Aggregate demand on the U.S. power grid generally reaches its lowest level – equivalent to ~45% to 50% of installed capacity -- between the hours of midnight and 6 AM. As we calculated in **Exhibit 4**, the average time required to recharge the battery of light duty vehicle fleet using a 5 kW charger can be estimated at slightly under two hours; thus, if the charging of the light duty fleet were staggered in two hour increments across the six hours from midnight to 6:00 AM, the maximum charging demand of the fleet would be cut by two thirds from 1,240 GW to 413 GW (**Exhibit 6**). The average charging time required by trucks and buses, using 50 kW chargers, can be estimated at under an hour; if the charging of the heavy duty fleet were also staggered, so that only a sixth of the fleet was charging during each hour from midnight to 6 AM, the charging demand of the heavy duty fleet could be reduced from 600 GW to 100 GW. The maximum charging demand of the electric vehicle fleet as a whole would thus fall from 1,840 to 513 GW, or from ~195% to ~55% of U.S. dispatchable generation capacity.

Assuming system load between midnight and 6 AM otherwise does not exceed 50% of installed capacity, only a 5% increase in dispatchable generation capacity would be required to accommodate the staggered charging of the EV fleet. To maintain a reserve margin of 15%, however, would require the addition of ~190 GW of capacity, or 20% of current installed dispatchable capacity. While substantial, if phased in over three decades this would translate to an annual increase in U.S. dispatchable capacity of just 0.6% per year. Given the otherwise slow growth of peak power demand (peak power demand in the United States has increased at a compound annual rate of just 0.6% over the last decade) the task should be highly manageable. Over the ten years from 1999-2009, the capacity of the U.S. power generating fleet grew at a compound annual rate of 2.7%, increasing the installed capacity of the fleet by over 30%.

We conclude this section by considering the implications of daytime charging of electric vehicles. Daytime charging will be a necessity for vehicles that operates continuously at night or which are engaged in long distance travel; in addition, some portion of fleet may choose to charge during the day, taking advantage of chargers installed at work places or shopping malls. In **Exhibit 7** we illustrate the implications if 10% of the vehicle fleet charged during the day.

Exhibit 7: Potential Impact on Power Demand of Daytime Charging of Electric Vehicles

	Millions of Vehicles	Percentage Charging	Assumed Charger Capacity (kW)	Simultaneous Charging Demand (GW)	Hours Required to Charge	Charging Demand if Staggered Over 8 Hours (GW)	As % of Dispatchable US Generation Capacity
Light duty vehicles	248	10%	5	124	1.9	31	3%
Trucks and buses	12	10%	50	60	0.8	8	1%
Total	260			184		39	4%

Source: Energy Information Administration, Department of Transportation, SSR estimates and analysis

As **Exhibit 7** illustrates, the simultaneous charging of 10% of the entire electric vehicle fleet would increase power demand by ~184 GW. Uncontrolled, this charging could take place during afternoon hours, potentially straining the capacity of the grid on hot summer days when system load often reaches its annual peak. In 2016, peak demand on the U.S. power grid reached ~740 GW; adding the capacity required to charge 10% of the electric vehicle fleet could increase this to 924 GW. If a 15% reserve margin is to be maintained, this implies the need for ~1,060 GW of dispatchable generation capacity. Currently, the U.S. generation fleet includes ~950 GW of dispatchable resources, implying a need for an additional 110 GW of capacity, or an increase of ~12% in the existing fleet.

If we assume, however, that the daytime charging of electric vehicles were staggered across the eight hours of the working day, maximum daytime charging demand could be reduced to less than 40 GW. Added to 2016 peak demand of 740 GW, this could increase demand to 780 GW. The existing dispatchable generating fleet of 950 GW could cover this increased peak load with 170 GW to spare, for a reserve margin of 22%. In this case, the staggering of electric vehicle charging eliminates the need for new generation capacity.

Finally, we note that even without staggering, system stability could be preserved if the capacity of charging stations could be remotely curtailed whenever system load during peak demand hours threatened to exceed available capacity.

Our view is that the smooth integration of the electric vehicle fleet onto the grid will require centralized management of the times at which millions of electric vehicles are individually charged at night. It may also be necessary, under emergency conditions, to exercise centralized management over the charging of vehicles at work places and retail spaces during the day, for example by curtailing the supply of power to chargers when power demand approaches the available capacity on the grid. Alternatively, batteries may be required at the larger charging sites in order to absorb spikes in charging demand and mitigate their impact on grid stability.

In the absence of such centralized management, society will face the risk that the simultaneous charging of electric vehicles will either overload the grid or the pocket books of electricity consumers, who will be required to pay for a massive and unnecessary expansion of generation capacity. We will discuss the legislative and regulatory initiatives required to achieve smooth integration in the section that follows.

The Physical and Regulatory Framework to Integrate Electric Vehicles

The smooth integration of the electric vehicle fleet onto the grid will require careful planning, leading to the timely implementation of power system upgrades and, equally important, of a well designed legislative and regulatory framework for the control of charging demand.

