

DRIVING INTEGRATION

REGULATORY RESPONSES TO ELECTRIC VEHICLE GROWTH

BY RACHEL GOLD AND CARA GOLDENBERG

AUTHORS & ACKNOWLEDGMENTS

AUTHORS

Rachel Gold and Cara Goldenberg

** Authors listed alphabetically. All authors from Rocky Mountain Institute unless otherwise noted.*

CONTACTS

Rachel Gold, rgold@rmi.org

Virginia Lacy, vlacy@rmi.org

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HELP US TRANSFORM THE POWER SECTOR

e-Lab is working with and analyzing leading power sector transformation initiatives across the country to extract key concepts and ideas and provide decision makers with the research and resources they need to implement effective reforms. We invite regulators, commission staff, and e-Lab members to reach out with suggested future topics. Please contact us at elab@rmi.org.

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EDITORIAL | DESIGN

Editorial Director: Cindie Baker

Editor: Laurie Guevara-Stone

Art Director: Romy Purshouse

Graphic Designer: Marijke Jongbloed

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ABOUT US



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ABOUT e-Lab

e-Lab is a multiyear, multistakeholder forum to address complex electricity system challenges no individual stakeholder can solve alone. e-Lab supports practical innovation across traditional institutional boundaries to overcome barriers to the economic deployment of distributed energy resources in the U.S. electricity sector. e-Lab participants convene and collaborate on solutions and engage in on-the-ground projects that address the biggest challenges facing the sector: new business, pricing, and regulatory models; grid security; customer engagement; and grid integration of low-carbon renewable energy. These changes are critical steps towards a more resilient, affordable, and sustainable electricity system. Please visit <http://www.rmi.org/eLab> for more information.



There has never been a more exciting time to be in the market for an electric vehicle (EV). As the number of plug-in vehicle models available for sale grows to more than 20, coupled with a 70 percent decrease in battery costs and a 40-fold increase in EV charging stations over the past eight years, more customers now have the means to reap the economic, security, and environmental benefits EVs provide.

Yet structural challenges are emerging alongside the rapid, but unpredictable, growth of the EV infrastructure ecosystem. Automakers are continuing to introduce new, competitively priced models in parallel with the build-out of a national charging network. And new mass-market technologies are entering the market that allow EVs to act as demand response resources, help integrate renewable energy onto the grid, and recharge when demand is at its lowest. These developments increasingly require regulators and electric utilities to account for the emergence of a new industry paradigm that challenges traditional policy frameworks.

As greater numbers of EVs hit the roads and charge in garages across the country, it is crucial for regulators and policymakers to collaborate effectively and erect strategies that ensure EVs benefit ratepayers, utilities, and the grid.



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EX

EXECUTIVE SUMMARY



EXECUTIVE SUMMARY

The rapid growth of electric vehicle (EV) charging in the next decade will challenge traditional paradigms of regulation and policy in the electricity sector. The complexity and dynamism of emerging EV industry trends are akin to those of other fast-changing high-tech sectors, with the potential for revolutionary change. Regulators and policymakers alike will have to embrace new approaches that allow for experimentation and adaptation with new technologies, market mechanisms, and institutional arrangements in order for EV growth to benefit rather than impair the grid.

This report explores issues policymakers, especially state utility regulators, face in forming policy and regulation in this dynamic landscape of charging companies, aggregators, municipalities, utilities, and auto manufacturers, among others. Regulators are critical decision makers because of their ability to accelerate or slow EV deployment through policy decisions. They also have an important role to play to enable effective EV integration—both for accommodating new loads from EV charging onto the grid, and for ensuring reliability as new variable resources come online. In this report, we first describe the range of possible benefits that state utility regulators can enable from smart charging beyond simply minimizing impact on peak. We then describe the cases of two leading states—California and Washington—working to unlock the benefits of EVs. Although both California and Washington have addressed EV policy in some way, neither has comprehensively prepared for the arrival of EVs en masse and their potential impacts on the transportation and electricity systems.

Throughout the cases and in the discussion beyond, we pose six questions for regulators to use as analytical tools as they explore options and trade-offs in enabling deployment and integration of EVs. These questions help regulators think through how they will define the need and scope of their role in EV integration, design policies to support that role, and then create adaptive processes to support learning from those changes.

1) How much of a role should utility regulators play in enabling EV integration or deployment?

- Utility regulators should proactively consider policies for enabling the integration of EVs onto the grid where it minimizes costs to ratepayers over time and supports their core mandate to ensure the provision of safe, reliable utility service and infrastructure at reasonable rates.
- Regulators have a role to play in planning for EVs given the challenges that unmanaged charging can create at relatively low penetrations at the distribution level and the opportunities for enabling EV integration as a tool to ensure reliable, lower cost electricity service.

2) What factors will utility regulators have to consider when they evaluate the public interest in the context of EVs?

- State utility regulators must balance competing public interests—such as those of utility ratepayers versus grid-interactive EV car owners—when shaping rate design, EV charger siting and planning, and the utility’s role in EV infrastructure ownership. The choice among these competing interests will be largely based on the principles of equity and cost-effectiveness for the grid as a whole, the limitations of existing law, the appropriate time horizon for considering costs to these groups, and a determination of how much public funding is necessary in addition to private investment to support market transformation.

3) What tools do utility regulators have to encourage effective grid integration and optimal siting?

- To capture the potential value from EV integration, utility regulators should work with utilities to provide customers access to rates and signals that incentivize charging during times of the day when energy demand is low and significant supply is available. They will need to balance grid

system-oriented rates, which would encourage charging during certain times and at locations based on grid needs, and customer-oriented rates, which incentivize charging in convenient locations that influence customer adoption.

- More broadly, utility regulators have an opportunity to proactively ensure EV integration is included in utility planning processes, including the benefit-cost analysis of planned infrastructure upgrades. This is especially true as regulators evaluate the benefits and costs of utility investments in two-way, real-time telemetry and communication systems that can send price signals and will enable optimal EV deployment.

4) Who should own, operate, and maintain charging stations, and what types of incentives should be provided to encourage EV integration and/or deployment through those roles?

- Several different entities could own EV charging stations. To prepare for the potential impacts and benefits of these new EV assets, regulators must determine the extent to which the “regulatory compact” with monopoly utilities should be extended to ownership of EV charging infrastructure.
- It may be appropriate for utilities to own EV infrastructure under certain conditions: if ownership results in net benefits for ratepayers or if there are market segments that a competitive market is unlikely to serve. Where these conditions exist, regulators should design rules and incentives for utilities that encourage investment but do not unfairly promote utility involvement or raise market power concerns. Utility regulators will also have to consider other roles utilities can serve in the operation and maintenance of charging stations.



5) What policy support is necessary to enable aggregation so that EVs can provide demand response and ancillary services?

- To enable EVs to provide grid services, utility regulators need to first determine at what scale a resource can qualify to serve a demand response or ancillary service function, while taking into account the needs of market participants and operators and existing rules and barriers. The choice to define the EV resource as the vehicle, a charging station with an embedded submeter, or the primary facility meter will help determine who has ownership over the resource, how the resource is measured, and how communication is managed.¹ State utility regulators then need to adjust rules in concert with grid operators to ensure that markets or contractual structures are available to support EV aggregation.

6) What are the processes regulators can use to ensure that regulation is adaptive in this dynamic environment?

- Utility regulators should support more frequent, assertive use of scalable demonstration projects to test EV integration approaches and allow solutions to evolve iteratively. Pilots that allow for alternative avenues outside the traditional regulatory framework are necessary to enable experimentation and build adaptive solutions. Pilots should be designed to allow for expansion and scaling and should be evaluated against simple, collaboratively developed metrics to support measurement of success against EV deployment, grid integration, and environmental goals.
- Given the unpredictable nature of EV deployment, utilities should include a wide range of EV growth scenarios in distribution grid planning.

We offer these questions and present options and recommendations as inspiration for regulators to proactively address the opportunities and risks created by this nascent technology.