In the examples above, we have focused on the capacity additions required to accommodate the charging demand of electric vehicles. Even more important, particularly in the short to medium term when the share of EVs in the vehicle fleet is lower, will be the hardening of distribution circuits to deliver the power required for charging at all hours of the day. Because the nighttime charging of electric vehicles would sustain the evening peak in residential demand well into the morning, a significant investment in upgrading residential circuits and particularly transformer capacity in residential neighborhoods may be required. Even more robust grid hardening would be required to deliver the massive amounts of power needed for fast charging stations or to charge heavy duty vehicles at their garages or depots.

The charging of electric vehicles will change not only the level of power demand but also the times and the locations at which electricity is consumed. In addition to planning capacity additions and the hardening of the distribution grid, system operators will also need to analyze how charging demand will affect the dispatch of existing generating plants and the use of transmission and distribution circuits over time. Increased night time demand will be welcome in markets where abundant nocturnal wind energy has forced power prices to zero or below, while day time charging could absorb excess solar generation during the middle hours of the day. Increased night time demand should also be reflected in higher capacity factors for mid-merit conventional power plants, such as combined cycle gas turbine generators. If night time charging were to sustain a higher minimum level of demand across the 24 hours of the day, some of these units could be dispatched continuously, operating as base load plants. By reducing the portion of the system's mid merit capacity that would be required to ramp its power output up in the morning and down in the evening, the operation and maintenance expense associated with cycling these units would be reduced and their useful lives extended.

Electric vehicle charging could affect the pattern of dispatch of the generation fleet over the course of the year as well as over the course of the day. If electric vehicle charging demand is relatively flat year round, adding a layer of demand that is continuous across all the months of the year, the common industry practice of bringing major power stations down for maintenance during the low demand "shoulder months" of the spring and fall may have to modified, with scheduled maintenance spread out over more months of the year. The powering down of coal fired power plants for maintenance, and nuclear power plants for refueling, will have to be offset not by lower seasonal power demand but by increased output from other components of the generating fleet. This would stabilize the capacity factors of gas fired generators, which historically have been characterized by marked seasonal swings.

This raises the issue of the knock-on effect of vehicle charging on the gas transmission, storage and delivery system. In regions where inadequate pipeline infrastructure has forced gas deliveries to power plants to be curtailed during cold winter weather, in order to ensure adequate deliveries to residential consumers for heating, the increase in early morning power demand caused by the charging of electric vehicles will significantly increase the stress on the system. If charging demand sustains the output of the gas fired fleet at higher levels year round, the pattern of injecting gas into storage during low demand shoulder months will change, with more gas being delivered directly to power plants. With the dispatch of gas fired power plants likely to rise both on daily and seasonal basis, natural gas production and transmission volumes will have to rise commensurately.

However, if charging demand can be shifted to match supply, electric vehicles could allow for greater use of excess output from wind and solar, improving the economics of renewables on the grid and encouraging utilities to deploy more of these resources. This would reduce the impact of electric vehicles on other forms of generation and natural gas demand. Many states would also favor this because it would increase the health and environmental benefits of the switch to electric vehicles.

The possibly widespread impact of EV charging across the power and natural gas delivery systems, and its potential to push power and gas demand above system limits, highlights the critical importance of a legislative and regulatory framework that allows centralized management of charging demand. As noted above, in the absence of such centralized control, society will face the risk that the simultaneous charging of electric vehicles will either overload the grid or the pocket books of electricity consumers, who will be required to pay for a massive and unnecessary expansion of generation capacity.

As illustrated in **Exhibit 5**, uncontrolled charging of electric vehicles during the evening presents the greatest threat to grid stability, adding demand equivalent to 193% of dispatchable generation capacity at a time when load is already near its peak as electricity demand rises simultaneously for commuting, cooking, lighting and TV. Rendering nocturnal charging demand manageable requiring the staggering of vehicle charging. Utilities will need to be able to signal optimal charging times to the vehicle's owner, or directly control the chargers remotely, powering them up in shifts so that vehicle charging is staggered through the night.

Day time charging at public charging stations (those at work places, for example, or shopping centers) could similarly be subject to centralized management. When available generation capacity was abundant relative to demand, all public chargers might be supplied with electricity. However, when the demand for power on the grid approached the limit of available generation capacity, the supply of electricity to chargers designated as interruptible could be stopped. To incent vehicle owners to charge when demand was low, the price of electricity at chargers could vary through the day, tracking the wholesale price of electricity as this rose and fell in response to the supply/demand balance on the grid. Prices might also vary by location, to discourage charging in locations where circuits were becoming overloaded. Again, if necessary to alleviate stress on local circuits, the supply of power to interruptible chargers could be halted.

Such a system would require a sophisticated combination of smart grid technologies, including sensors, monitors, and communication and control equipment. Batteries might be deployed at charging stations to serve charging demand when the supply/demand balance on the grid was tight. Utilities would require new software and computing capability to determine when and where prices should be re-set, batteries discharged or chargers disconnected and to predict patterns of demand and supply to optimize customer behavior and maintenance costs. Similarly, vehicles would need to have the ability to communicate with the grid to be able to respond to price signals and utility directions autonomously and to locate available chargers. Vehicle owners would also need a smart phone app that allowed them to monitor their vehicles' state of charge and adjust parameters like price points and flexibility on timing of charge over the course of the day.

A fascinating question is how the network of vehicle chargers could also be used to draw power from vehicle batteries for the grid. A network of chargers on the scale illustrated in **Exhibit 6** would be capable of supplying 500 GW of power, or the equivalent of 50% of dispatchable generation capacity in the United States. In theory, this network could also be used to pull a similar amount of power from vehicle batteries and supply it to the grid. By comparison, the capacity of the entire U.S. peaking fleet is only 175 GW.

In certain respects, vehicle batteries are well suited to provide reserve capacity to the grid. While vehicle batteries are sized to supply the energy required for a long road trip (200 to 300 miles), the average distance traveled by a light duty vehicle in the United States is only 30 miles a day. The implication is that the average daily discharge of vehicle batteries is only 10% to 15% of their capacity. On an average day, therefore, the remaining 85% to 90% of the battery's capacity might be offered as storage capacity to the grid.

Vehicle owners prepared to do so might be paid an hourly capacity charge to hook their vehicles to two way chargers subject to the utility's control. To avoid being forced to walk home, vehicle owners would be allowed to stipulate the maximum amount of energy that the utility could draw from their battery – even 10-20% of capacity would be a significant resource for the grid. The utility would pay for any electricity it drew from the battery at the then prevailing wholesale price for electricity, potentially adjusted for local conditions. The vehicle's owner would have to weigh whether these payments were sufficient to offset the cycling of his battery and the consequent reduction in its useful life. Vehicle owners might be allowed, therefore, to offer capacity from their batteries at prices of their choosing; the utility would accept these offers in ascending order of price until its need for reserve capacity was met. These opportunities might be particularly attractive for the owner of fleets of heavy duty vehicles, whose large batteries and, more importantly, high capacity chargers would render them particularly valuable as sources of power for the grid. Operating at a much larger scale, fleet owners would be better positioned to monitor power market conditions and modify the utilization of their vehicles as necessary to capitalize on periods of high demand and generation scarcity. For the utility, the ability to draw on customer batteries would dramatically reduce the amount of new generating capacity needed for a fully electrified fleet and could allow nearly all of the growth in energy demand to be met with renewables.

In the long run, we could see the utility pricing model migrating to dynamic, localized real-time pricing. This would be a structure whereby rates for electric vehicle charging and battery storage services, and potentially all electricity rates, would vary in short increments, 15 minutes or less, based on supply, demand and equipment conditions on each local circuit. Dynamic local prices would incent changes in vehicle charging and the dispatch of customer-sited storage capacity (potentially including EVs) so as to balance the demand and supply of electricity on the grid, preserving grid stability and reducing the total system cost of electricity. This would require, however, that utilities have the ability to monitor conditions on the grid and to communicate to businesses, homes and vehicles price signals that reflect these conditions. In turn, electricity consumers would require software to respond autonomously based on parameters set by the utility – or, in the case of the discharge of distributed storage, parameters set by the customer.

Such a system would also imply significant cooperation between utilities and electric vehicle manufacturers, particularly with regards to the design of vehicle software to monitor and control the charging. Electric vehicles would have to be able to receive and respond to pricing signals and other parameters communicated by the grid, including curtailments and overrides in emergency situations. EVs will also need the capacity to respond to centralized management of the times at which they are individually charged at night. Eventually, vehicles may be designed with the capacity to discharge power from their batteries to the grid. If vehicle-to-grid power is to work, it could require modifications to the charging interfaces and batteries of the vehicles.

The Tipping Point: How Many Electric Vehicles Could Be Too Many?

While we believe the grid can accommodate a fully electrified vehicle fleet, changes must be made both to the grid and the regulatory framework for this integration to be successful, and dangerous system failures to be avoided. But by when do these changes need to be made?

In this section, we calculate the tipping point by which utilities and regulators will need to begin to implement changes in order to avoid the risk that uncontrolled charging by electric vehicles could overwhelm the electric grid. As we discussed earlier in this note, we believe the biggest risk is posed during the evening hours starting at 6:00 PM, when most people are returning home from work, fleet vehicles are returning to their depots and when many regions experience their peak demand due to the coincident electricity demand for cooking, lighting, television and mass transit. Utilities and regulators will want to avoid a surge in demand that would exceed their excess generating capacity at that time. Utilities and their regulators generally seek to maintain an excess of dispatchable capacity over peak demand, or reserve margin, of 15%, so that power will remain available despite the failure of a large power plant or transmission interconnection.