01

WHY PUBLIC UTILITY REGULATORS NEED TO PREPARE FOR ELECTRIC VEHICLES



2015 Chevrolet Bolt EV Interior
Image courtesy of GM CC BY 3.0 US

WHY PUBLIC UTILITY REGULATORS NEED TO PREPARE FOR ELECTRIC VEHICLES

The development of electric vehicles (EVs) and the growth of the EV market offer new opportunities and potential challenges. During the last decade, the plug-in vehicle market expanded to 20 different models, battery costs decreased by 70 percent, and the number of EV charging stations climbed to more than 16,000.² These evolving trends alleviate consumers' fears of range anxiety and alter perceptions of affordability, making a future of EV-dominated roads a reality much sooner than we might think.

This transformation will be necessary to meet the 1.5°C 2015 Paris climate goal, as the greatest decarbonization challenge the U.S. faces comes from the transportation sector.³ To meet those goals, the electric vehicle market will need to continue to scale,¹ creating a new source of load growth on the distribution system, and generating associated risks and benefits for the electric industry that serves those loads.

As a mobile source of load—demand response on wheels—EVs can support deeper decarbonization of the electricity sector by helping smooth the path for integration of more renewables. These electricity sector benefits require smart charging, in which EVs are charged in beneficial locations and at beneficial times for the system to avoid added stress to the grid. Regardless of where they're charged, EVs create real value for customers through lower operating costs. And with smart charging, EVs also offer the potential for new revenue streams from grid integration services for customers, utilities, and third parties alike.

However, as new sources of electricity demand, EVs can also create costs for the system where their charging is poorly managed. Unmanaged EV loads could increase peak capacity needs, shorten the life of

grid infrastructure components through distribution infrastructure overload, and require greater investment to meet these new peak capacity loads. Further, customer charging behavior is relatively unpredictable, creating the risk of costly or poor investment decisions if companies or customers install charging infrastructure in places where it isn't used. Poor investments may increase electricity costs for all consumers and affect reliability, suggesting the need for regulatory attention to avoid these impacts.

EV DEPLOYMENT AND INTEGRATION

In this paper, we use the term EV deployment to refer to activities that increase the number of EVs on the road. EV deployment policies and incentives encourage EV adoption by making EVs less expensive than internal combustion engine vehicles, or by supporting the build-out of necessary charging infrastructure so customers are more likely to buy EVs. The report uses the term EV integration to refer to activities focused on accommodating new loads from EV charging onto the grid, and for ensuring reliability as new variable resources come online.

In many ways, the story of EVs' interaction with the grid may be analogous to the industry's experience with solar PV. Although solar PV can create net benefits for all ratepayers,⁴ solar deployment and usage may be misaligned with grid system needs in the absence of integrated infrastructure, market design, and incentive policies. In some states, this has led to net metering battles, utility business model challenges, and delayed interconnection queues.ⁱⁱ The risk of misalignment may

ⁱ A wide range of recent studies has found that transportation electrification is going to be an essential strategy to significantly reduce greenhouse gas emissions in the years to come. For example, see Williams J., et al., "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," *Science* 335, 2012, pp. 53–59.

ⁱⁱ For details on these misaligned value streams, see the 2012 RMI paper *Net Energy Metering, Zero Net Energy, and the Distributed Energy Resource Future: Adapting Electric Utility Business Models for the 21st Century*, p. 31.

be starker for EVs because of their unique nature relative to other distributed energy resources (DERs):



Mobile: As mobile assets, individual EVs are more flexible than stationary demand response resources since their on-board battery storage moves around with them. At the same time, this can make it more difficult to guarantee their availability and predict their usage patterns and responsiveness to price signals, although hubs for fleets of vehicles may be more predictably available in the aggregate.



Less Predictable Growth: Mobility as a service and new business model partnerships between utilities and car companies, charging infrastructure companies, and others make the growth pattern and landscape of profit incentives more dynamic.



Cross-Sector Responsibilities: Some of the elements necessary to enable EVs as grid assets—especially infrastructure siting and electricity pricing issues—require coordination across a wider variety of state and local agencies, such as departments of transportation, and across business types, such as car manufacturers, that are rarely or never regulated by public utility commissions.

These unique features of EVs can create benefits and challenges for the grid even at low penetrations. Although EV penetration remains minimal, RMI's recent *Electric Vehicles as Distributed Energy Resources* report finds that a set of accelerating factors will ensure unpredictable but eventual market growth (see *Trends Driving EV Adoption*).⁵ That report also demonstrates that these impacts will materialize at low penetrations because EV loads are likely to be geographically uneven, clustering under particular distribution circuits.

TRENDS DRIVING EV ADOPTION

Car manufacturers will soon be shipping new second-generation EVs, designed to appeal to a much larger market with sub-\$40,000 sticker prices and higher, 200+ mile driving ranges. Specific trends driving EV adoption include:

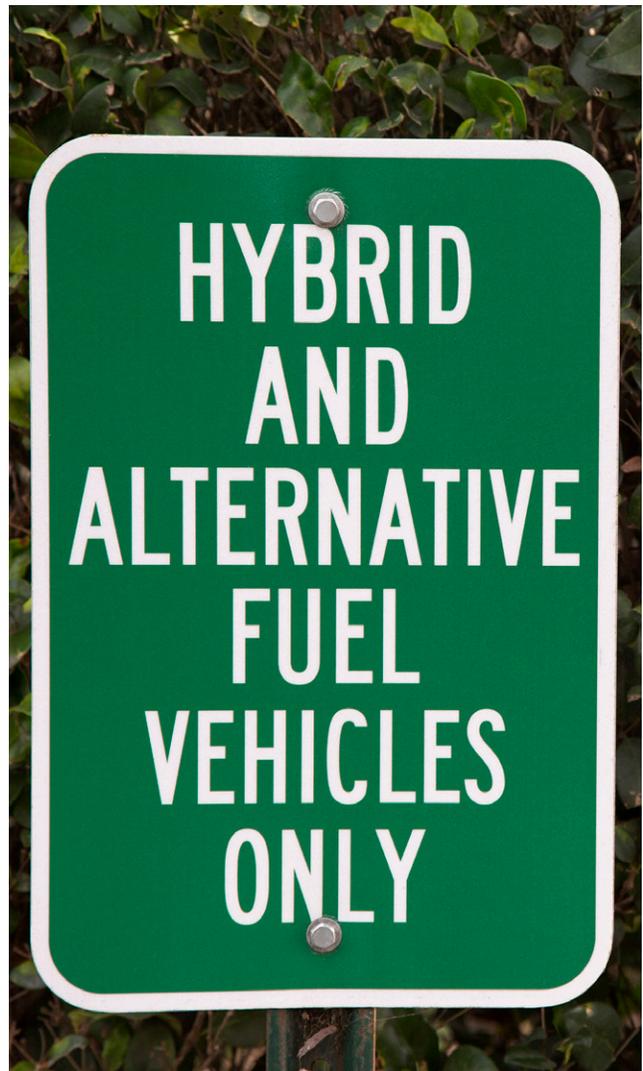
- **Falling Battery Costs:** With battery costs likely to fall dramatically in the next 10 years,⁶ Bloomberg New Energy Finance projects that unsubsidized EVs will become cheaper to own than internal combustion engine vehicles between 2020 and 2030.⁷
- **Shared Economy and New Mobility Services:** On-demand mobility services such as Uber and Lyft may result in declining private-vehicle sales and automotive revenues. However, this decline is likely to be offset by increased sales or leasing of EVs for sharing or fleet applications. Since shared vehicles drive more miles than private vehicles, shared EVs have a stronger economic advantage than shared internal combustion engine vehicles. The higher utilization rates also increase overall daily charging needs, rapidly accelerating the potential for EVs to serve as a grid resource.⁸
- **Community-Driven Energy Policy:** Local municipalities are increasingly interested in energy procurement and management options that enable more control over their energy supply and resilience. Policy tools like climate action plans (CAPs) and community choice aggregation (CCA) will shift energy decision making toward the community level. An increasing proportion of EV deployment and infrastructure investments will be driven by local air pollution requirements, enabling more rapid growth in ambitious, organized communities.

This geographic concentration of EV loads will be driven by intercity patterns of EV adoption, where dense, higher-income cities with compelling customer incentives, strict vehicle emission regulations, and corridors to other metro areas will have higher adoption than less dense areas with a higher dependency on driving range and insufficient charging infrastructure.⁹ EV loads will also concentrate within cities, especially in particular residential neighborhoods; at high-density locations such as campuses, shopping centers, and military bases; and at hubs for mobility-as-a-service businesses and fleets.

Because EV impacts emerge in concentrated areas at the distribution system level, regulators have a near-term opportunity to proactively consider smart charging and deployment policies that harness the benefits of EV charging and avoid its challenges, even at ostensibly limited levels of market penetration—about 1 percent share of annual sales of cars.¹⁰ Yet EVs are unique electricity system assets that cross traditional regulatory jurisdictional boundaries. Enabling smart EV load management and deployment policies requires the involvement and coordination of many traditional and nontraditional stakeholders.

Further, cost-of-service regulation, used mostly to oversee utilities' investments in large capital-intensive equipment, has changed little over the last 100 years. To respond to the opportunities and risks created by EVs, regulators will need a better understanding of customer behavior, business model viability, and system architecture needs. This suggests a much more flexible regulatory approach, with policy experimentation through mechanisms like pilots and more informal forums outside conventional procedural processes.

By engaging early in addressing the opportunities and risks created by EVs at the distribution level through smart charging policies, regulators can help meet critical climate goals in a way that supports grid needs and enables society to capture the additional value from EVs as grid assets.





GRID-TO-VEHICLE VALUE STREAMS

A range of stakeholders, from individual customers to the bulk transmission grid, can benefit from the additional value from using EVs as grid assets through well-designed ratemaking and aggregation policies. Below, we outline potential EV value streams for different stakeholders and suggest policies required to both enable smart charging and tap into those value streams.



ADDITIONAL BENEFITS FROM ELECTRIC VEHICLES WITH VEHICLE-TO-GRID CAPABILITIES

Current commercial EV models only charge from the grid as opposed to bidirectionally, in which they also provide power back to the grid. Although these EVs can provide value from smart charging, they cannot offer the same suite of services as precommercial automobiles that can charge bidirectionally (V2G). When these more technically advanced vehicles become commercially available, bidirectional-charging functionality will increase the up-front cost of EV ownership, but will provide the following benefits:

- EVs could deliver backup power services by keeping power flowing during a grid failure, creating reliability and resilience benefits for customers.
- Aggregated EVs could provide energy arbitrage services by supplying stored energy back to the grid during peak demands or when nearby generation sources have an outage. And although demand-side EVs can provide frequency response, V2G vehicles can provide twice the level of frequency response services.
- EVs can also provide distribution congestion relief by charging during a noncongested period and discharging downstream of the congested node. There may also be potential for EVs to provide transmission congestion relief in the future, although this depends on considerable system-level EV growth.

EV CUSTOMERS (PARTICIPANTS)ⁱⁱⁱ

The largest set of EV benefits to customers comes from the value that they can capture today in the form of reduced operational costs. Per mile driven, electricity (\$/kWh) is less expensive than gasoline (\$/gallon), creating cost savings for EV drivers. In the limited set of states with time-differentiated rates, EV owners may be able to lower their bills further by charging at beneficial times for the grid. To do so, they may change when and where they charge their cars in response to price signals or take advantage of rates that fit their existing driving patterns.

Research shows that EV drivers will respond to time-differentiated rates. A study by the California Public Utilities Commission found that throughout the state, time-of-use (TOU) rates were successful in shifting EV charging times from the evening hours (roughly 3 p.m. to 9 p.m.), when residential loads typically peak, to the off-peak hours (midnight to 2 a.m.).¹¹ However, the extent to which participants have the flexibility to respond to these signals will determine whether or not TOU rates produce a net benefit for them by reducing their overall electricity bill. Similarly, EV customers with access to rates that price peak demand and the flexibility to respond to these rates could lower their bills by shifting EV charging away from peak times. EV owners in states that have solar self-consumption rates and incentivize on-site consumption, such as Hawaii, can maximize self-consumption of their PV resources rather than export them to the grid at a lower rate by choosing to charge EVs at home.^{iv}

Although many states are experimenting with time-differentiated rates, few have locational- or attribute-differentiated rates in place for any DERs,^v and utilities may find these more advanced rate designs difficult to implement until EV penetrations increase dramatically. Beyond altering individual charging behavior, EV owners may also receive payments for participation in demand response or ancillary grid services through aggregation. To capture these value streams, regulators should expose EV customers to granular time, locational, and attribute-based rates that incentivize grid support, either directly or through aggregators.

UTILITY RATEPAYERS (NONPARTICIPANTS)^{vi}

All utility customers can also benefit from EV-supportive policies such as TOU and dynamic rates that encourage off-peak charging. When EV customers respond to these time-varying rates, utilities can improve capacity utilization on the grid and lower operating costs. These reduced utility costs translate into lower bills for all customers, whether or not they own an EV. A recent analysis conducted by Energy and Environmental Economics (E3) shows that all California utility customers are likely to benefit from the additional revenue provided by EV smart charging.^{vii} For the four rates and charging load shape scenarios studied, this additional revenue from EV charging creates positive net revenues that put downward pressure on rates.¹² To capture these value streams, states need policies that support more sophisticated rate structures and

ⁱⁱⁱ In this report, we use the term “participant” to indicate an EV customer who is providing vehicle grid integration.

^{iv} Solar self-consumption rates are utility rate structures like non-export tariffs, which are unfavorable to the export of electricity generated by behind-the-meter solar PV.

^v Attribute-based ratemaking describes parsing an energy resource into its specific value components through partial or total unbundling of electricity rates. The goal is to match services that a given resource can provide with the needs of the grid to unlock greater value to the customer and to the grid (e.g., energy, capacity, and ancillary services). See more in RMI’s *Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future*.

^{vi} In this brief, we use the term “nonparticipants” to refer to all utility ratepayers.

^{vii} E3’s analysis uses a Ratepayer Impact Measure Test for this cost-benefit analysis.

demand response programs that include EV customers. States also need two-way, real-time telemetry and communication systems that send efficient price signals to customers. Where states invest in charging infrastructure, they should facilitate optimal siting so that EVs can be charged in the places that enable them to add value to the grid.

UTILITY SHAREHOLDERS

Where allowed by regulators, utility shareholders may see opportunities to earn a return from investments in charging infrastructure or new distribution infrastructure to serve new loads, contingent on how regulators view the role of the utility in EV infrastructure investment.¹³ With smart charging, utility shareholders may also benefit from the cost savings created by improved grid capacity utilization. Optimal integration of EVs as flexible loads can lead to more efficient system operations and investment, which could be converted into higher rates of return for shareholders through performance-based ratemaking mechanisms.¹⁴ To capture these value streams, states should ensure that utility incentives align with a more efficient grid, and regulators should provide a stable regulatory environment so shareholders have reasonable confidence that necessary and prudent investments by utilities in EV infrastructure will earn a rate of return.

DISTRIBUTION GRID

If EVs are charged during peak demand, the increased load may require additional distribution system infrastructure (absent lower loads on those circuits from energy efficiency and other distributed energy resources). However, upgrades can be avoided if loads can be shifted to the “valleys” of load profiles—when energy demand is low and significant supply is available. Loads can be shifted through policies that monetize distribution grid value—using transactional mechanisms that allow DERs to provide energy and capacity value—providing significant societal benefit from incrementally deferring or avoiding the need for upgrades as a result

of these resources themselves. To capture these value streams now or in the future, state regulators should define rules for EV participation in electricity capacity procurement processes, including locational requirements, so that mobile resources can participate. State regulators should also require submission of distribution system plans that consider EV resources.

BULK TRANSMISSION GRID

Aggregated demand-side EV resources could also deliver value at the wholesale level through ancillary grid services. EVs could provide frequency regulation by removing their loads from the grid when an imbalance between supply and demand causes the regional grid frequency to shift above a nominal value, helping return grid frequency to the band required to avoid grid instability events. With the right economic incentives, EV chargers could be equipped to provide voltage regulation, even when vehicles are not charging. Additionally, demand-side EVs could serve as non-spinning reserves—demand response resources that can be called upon to address unplanned capacity losses experienced by the electricity market to the extent that such curtailments do not interfere with meeting the driver’s trip requirements. To capture these value streams, minimum discharge duration requirements in bilateral contracts for ancillary services and wholesale ancillary markets would need modification where they preempt EV participation. To enable voltage regulation, regulators should update interconnection standards to allow EV charger participation.