Let us use an example of a regional grid with a peak demand of 100,000 MW. In this case, utilities will seek to maintain a reserve margin of 15,000 MW. Charging demand of 15,000 MW or more would thus eliminate the grid's reserve capacity, putting the reliability of the regional power supply a serious risk. This level of charging demand could be reached if 3 million electric vehicles were charging simultaneously using 5 kW chargers (3 million cars x 5 kW = 15 million kW or 15,000 MW). However, not every electric vehicle will be plugging in at 6:00 PM. Some vehicles will not have been driven that day and will not need charging, others will be working late or have arrived home early. On the other hand, it takes on average almost two hours to recharge a light duty vehicle at a 15 kW charger, so EVs plugged in up to two hours apart could be charging simultaneously. Let us assume, therefore, that 75% of EVs might charge simultaneously during the early evening. Under these assumptions, a fleet of 4 million electric vehicles would be sufficient to erode completely the grid's 15,000 MW of margin (4 million EVs x 75% x 5 kW = 15 million kW or 15,000 MW).

As a rule of thumb, therefore, we see a tipping point for regulators and utilities to act when the number of electric vehicles, measured in units, approaches 40x a region's peak load, measured in MW. For example, on a 100,000 MW grid, our rule of thumb of 100,000 x 40 suggests that 4 million vehicles would be the tipping point.

For California, with a peak load of 46,000 MW, this implies a tipping point at 1.84 million electric vehicles, or just 6% of the current total vehicle fleet. For the entire US, with a peak demand of 741,000 MW in 2016, the tipping point would be 29.6 million electric vehicles, or about 11% of the current total vehicle fleet.

Where and When Will the Impact of EVs Fist Be Felt?

While the fleet of battery electric vehicles[5] (BEVs) in the United States has been expanding rapidly, growing at a compound annual rate of 95% over the last five years (2011-2016), BEVs remain a tiny fraction of the vehicle fleet, comprising only one tenth of one percent of all U.S vehicles (**Exhibit 8**). The battery electric vehicle fleet, moreover, is highly concentrated regionally, with over half of all the nation's electric vehicles located in California (**Exhibit 9**). In California, BEVs now account for nearly one half of one percent of vehicles in the state, a penetration rate approaching five times the national average, suggesting that California's utilities will be the first to face the issues presented by the integration of BEVs onto the power grid.

[5] Exclusively electric drive vehicles; excludes hybrid electric/internal combustion engine vehicles.

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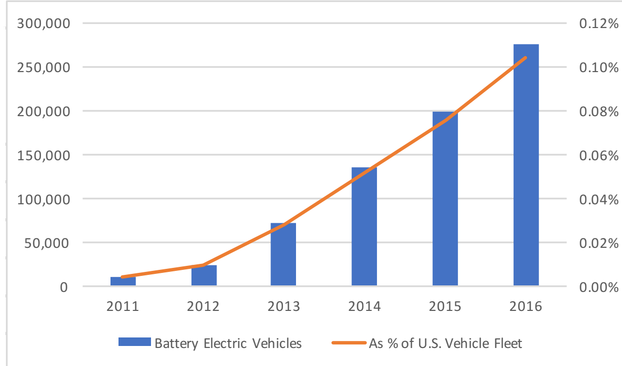
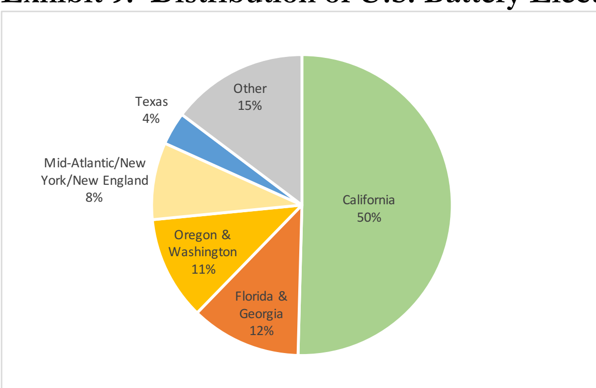
Exhibit 8: U.S. Battery Electric Vehicles and Their Share of the U.S. Vehicle Fleet (1)

	Total BEVs	% of U.S. Vehicle Fleet	Annual % Change
2016	274,789	0.10%	39%
2015	198,088	0.08%	47%
2014	134,748	0.05%	88%
2013	71,707	0.03%	197%
2012	24,107	0.01%	146%
2011	9,782	0.00%	