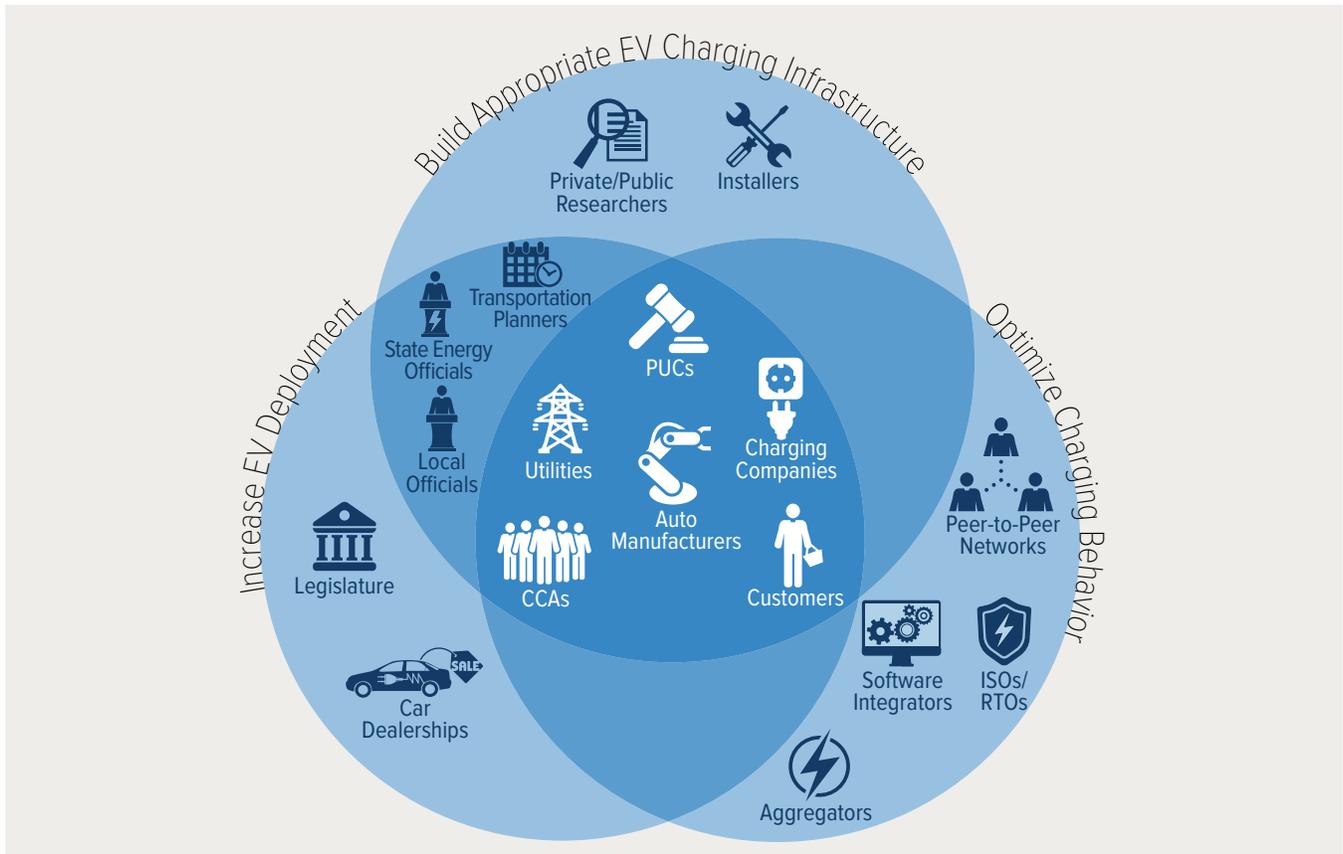
STAKEHOLDER ALIGNMENT

The potential value streams described above depend on the actions of a diverse set of actors with varying responsibilities and objectives. A range of stakeholders can tap into the demand response value of EVs, but only through well-designed policies that enable smart charging through three broad buckets that:

1. Increase EV deployment so that EVs are on the road and able to provide demand response services;
2. Build appropriate EV infrastructure that supports that deployment and optimal charging, and that meets customer charging and system needs; and
3. Optimize charging behavior through signals and controls to those EVs.

Unlocking this demand response value hinges on the customer's agreement to participate in smart charging and successful deployment and coordination among many other entities. The EV Deployment and Integration Stakeholder Map (Figure 1) outlines the variety of stakeholders needed to achieve each of these objectives and highlights the coordination challenge for any one entity, such as regulators, in achieving its smart charging goals. Regulators and utilities understand grid needs and constraints, and can influence charging rates and availability, but have limited influence over the pricing and incentives for EV purchase to increase deployment. In contrast, auto manufacturers directly influence the pricing and incentives for EV purchase and the provision of on-board charging controls, but may not have information about grid needs for optimal siting.

FIGURE 1
EV DEPLOYMENT AND INTEGRATION STAKEHOLDER MAP



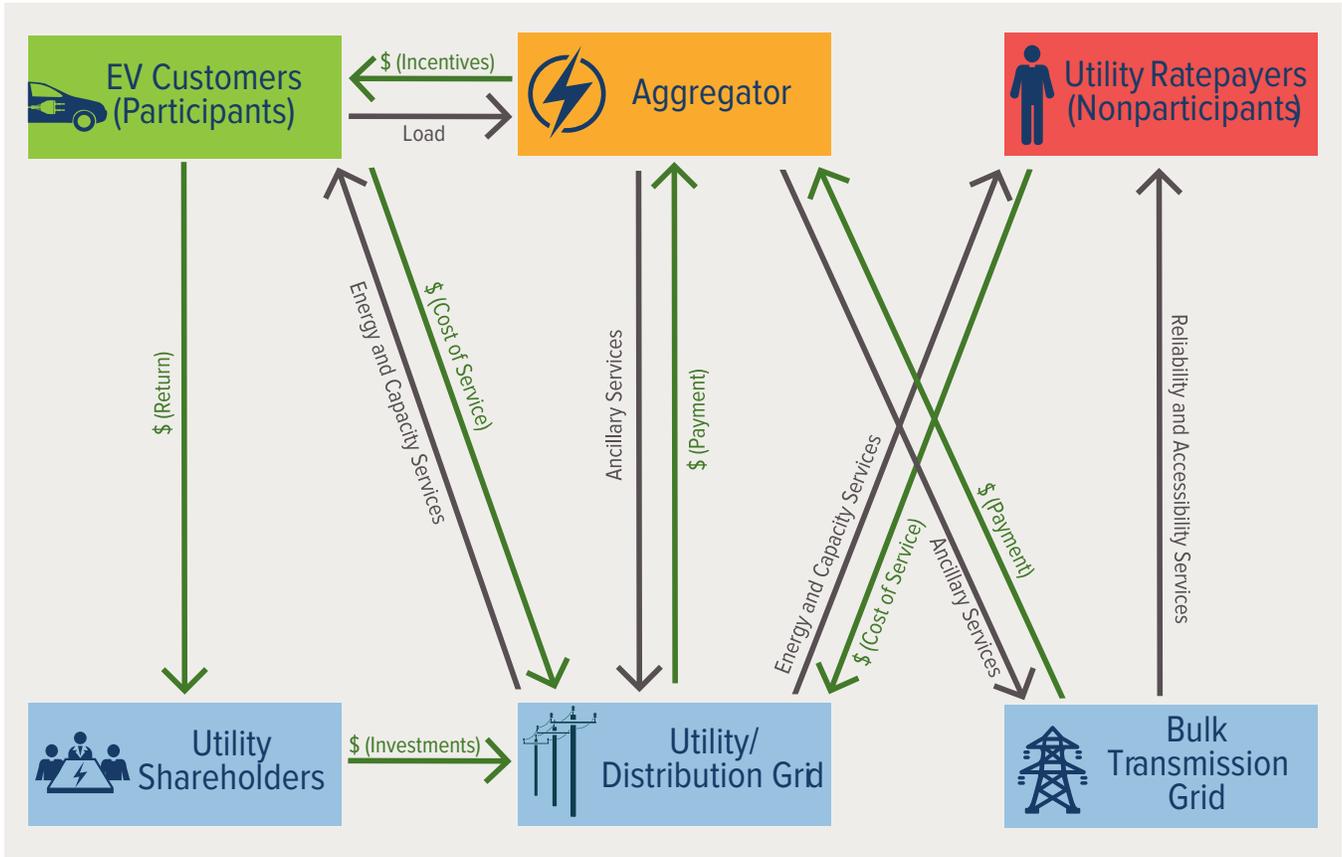
As different value streams flow to various market participants, it is easy for misalignment in objectives to arise. Smart EV Charging: Actors and Resource Flows (Figure 2) shows how costs and benefits can easily become interdependent when different entities rely on one another for varying forms of revenue, services, and load. Workplace charging may represent one such opportunity for misalignment. In the case where three entities have different owners—the employee EV, the network charging station, and the employer facility—there could be three different, and potentially conflicting, workplace charging objectives:

to do what is optimal for the EV customer’s mobility, the grid, or the facility’s overall costs. The employee may want to charge her EV so she has a full battery to drive home from work at the same time that the network charging station may want to respond to frequency regulation signals in order to reduce the cost of “duck curve” ramping^{viii} in the afternoon and the facility may want to reduce its demand charge.¹⁵ Only if market participants take synchronized actions by coordinating pricing and control signals and charging responses will the system maximize overall EV grid integration benefits.



^{viii} The “duck curve” illustrates the ramping rate and range needed when there are significant fluctuations between renewable generation and demand on the bulk grid system throughout the day. At certain times of the year, the difference between generation and demand (net load) produces a “belly” appearance in the midafternoon that quickly ramps up to produce an “arch” similar to the neck of a duck. The curve was originally created to show a typical spring day in California with a high midday solar PV load.

FIGURE 2
SMART EV CHARGING: ACTORS AND RESOURCE FLOWS



The stylized model above shows the exchanges of payments and services that smart charging unlocks for different market players. The model assumes:

1. Participants are not big enough to provide ancillary services alone, but are consistently smart charging
2. There is a need for the ancillary services and distribution capacity provided by smart EV charging
3. There is no distinction of the primary purpose for the smart EV charging (bulk transmission grid services vs. distribution grid services)

EV INTEGRATION AND DEPLOYMENT IN ACTION: CASE STUDIES



EV INTEGRATION AND DEPLOYMENT IN ACTION: CASE STUDIES

To explore states' divergent regulatory approaches to EV deployment and integration, we highlight two of the top states by EVs per capita in the country that are projecting continued EV growth in the upcoming years—California and Washington:

- California has the highest concentration of EVs in the country with 4.68 EVs per 1,000 people.¹⁶ The state has an official target of 1.5 million EVs by 2025 and a law requiring that utilities procure 50 percent of their electricity from renewables by 2030.
- Washington has goals for 50,000 EVs by 2020, and created one of the most comprehensive statewide EV Action Plans in response to climate concerns.

Although these states may have different policy drivers, they are both actively working to unlock the benefits of EVs through pilots, collaborative efforts, and new policies that explore rate design and the role of utilities in infrastructure ownership, operation, and maintenance. Below, we present a snapshot of the story of EV market development in each state to provide the context for exploring how each state is or is not addressing six key regulatory questions.



CALIFORNIA

California, the leading state for EV penetration with almost 200,000 EVs on the road today,¹⁷ has accelerated EV deployment through a series of executive and legislative actions. Driven by California's goals to reduce localized pollution, limit greenhouse gas emissions, and enable continued

economic growth, Governor Brown issued a 2012 executive order targeted at getting 1.5 million zero-emission vehicles (ZEVs)^x on the roads by 2025.¹⁸ This executive order was translated into the ZEV Action Plan¹⁹ and the Vehicle-Grid Integration Roadmap,²⁰ which laid out roles and objectives for future EV activities in the state.

In response, a wide range of actors, including the three large electric investor-owned utilities (IOUs), initiated business and government program activity to accelerate EV deployment. In 2014 and early 2015, three California investor-owned utilities proposed pilot applications to expand utility investment in EV infrastructure in areas likely to be underserved by competitive infrastructure markets or that could present market failures like multiunit dwellings and workplaces. SCE and PG&E also proposed installing publicly accessible charging infrastructure.

In the midst of the California Public Utilities Commission's (CPUC) consideration of these pilot applications, the state legislature passed SB 350, which made two major changes to incentivize EV deployment and integration. First, it requires utilities to plan for transportation electrification in their integrated resource plans (IRPs). It also requires the CPUC to approve future utility applications for EV programs and investments that accelerate widespread transportation electrification.²¹ While SB 350 specifically identifies EVs as being important for multiple objectives—grid management, integration of renewables, and reduction of fuel costs for drivers who charge in a manner consistent with grid conditions²²—it also limits the public investment in EVs to integration and deployment activities that are in the

^{ix} In California, zero-emission vehicles (ZEVs) include hydrogen fuel cell electric vehicles (FCEVs) and plug-in electric vehicles (PEVs), which include both pure battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs).

^x SB 350 describes "interests" of ratepayers as short- or long-term, mean direct benefits that are specific to ratepayers, consistent with both of the following: (1) Safer, more reliable, or less costly gas or electrical service, including electrical service that is safer, more reliable, or less costly due to either improved use of the electric system or improved integration of renewable energy generation; or (2) Any one of the following: improvement in energy efficiency of travel, reduction of health and environmental impacts from air pollution, reduction of greenhouse gas emissions related to electricity and natural gas production and use, increased use of alternative fuels, or creating high-quality jobs or other economic benefits.

interest of all ratepayers.^x These interests are defined as short- or long-term direct benefits that are specific to ratepayers,^x consistent with safer, more reliable, or less costly electrical service due to either improved use of the electric system or improved integration of renewable energy generation.²³

With SB 350's new directives and definitions, the CPUC revised the guiding principles it uses when approving the utilities' applications. The CPUC considered these utility requests on a case-specific basis by using a balancing test created in a previous decision to weigh the benefits of utility ownership against limitations on competition.²⁴ The CPUC had been gradually liberalizing its position on utility EV infrastructure ownership since before both the ZEV Action Plan and SB 350, and this represented a new, more flexible approach to these investment requests. The CPUC approved pilots for SCE and SDG&E in early 2016 with smaller budgets than proposed, explaining that the use of a more limited, phased approach with increased reporting and oversight will ensure ratepayer protection, promote fair competition, and meet specific and measurable outcomes.²⁵ A September 2016 ruling began the next stage of IOU involvement in transportation electrification, requesting that the IOUs design and submit programs and pilots to target electrification of all mobile pollutant sources in early 2017.²⁶

With the approval of these pilots, as well as other IOU-led initiatives, California leads the country in EV pilots in terms of diversity, scope, and scale. Addressing EV rate design, all three utility pilots include time-varying rates for EV customers, with SDG&E even experimenting with dynamic, advanced

rate designs spanning across multiple dimensions. The utility pilots also offer a diversity of different ownership and aggregation models and roles for third parties, and are testing how to capture the value of EVs using existing demand response programs, like the Demand Response Auction Mechanism (DRAM) and the IOU demand response portfolios.

Beyond pilots, California is at the forefront of defining the questions utility regulators need to ask in order for EV resources to be aggregated and used as demand response resources and for ancillary grid services (see, for example, the CPUC's Energy Division's 2014 report, *Vehicle-Grid Integration*²⁷). The state is adapting policies as these conversations evolve. For example, in its distribution resource planning (DRP) and integrated distributed energy resources (IDER) proceedings, the state is rethinking the valuation, planning, and integration of distributed energy resources, including EVs.

Although California has led the nation in EV policies, the state needs to increase its current number of EVs by 600 percent in the next nine years to reach its ambitious 2025 goal.²⁸ Additionally, the state's regulators face further questions to unlock the full range of renewables integration benefits from EVs and avoid costly overinvestment. For example, the state still needs a more iterative process between forecasting, planning, and resource acquisition for comprehensive integration of EVs into its distribution grid planning. Nevertheless, California's experiences with policy direction, utility pilots, and cross-agency coordination^{xi} will provide insight for states looking at how to maximize EV benefits for stakeholders, especially for regulators in the other seven ZEV states.^{xii}

^{xi} The California Energy Commission (CEC) also has played a significant role in EV deployment and infrastructure investments and has funded over \$200 million in EV projects. About a quarter of this funding went to projects specifically focused on EV infrastructure.

^{xii} Beyond its individual state goals, California also signed a memorandum of understanding with seven other states in 2013 committing to collectively have at least 3.3 million ZEVs operating on the state's roadways by 2025. The other seven states are Connecticut, Maryland, Massachusetts, New York, Oregon, Rhode Island, and Vermont.