1. Excludes hybrids
Source: U.S. Department of Transportation, SSR analysis

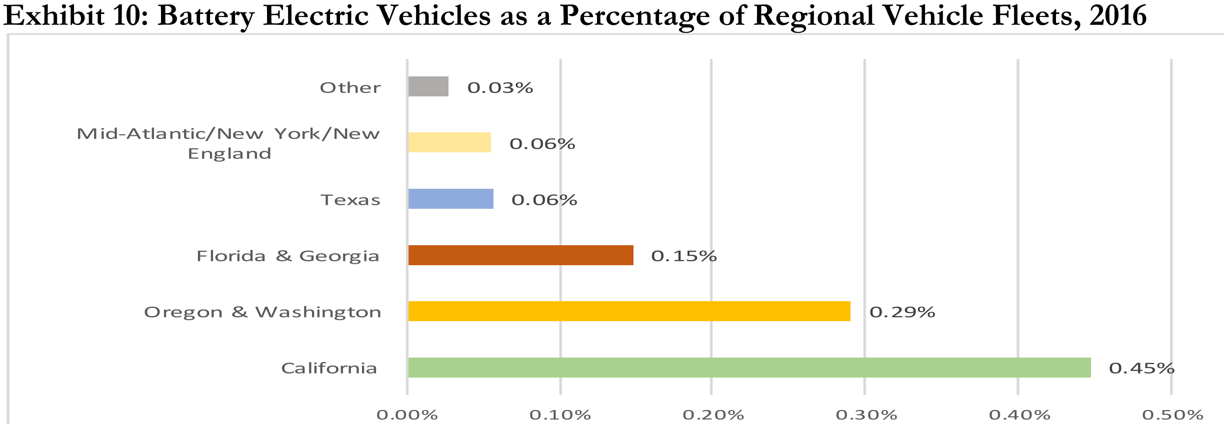
Exhibit 9: Distribution of U.S. Battery Electric Vehicles by Regional Market



	BEVs	% of All U.S.
California	138,531	50%
Florida & Georgia	32,614	12%
Oregon & Washington	30,682	11%
Mid-Atlantic/New York/New England	22,774	8%
Texas	9,724	4%
Other	40,464	15%
Total	274,789	100%

1. Excludes hybrids
Source: U.S. Department of Transportation, SSR analysis

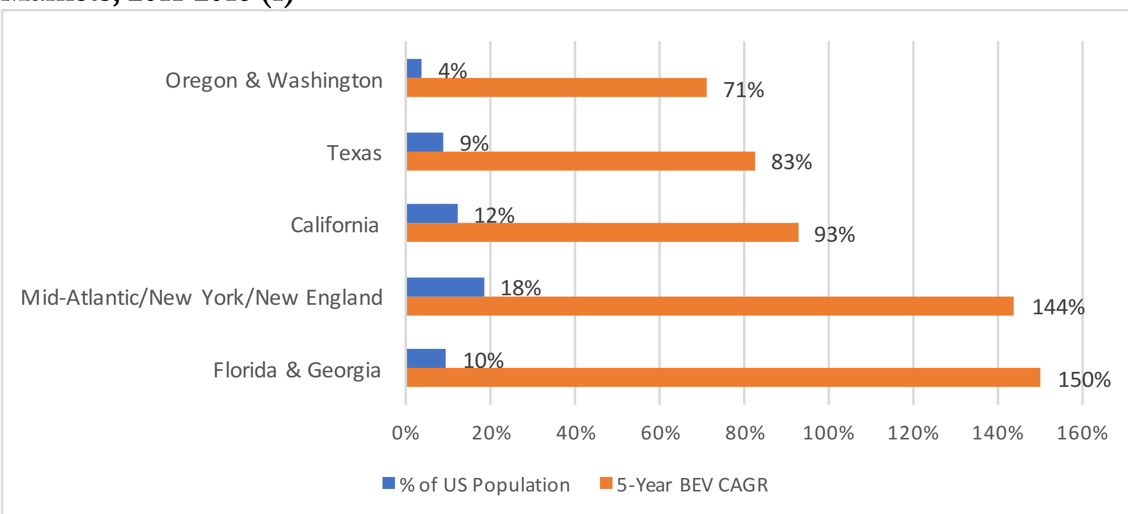
Exhibit 10: Battery Electric Vehicles as a Percentage of Regional Vehicle Fleets, 2016



1. Excludes hybrids
Source: U.S. Department of Transportation, SSR analysis

Substantial fleets of battery electric vehicles exist outside of California (**Exhibit 9**), and some of these fleets are currently growing at faster rates (**Exhibit 11**). Outside of California, with its ~140,000 BEVs, large fleets of battery electric vehicles are found in other coastal regions, including the southeast (Georgia and Florida together have ~33,000 BEVs), the Pacific Northwest (Oregon and Washington are home to 31,000 BEVs) and the metropolitan region stretching from Washington to Boston (the Mid-Atlantic states, New York and New England are together home to 23,000 BEVs). Over the last five years, the most rapid growth in BEV fleets has been realized in Florida and Georgia (compound annual growth of 150%, partly due to particularly generous tax subsidies in the latter state that expired in 2015) and the Washington to Boston region (compound annual growth of 144%). The California fleet of BEVs, by contrast, expanded at a 93% compound annual rate over the last five years (**Exhibit 12**). Over time, therefore, we are likely to see a more regionally diverse U.S. fleet of BEVs, with the East Coast representing a rising percentage of the national total.