WASHINGTON

Washington has the third-highest EV adoption rate in the country, with about 16,000 registered electric vehicles as of December 2015.²⁹ Like California, Washington's EV deployment is heavily propelled by state executive-driven environmental and innovation policy, and the utility and regulatory roles in EV infrastructure investment in the state are just beginning to be shaped.

In 2014, an Executive Order directed the Washington State Department of Transportation (WSDOT) to develop an action plan to advance EV use, including strategies, incentives, and policies for a broad range of private and public actors.³⁰ The governor also directed the WSDOT to continue to build out the EV charging network along state highways and at key destinations. The executive order resulted in the WSDOT's EV Action Plan ("the Action Plan"), which describes multiagency collaborative actions necessary to increase EV deployment to meet the state's target of 50,000 EVs by 2020 in three areas: EV sales incentives and outreach, charging infrastructure, and regional coordination.³¹

Consistent with the Action Plan's recommendations, the legislature passed HB 1853 in 2015, which directs the Washington Utilities and Transportation Commission (WUTC) to allow utilities to own EV infrastructure that is deployed for the benefit of ratepayers.³² In response to the law, Avista submitted a proposal to the WUTC for a two-year pilot program to install Level 2 chargers at residential homes, workplaces, multiunit dwellings, fleet locations, and in public areas. The pilot also proposed to install smart chargers in a number of locations. Although the WUTC allowed Avista's pilot to proceed, it acknowledged the need to provide more direction on several policy issues.³³ As follow up, the WUTC is currently soliciting comments on pending regulatory questions regarding utility ownership and ratepayer benefits, among others, and will be holding an open meeting to discuss these issues in September 2016.³⁴ These responses and the resulting conversation could lay the foundation for a more formal rulemaking at the WUTC.

However, the focus of Washington's EV activities cannot be limited just to the IOUs operating in the state, given that the three IOUs regulated by the WUTC supply only about half of the state's power. More than 50 publicly owned utilities (POUs), cooperative utilities, and tribal entities supply the rest. As a result, legislation focused on providing rules and directives for the POUs and other utility structures may be necessary for comprehensive EV deployment and integration in the state. For example, while HB 1853 allows Washington's IOUs to rate base EV infrastructure, the POUs in the state do not yet have similar legislation in place. Nevertheless, Seattle City Light, a publicly owned utility in a city with one of the highest EV concentrations in the country, is planning to pilot different EV infrastructure ownership models in residential and commercial spaces, along with possible new residential rate designs better aligned with grid needs.³⁵

Washington is largely not considering EVs' potential role as a distributed resource, instead focusing on the opportunities created by their deployment for carbon mitigation and new load growth for utilities. This is largely because of the abundance of low-cost hydropower, which is relatively stable on a day-to-day basis, and a lower penetration of variable renewables penetration. These conditions have prevented stresses on the state's current system like those in California and ensured some of the lowest retail rates in the country.

Washington does, however, have an opportunity to leverage EV loads to integrate new overnight wind power, especially in light of coal plant retirements.³⁶ The Northwest Power and Conservation Council includes EV load in its forecasts, projecting 16–65 times the average EV load in 2014 by 2035.³⁷ Although the state's comprehensive energy efficiency policies may address this increased load—the estimated average EV load is only about 10 percent of the energy efficiency savings the state is expected to achieve over the same period—EVs still have potential to act as demand response resources.

Beyond the state's utility activities, other entities in Washington are providing support to accelerate EV deployment and integration. The legislature provided \$1 million in funding to WSDOT to develop a pilot program to strengthen and expand the West Coast Electric Highway by encouraging private investment in EV fast charging along highway corridors.³⁸ WSDOT plans to award grants to qualifying government agencies such as cities, towns, counties, transit agencies, and tribes to help fund EV fast-charging stations.

STATES TO WATCH



HAWAII

Hawaii's goal to reach 100 percent renewable energy by 2045 will require EVs to play a role in grid stabilization. Although there have been limited utility EV pilots to date, stakeholders in the state are in the process of developing a collaborative initiative with a goal to electrify 100 percent of Hawaii's light-duty vehicles and mass transit and will set forth a shared vision and high-level strategy to reach it.



OREGON

Oregon is one of the top five states in EVs per capita. Similar to California's SB 350, Oregon's recently passed SB 1547 orders the state's public utility commission to direct the electric utilities in the state to file applications for transportation electrification programs. These programs may include utility investments in or customer rebates for EV charging and related infrastructure.



NEW YORK

New York City utility Con Edison is considering a new demonstration project as part of the state's Reforming the Energy Vision (REV) initiative that seeks to develop a comprehensive electrification strategy for local transportation to reduce the city's carbon footprint. At e-Lab Accelerator 2016, city stakeholders came together to develop a shared vision of an electric vehicle future in New York City, a clear set of objectives for Con Edison to help achieve this vision, and a set of requirements to focus Con Edison's upcoming vehicle electrification demonstration project (an electric passenger-miles-travelled metric and a path toward net positive cash flows in 5–10 years).

KEY REGULATORY QUESTIONS



Charging stations at San Francisco City Hall
Image courtesy SA Felix Kramer CC BY 2.0

KEY REGULATORY QUESTIONS

The California and Washington cases highlight some of the choices and options regulators need to consider for capturing the value of EV integration in two leading states:

- **Collaboration Methods:** Both Washington and California have engaged key stakeholders through comprehensive state EV Action Plans, multi-stakeholder meetings, and coordination among various state-led initiatives.
- **EV Purpose:** Washington's EV efforts focus on deployment, whereas California's efforts include a dual focus on EV deployment and grid integration.
- **Rate Design Emphasis:** Washington's efforts have initially focused on determining a baseline for customer charging using flat EV rates. In contrast, TOU rate design plays a major role in California's efforts.
- **Source of Utility Ownership Decisions:** In both Washington and California, legislation provided the initial driver to allow utilities to include EV infrastructure investments in their rate base. The CPUC in California has played a significant role in the utility ownership decision throughout the years, whereas the WUTC recently opened an investigation into the issue this summer.

Below, we offer a series of universal questions intended to assist regulators who may initiate or are actively engaged in regulatory proceedings surrounding EV deployment and integration.

1) How much of a role should utility regulators play in enabling EV integration or deployment?

Utility regulators have a role to play in enabling the integration of EVs onto the grid where it minimizes costs and maximizes value to ratepayers over time and ensures the provision of safe, reliable electricity service. EVs present challenges to effective grid management, as they will likely be initially concentrated on particular distribution circuits, leading to grid stress, congestion, and, potentially, additional grid upgrades. Regulators can encourage and incentivize grid operators to avoid those costs, especially since the technology to make EVs grid-responsive already exists and is often already embedded in vehicles and charging equipment.

Additionally, in states with high renewables penetration, well-integrated EVs can help minimize renewable energy curtailment, avoiding cost increases and potentially reducing rates in the process. California, a state with high renewables penetration, used legislation to explicitly mandate a role for regulators in grid management and fuel cost reductions for EV drivers. The CPUC is required to approve prudent utility EV infrastructure investments and oversee planning



processes that now require utilities to plan for transportation electrification.³⁹

EV deployment is more complicated. EVs have to be on the road in order to actually be used as grid assets. But EV deployment itself may seem well outside a regulator’s typical authority, even though regulators can encourage adoption by reducing the price of EV charging or supporting the build-out of charging infrastructure so customers feel comfortable purchasing EVs. Regulators will also need to consider impacts on competition, ease of deployment, and equity. In California, legislators explicitly make the connection between deployment and integration, requiring the CPUC to coordinate deployment activities among state agencies.⁴⁰ In Washington, the WSDOT Action Plan directs legislators and regulators to mandate utilities to support increased transportation electrification by modifying energy conservation and carbon reduction mandates to allow for load growth from EVs. The Action Plan also encourages utility support of electric vehicle supply equipment (EVSE) installation and rebates.⁴¹

Both successful EV integration and deployment will require that consumers have the information, context, and behavioral cues needed to respond to or delegate their response to pricing signals. For example, Washington’s Action Plan explicitly encourages utilities to provide public EV education, and all three of California’s recent IOU pilot proposals include a customer education component.