Exhibit 11: Five-Year CAGR in the Fleets of Battery Electric Vehicles in Five Principal U.S. Markets, 2011-2016 (1)



1. Excludes hybrids
Source: U.S. Department of Transportation, SSR analysis

Exhibit 12: Battery Electric Vehicle Fleets, Penetration Rates, and Five-Year Compound Annual Growth Rates in Five Principal U.S. Markets, 2011-2016 (1)

	BEVs	As % of Vehicle Fleet	5-Year CAGR of BEV Fleet	Population (Millions)	As % of U.S. Population
California	138,531	0.447%	93%	39	12%
Florida & Georgia	32,614	0.148%	150%	31	10%
Oregon & Washington	30,682	0.290%	71%	11	4%
Mid-Atlantic/New York/New England	22,774	0.055%	144%	60	18%
Texas	9,724	0.057%	83%	28	9%
All Five Regions	234,325	0.197%	96%	169	52%

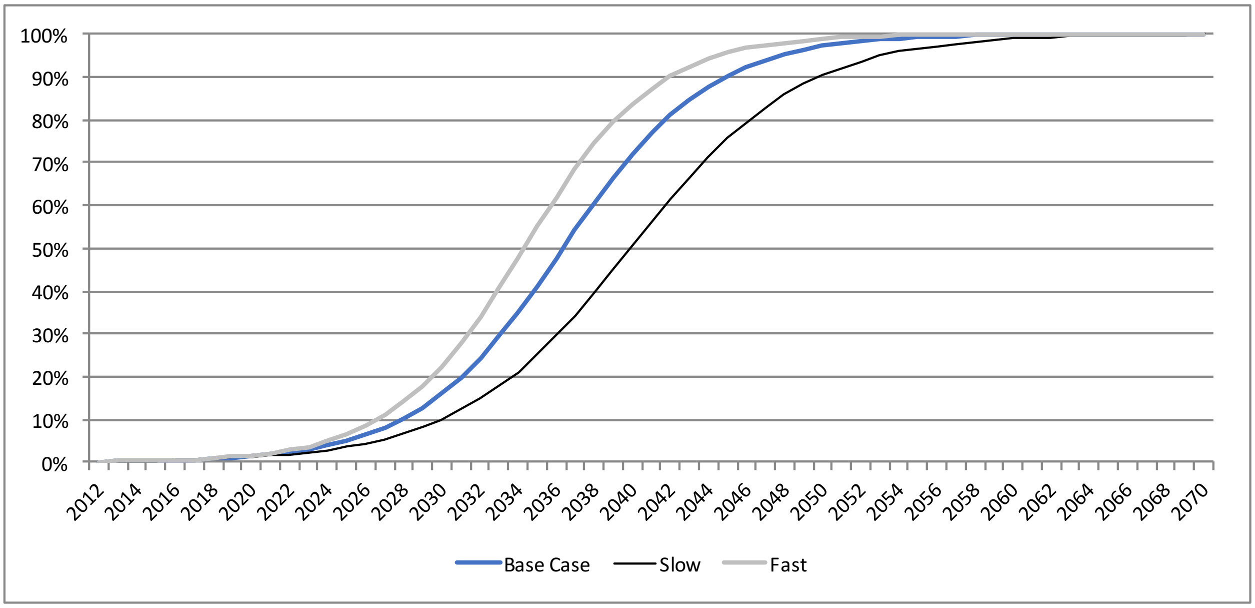
1. Excludes hybrids
Source: U.S. Department of Transportation, SSR analysis

We expect, therefore, that the first distribution utilities to benefit from the investment opportunities created by electric vehicles will be Edison International (EIX) and PG&E Corp. (PCG) in California, where state policy is to put 4.2 million EVs on the road by 2030, equivalent to one eighth of the current vehicle fleet and well above the 1.8 million vehicles we identify as a potential tipping point for the California grid. The region with the second highest EV penetration is the Pacific Northwest, partly reflecting Oregon's zero emissions vehicle (ZEV) standard. Portland General Electric (POR) and Avista (AVA) stand to benefit from growth in the Northwestern EV fleet. The EV fleet in the Northeast and Mid-Atlantic, while small currently, has grown over the last five years at an average annual rate of 144% in response to ZEV standards put in place by Maryland, New York, Massachusetts, Connecticut, Rhode Island and Vermont. The growth of the EV fleet in the heavily populated Washington to Boston corridor will benefit Consolidated Edison (ED), Eversource Energy (ES), and Avangrid (AGR), as well as the distribution utility subsidiaries of Exelon (EXC) and Public Service Enterprise Group (PEG).

The very low penetration of BEVs in the national vehicle fleet suggests that there is ample time for most electric utilities, their regulators and state legislators to plan the physical and legal infrastructure for their rollout. An analysis of typical technology adoption curves, however, suggests that utilities and regulators must seize the reins now: failure to plan over the next ten years could force the power industry to adapt in a much shorter time frame to levels of penetration that would threaten grid stability.

To estimate how quickly BEVs may reach benchmark levels of penetration, and thus the amount of time planners have to prepare, we have constructed hypothetical technology adoption curves showing the penetration of BEVs in the California vehicle fleet over time. Our base case (shown in blue in **Exhibit 13** below) assumes that California meets the targets set for the state's BEV fleet set in the California Air Resources Board's *2017 Climate Change Scoping Plan Update*, which seeks to put 4.2 million zero emission vehicles on the road by 2030. The CARB plan was developed to implement the requirements of (i) the California Global Warming Solutions Act of 2006 which seeks to reduce California's greenhouse gas emissions to 1990 levels by 2020, and (ii) Governor Brown's Executive Order B-30-15 which targets a further reduction in greenhouse gas emissions to levels 40 percent below 1990 levels by 2030.