Some policy levers, like incentivizing EV purchases, do not fall neatly within the utility regulator’s explicit authority. Despite these limitations, regulators can still support initiatives that partner with other entities to more comprehensively address market needs. For example, to ease the economy’s transition from internal combustion engine vehicles to EVs, regulators should work with other state decision makers to support alternative forms of revenue, like annual EV fees or vehicle-miles-traveled charges, to substitute for gasoline-based taxes used to

build and maintain transportation infrastructure. However, even with rate design, a core part of the regulatory role, there may be limitations to their influence—EVSE companies may receive rates as cost inputs, but charge other prices depending on the contract with the EV owner or the site host. Some policy levers, like incentivizing EV purchases, do not fall neatly within the utility regulator’s explicit authority.

2) What factors will utility regulators have to consider when they evaluate the public interest in the context of EVs?

Regulators have varying degrees of freedom to promulgate rules based on how they define what is in the public interest. In so doing, they will balance competing sets of public interests when shaping policies on EV-charging rate design, charger siting and planning, and the utility’s role in EV infrastructure ownership.

As with other utility investment decisions, regulators will face the need to balance the interests of ratepayers with those of state taxpayers more broadly. For EVs, this can mean deciding between supporting utility infrastructure investment that benefits the local utility customers or supporting infrastructure that may benefit non-ratepayers, like highway fast charging between cities with municipal power. One factor that utility regulators must also consider is the appropriate time horizon for considering costs to different groups, as uneven EV growth dynamics may shift the benefits of utility EV infrastructure investments to non-EV-owning ratepayers into the future. Further, regulators need to decide how much public funding is necessary in addition to private investment to support market transformation.

California clearly articulated a decision in rulemaking and legislation about both the relevant frame of analysis—as “direct benefits that are specific to ratepayers, consistent with safer, more reliable, or less costly electrical service due to either improved use of the electric system or improved integration of renewable energy generation”—and the time frame for analysis—as “short-term or long-term.”⁴² Washington’s

HB 1853 directs the WUTC to allow utilities to own EV infrastructure that is deployed for the benefit of ratepayers, which is measured by ensuring that utility capital expenditures do not increase costs to ratepayers in excess of one-quarter of 1 percent.⁴³ The WUTC is currently exploring the criteria needed for utilities to demonstrate those “real and tangible benefits for ratepayers.” It issued a Notice of Opportunity to File Comments to explore these questions, including whether utilities should earn a rate of return on investments that serve only the company’s electric customers or the public at large, and which alternative cost-effectiveness tests should be utilized for these utility investments.⁴⁴

3) What tools do utility regulators have to encourage effective grid integration and optimal siting?

To capture the potential value from EV integration, utility regulators should work with utilities to provide customers access to rates and signals that incentivize charging during the times of the day when energy demand is low and significant supply is available. In doing so, regulators should evaluate both system-focused rates that encourage charging during certain times and at certain locations based on their jurisdiction’s grid needs, and customer-oriented rates, which incentivize charging in convenient locations that influence customer adoption.

Rates will need to evolve along with changing grid needs and customer behavior. California is moving in the direction of more time-based rates for all mass-market customers,⁴⁵ and has had opt-in EV TOU rates in place for a long time, with marked success in influencing behavior.⁴⁶ SDG&E is testing more dynamic rates that reflect hourly wholesale electricity prices, local distribution constraints, and the availability of renewable energy. In Washington, Avista purposely provides a flat rate to residential customers in its pilot to determine a baseline for customer charging behavior, and specifically to determine how much peak load may be shifted to off peak without TOU incentives while maintaining high customer satisfaction.



Although more sophisticated time-, location-, and/or attribute-based rates can incentivize charging behavior that supports optimal grid operations, these must be balanced with measures that are easy to interact with and more understandable for customers. The spectrum of control customers can have over their charging decisions ranges from full customer control to direct control by utilities and aggregators, with hybrid options in-between that enable consumers to articulate and then automate preferences. Aggregators or EVSE companies can help provide the intermediation needed to simplify rates for customers. In California, demand response pilots are currently testing different models for intermediation between EV customers and utility rates through aggregation.^{xiii} Another powerful way to effectively engage customers is by coupling any switch to a new rate with enabling technology (in this case, software to control EV charging). In cases where enabling technology was coupled with dynamic rate adoption, average peak reduction for participating customers jumped from 10 percent to 30 percent.⁴⁷

In addition to designing smart, dynamic, easy-to-understand rates, it will be important to consider where charging infrastructure is deployed in order to support grid operations at the right time of day. This includes the actual charging equipment and complementary integration technologies, such as advanced metering infrastructure and transformers. For example, daytime public and workplace charging infrastructure and associated rates are increasingly needed across California and Hawaii to soak up excess midday solar production. But in Texas, infrastructure and supporting rates are better suited to nighttime home charging considering the state's large nighttime wind resource.

Finally, as with all DERs, regulators can support a multi-stakeholder conversation about how to prioritize possible grid benefits, and then prioritize signals sent to grid-enabled EVs such that charging responses produce the desired benefits. Coordination of services and settlements is needed from both a technical and participant perspective. For example, EVs may face binding constraints along the different levels of the system (charger, meter, substation, etc.) that may hinder the complete set of benefits from reaching their end destination. If an EV battery is fully charged, and the utility decides it needs to increase load on the distribution grid to absorb excess generation, the EV will be limited in its ability to serve as a resource at subsequent nodes of the system. To address this challenge, "rules of the road" must be determined where signals from different levels of the system contradict each other. In California, the CPUC and the California Independent System Operator (CAISO) are currently working together to figure out how to prioritize signals sent to EVs such that the response in EV customer charging behavior optimizes benefits to the system overall.

4) Who should own, operate, and maintain charging stations, and what types of incentives should be provided to encourage EV integration and/or deployment through those roles?

Although several different entities could own EV charging stations, state utility regulators will need to decide under what conditions justification exists to allow utilities to own EV infrastructure in their jurisdiction. It may be appropriate for utilities to own EV infrastructure under certain conditions: if ownership results in net benefits for ratepayers or there are market segments that a competitive market is unlikely to serve.

^{xiii} Examples include: 1) eMotorWerk's pilot with all three large electric utilities that uses California's DRAM mechanism to bid EV resources into CAISO's day-ahead market; 2) BMW's pilot that focuses on using BMW i3 EV customers and EV batteries repurposed as stationary storage as part of PG&E's Demand Response program; 3) the Department of Defense's pilot that aggregates EVs in Los Angeles Air Force Base's fleet and bids these resources into the CAISO's energy and ancillary service market; and 4) Shell's pilot that aggregates SDG&E fleet vehicles and also bids these resources into the CAISO's energy and ancillary service market.

Where these situations do exist, regulators should design rules and incentives for utilities that encourage investment but do not unfairly promote utility involvement beyond that underserved market.

States have found that utility ownership of EV infrastructure is in ratepayers' interest in certain situations and therefore allow utilities to include those investments in their rate base. Utilities' existing customer relationships, knowledge of the grid, and ability to finance infrastructure with high capital costs may make them uniquely positioned to accelerate charging station deployment for market segments like apartment complexes, workplaces, and public fast charging.⁴⁸ If building out new EV infrastructure has high fixed costs and new market entrants would reduce system efficiency, there may be an argument that one entity should be granted a monopoly over ownership rights.

However, charging infrastructure owned by third parties or procured competitively by utilities may be cheaper than if it's solely utility owned thanks to market competition. Regulators should consider the potential economies of scale and scope enabled by private EV charging companies that operate across state boundaries from their build-out and operation of EV charging stations, including installation, billing, and marketing. Charging networks can also share interoperable communication protocols and software, allowing these networks to overlap without wasteful duplication and providing customer choice and competition.

Recognizing the need to balance these perspectives, the CPUC has liberalized utilities' ability to own EV infrastructure over time, allowing ownership in cases of "underserved markets" or "market failures," but balanced against the need to avoid limitations on competition.⁴⁹ It is now considering utility requests on a

case-specific basis, using a preestablished balancing test.⁵⁰ In Washington, the WUTC is soliciting comments on pending regulatory questions regarding utility ownership, while Avista tests charger ownership at residential homes, workplaces, multiunit dwellings, fleet locations, and in public areas.

Beyond exclusive ownership, utilities have the potential to play a wide range of important roles in EV infrastructure deployment, operations, and maintenance. Utilities are experimenting with several of these roles, perceiving a range of opportunities to support customers and earn profits from EV deployment and integration. These options include the following roles:⁵¹

- **Facilitator:** Utilities provide service to charging stations like any other load as requested,^{xiv} but have no role in the business of charging.
- **Manager:** Utilities manage the operation and dispatch of EV resources, and possibly the planning of where those resources are sited.
- **Provider:** Utilities act as the owner and manager of charging services, but compete among other third-party companies.

Utilities will be compensated differently for their services depending on the roles they choose or are allowed to perform. For example, in the provider role, the utility can potentially rate-base charging infrastructure and earn a return on investment as it does with other capital. In the manager role, the utility can use more dynamic, granular rates to support operation and dispatch of EVs as resources. For example, it can be paid a monthly service charge that recovers customer-specific costs and a time-varying energy charge to recover all distribution-system and power-supply costs.

^{xiv} Note that when a utility has a facilitator role, it is possible that a customer may not even "request" service to his or her EV and may just begin charging with an L1 or L2, unbeknownst to the utility. This would create a suboptimal solution, suggesting the importance of tracking new EV purchases and infrastructure installations to help both regulators and utilities understand how many EVs are in a given jurisdiction.

In the facilitator role, the utility is paid only for the costs of the electricity provided to the customer or infrastructure operator. Regardless of the utility's role, regulators need to ensure that publicly funded infrastructure is maintained, especially given differing value stream time frames for the utility's set of activities.

For these utility roles, the role of the regulator varies from being fairly noninterventionist—mostly ensuring a level of equitable treatment to both the EV customer and other customers—to a role with much more control—such as setting the retail tariff for EV charging service and governing how the utility is able to use its status with customers to market charging equipment. Regardless, regulators will want to consider their own ability to manage the institutional processes and market design they put in place.

5) What policy support is necessary to enable aggregation so that EVs can provide demand response and ancillary services?

To enable the aggregation of EVs to provide grid and ancillary services, regulators need to first determine at what scale a resource can qualify to serve a demand response or ancillary service function, taking into account the needs of market participants and operators and existing rules and barriers. State utility regulators then need to adjust rules in concert with grid operators to ensure that markets or contractual structures are available to support EV aggregation.

Aggregating EV charging is a promising way to provide demand response and other grid services by taking individual, often geographically dispersed, EVs and scheduling and dispatching them as a single resource.⁵² Designing managed aggregation programs that stagger charging times for different groups can avoid potentially large negative impacts on the grid, such as the late afternoon spike from EV customers charging after work.

However, aggregation can only occur once the EV resource is defined—either as the vehicle, a charging station with an embedded submeter, the primary

facility meter, or an aggregation of resources.⁵³

Providing clear direction over these definitions will ensure the appropriate entity complies with regulatory requirements, and will determine who has ownership of the resource, how the resource is measured, and how communication is managed.⁵⁴ California has de facto defined the EV resource at the primary meter, but there is increasing interest in the state in defining the resource at the vehicle or submeter levels. This downstream definition would better enable the capture of co-benefits like low-carbon fuel standard credits and greater flexibility for customers to manage their energy use. Although market participants are discussing whether or not to actively standardize this resource definition, no consensus has emerged and the CPUC has not acted on its existing authority to put in place standards to ensure interoperability of smart grid devices.⁵⁵ Standardization could more effectively link and coordinate transmission and distribution signals by avoiding the fragmentation of actors involved in charging.

Regulators can support the use of aggregated EVs as grid resources by creating transaction mechanisms with rules that enable these technologies to participate. California state agencies have allowed aggregated DERs to participate in wholesale and retail markets. The CPUC allows EV resources to participate in the Demand Response Auction Mechanism and IOU demand response portfolios, and the CAISO has made tariff modifications to allow for inclusion of more aggregated DERs through its Energy Storage and Distributed Energy Resource (ESDER) and Distributed Energy Resource Provider (DERP) stakeholder initiatives. In response to these changes, California is now one of only a handful of states with active EV aggregation pilots.

Utility regulators can allow different aggregation models to function within their state. EV resources can be aggregated by utilities themselves, by third parties directly, or through a hybrid model that allows utilities and third-party aggregators to compete for EV customers. California has taken the hybrid approach as

Rule 24—California’s rule allowing nonutilities direct access to the wholesale market—allows nonutility aggregators to operate alongside utilities. In each of California’s current aggregation pilots, the operational model includes a third-party aggregator with a direct customer interface, and a variety of different utility roles from billing to end user.

6) What are the processes regulators can use to ensure that regulation is adaptive in this dynamic environment?

Traditional regulatory frameworks and processes will not be sufficient to address the fast-moving, multisided markets created by EV growth. New, more proactive approaches will be required to allow learning through experimentation, including:

- More frequent, assertive use of scalable demonstration projects to test EV integration approaches; and
- More comprehensive consideration of EVs in distribution planning.

To do so, regulators will need to coordinate activities with other state and local entities typically outside their purview through cross-agency collaborative processes. Regulators and utilities should seek a balance between maintaining state or jurisdiction-wide cohesion—often the default posture—and the increasing need to tailor solutions to local needs in both experimentation and planning.

Experimentation through demonstration projects gives regulators some assurance that larger utility investments in the future will not negatively impact ratepayers or lead to other unintended consequences, and enables utilities to experiment with quickly evolving technologies before making more significant investments. In both California and Washington, regulators allowed EV infrastructure pilots, but limited their size to allow for testing before making more broad decisions. The CPUC approved SDG&E’s and SCE’s pilots with scale limitations and increased oversight to ensure that utility intervention creates net ratepayer benefits, minimizes impacts on competition, and results in measureable outcomes.⁵⁶ In Washington, although



the WUTC allowed Avista's pilot to proceed, it acknowledged the need to provide more direction on the impact of utility ownership on fair market competition and other policy issues, delaying a decision due to the limited scope of the pilot and the likelihood that Avista will request rate recovery for EV infrastructure in a future general rate case.⁵⁷

States commonly use pilots and demonstration projects for these learning and ratepayer protection purposes, but many regulatory bodies find it challenging to scale pilots and translate their lessons to larger programs. Pilots are often designed and managed without an eye to collecting data on the measurable outcomes required to enable eventual scaling. In California and Washington, regulators are using their oversight role to track measurable outcomes in each set of pilots. California IOUs propose to expand their pilots in support of the ambitious market transformation goals in SB 350, but this will require continued tracking of the pilots' impact on competition and ratepayer net benefits to enable broader expansion.

Beyond pilots, distribution grid planning will need to evolve from static, deterministic methods toward scenario-based, probabilistic forecasting and valuation tools that better reflect EV adoption and growth patterns.⁵⁸ This shift is already taking place in states that are beginning to move toward more integrated distribution planning and new valuation methods, like in New York's Distribution System Implementation Plans (DSIPs) and California's Distributed Resource Plans (DRPs). Given the dynamic, unpredictable nature of EV deployment, existing planning will be rendered moot unless a wide range of EV growth scenarios are explicitly included as a part of the planning process, including scenarios that consider different approaches to coordinating collective charging behavior.



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LOOKING FORWARD

Most projections suggest strong future EV sales growth, and the emergence of second-generation EVs and new mobility-as-a-service business models indicate that EVs may become commonplace fixtures in home garages, in office parking lots, and along the country's biggest highways sooner than we might think. Although EVs present significant potential benefits to individual end users, utilities, and the transportation and electricity systems, they also present real costs and risks if poorly managed.

Our interviews and conversations with stakeholders in multiple states suggest that regulators should serve a critical role by defining the need for utility intervention and scope of public interest, and then proactively enacting rate design, siting, and market design policies that enable EVs to provide value to multiple actors. California and Washington will remain states to watch and learn from as they continue on their journey toward mass EV deployment and integration, as will emerging states Hawaii, New York, and Oregon.

Looking beyond grid-specific concerns, regulators will need to coordinate with other agencies to consider how EVs fit in to the larger future of mobility as a whole. Consideration of EV deployment in coordination with other objectives, such as congestion reduction and increased use of shared and public transportation resources, will ensure that EV-supportive policies provide maximum value to customers, to the environment, and to the economy.



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1820 Folsom Street
Boulder, CO 80302 USA
www.rmi.org

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