Exhibit 13: Alternative Technology Adoption Curves Showing the Penetration of Electric Vehicles in the California Vehicle Fleet



	Year in Which EV Penetration of Vehicle Fleet Reaches:			CAGR in EV Sales Until Penetration Reaches:		
	25%	**50%**	**90%**	**25%**	**50%**	**90%**
Base Case	2033	2037	2045	27%	25%	20%
Fast Case	2031	2035	2042	31%	28%	22%
Slow Case	2035	2040	2050	23%	21%	11%

Source: SSR estimates and analysis

To put the implications of this growth trajectory into perspective, consider the impact on the grid of CARB's goal of putting 4.2 million BEVs on the road by 2030. As discussed above, absent mandatory staggering of vehicle charging, the risk is high that a large percentage of the BEV fleet would be plugged in to charge in the early evening when their owners return home from work – at the same time that California's aggregate power demand tends to peak, due to coincident electricity demand for cooking, lighting, television and mass transit. Indeed, we estimate that, once California's BEV fleet reaches only 2.0 million vehicles, or just over 6% of the current total vehicle fleet in state, there is material risk that uncontrolled charging by electric vehicles during peak demand hours could overwhelm the grid. Assuming these 2.0 million vehicles are light duty BEVs using 5 kW Level 2 chargers, the simultaneous charging of only 75% of this fleet would create 7.5 million kW or 7.5 GW of demand. The California ISO currently has only 54.5 GW of available summer capacity to serve 47.2 GW of peak summer demand, providing a reserve margin of 7.3 GW of capacity – suggesting that the state's reserve margin could be completed eroded by the uncontrolled charging demand of a 2.0 million vehicle fleet.

Serving 7.5 GW of charging demand on top of California's 47.2 GW peak load, while preserving CAISO's 15% target reserve margin, would require 63 GW of dispatchable capacity, implying a need for 8.5 GW of additional capacity. At an assumed cost of $680/kW of capacity installed (the approximate cost of new simple cycle gas turbine peaker), this would require an investment of ~$5.7 billion.

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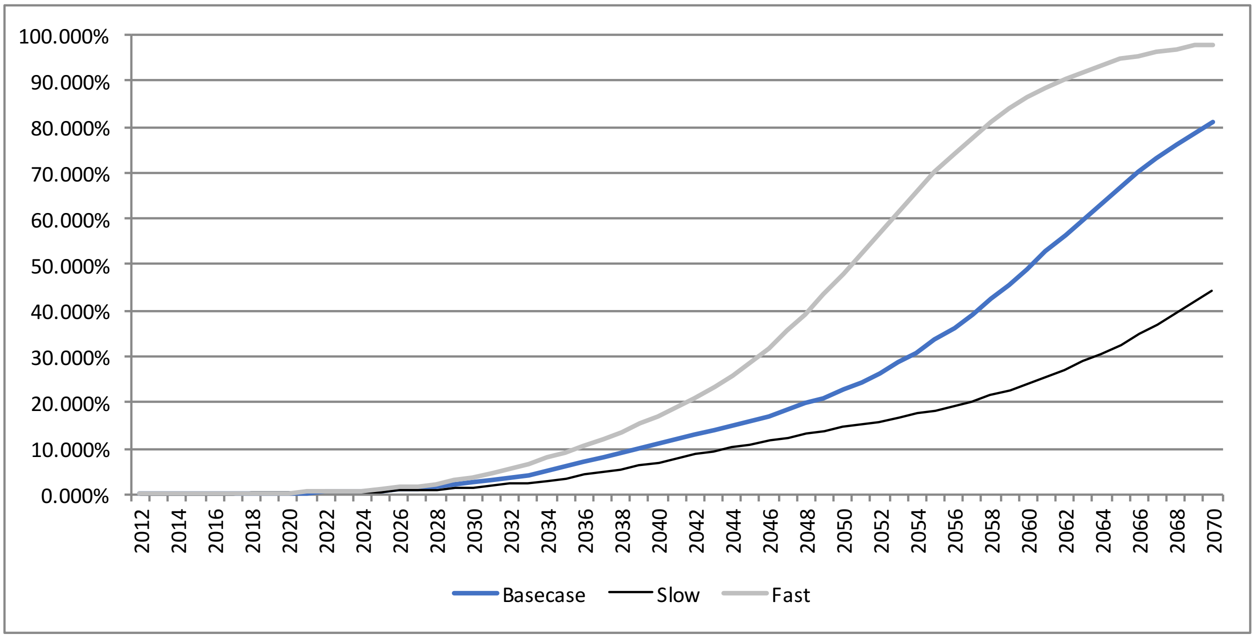
More likely, California will develop a legal and regulatory framework for the charging of these vehicles that would mitigate the impact, such as subjecting charging to centralized management and staggering it over the six hours from 12 AM to 6 AM when power demand on the grid is lowest. The average charge required by a light duty vehicle can be supplied in two hours by a 5 kW charger, permitting three charging shifts over this six hour period. On these assumptions, the charging of California's target 2030 BEV fleet of 4.2 million vehicles could be limited to 7 GW (4.2 million EVs x 5 kW/3) at a time when power demand on the California grid runs below 30 GW, or some 25 GW less than the system's installed capacity. No additional investment in generation capacity would be required.

While California may be able to limit its investment in new generation over the next decade, it must still confront the need to harden its distribution grid, increasing the capacity of residential circuits and transformers to serve much higher levels of nighttime load. Our hypothetical technology adoption curves highlight the importance of early action to implement these upgrades. These curves suggest that California will achieve 25% BEV penetration somewhere between 2030 and 2035 (2033 in our base case), 13 to 18 years from now; 50% BEV penetration, however, would be achieved only five years later, between 2035 and 2040 (2037 in our base case). This marked acceleration in the growth of the electric vehicle fleet will require a similar acceleration in the pace of investment unless grid hardening is implemented on a front loaded basis.

To provide a comparable perspective on the challenge that will be faced by the U.S. as a whole by the rollout of electric vehicles, we present in **Exhibit 14** hypothetical technology adoption curves modeling the penetration of BEVs in the national automobile fleet. Our base case for the nation incorporates our base case for California, assumes that all other states that currently have targets for zero emissions vehicles achieve them by 2025, and assumes moderate growth of the BEV fleet in the remaining states. These curves suggest that the United States may reach 25% BEV penetration somewhere between 2044 and 2061 (2052 in our base case), 27 to 44 years from now, and that 50% BEV penetration could be achieved seven to twelve years later, between 2051 and 2073 (2061 in our base case). Based on our analysis above, a vehicle fleet of just 44 million vehicles, or ~16% of the current number of vehicles in the US, is a reasonable benchmark of when demand poses a potential risk to overwhelm the electric grid during peak evening hours. Our curves suggest that this benchmark could be reached by 2039 in our fast scenario and in 2045 in our base case.

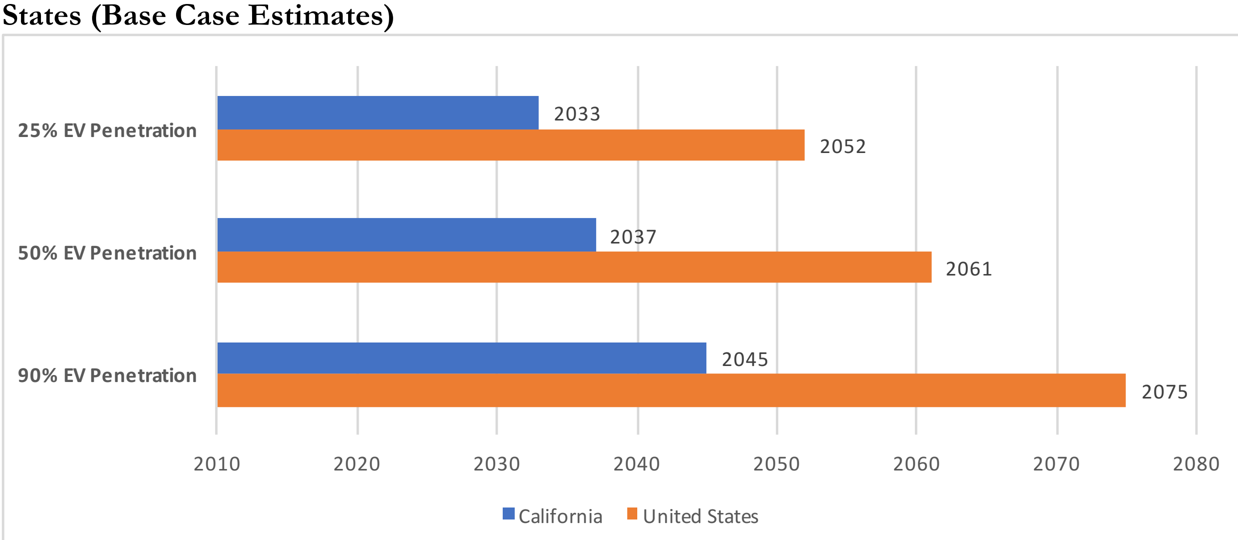
Exhibit 14: Alternative Technology Adoption Curves Showing the Penetration of Electric Vehicles in the U.S. Vehicle Fleet



	Year EV Penetration Reaches:			CAGR in EV Sales to that Year:		
	25%	**50%**	**90%**	**25%**	**50%**	**90%**
Base Case	2052	2061	2075	16%	15%	12%
Fast Case	2044	2051	2062	21%	19%	16%
Slow Case	2061	2073	>2075	13%	11%	NA

Source: SSR estimates and analysis

Exhibit 15: Comparison of Threshold BEV Penetration Dates in California and the United States (Base Case Estimates)



Source: SSR estimates and analysis