Vehicle - Grid Integration

A Vision for Zero-Emission Transportation Interconnected throughout California's Electricity System

Adam Langton
Noel Crisostomo
Emerging Procurement Strategies Section

Energy Division
California Public Utilities Commission

October 2013

R. 13-11-XXX

1: Executive Summary

Plug-in electric vehicles (PEVs) are beginning to proliferate throughout California's roadways. The widespread adoption of PEVs will be essential to the transformation of the transportation system as the State strives toward substantial improvements in local air quality and the mitigation of climate change. However, greater use of PEVs requires that grid operators prepare for the influx of these potentially sizeable and mobile loads on the electric distribution infrastructure.

Vehicle-Grid Integration (VGI) can harness the usage characteristics of and technologies within PEVs to allow them to serve as a grid asset, reducing operating costs for facility and vehicle owners, the utilities' distribution maintenance requirements, and energy prices in the wholesale market. The size of the vehicle resource and the fact that its primary purpose is for transportation creates special limitations on how this resource can be deployed. Additional pilot demonstrations are needed to quantify the actual costs and benefits of VGI.

In this paper, the Energy Division of the California Public Utilities Commission (CPUC) proposes a framework to characterize VGI and help understand the regulatory barriers to the use of electrified transportation as grid resources. This framework examines VGI on three characteristics:

1) The capability of the resource to provide power to the grid in addition to managing its power draw;
2) The alignment of the objectives of the various actors (a vehicle owner, an electric charging station operator, and the facility at which they are located) involved with provision of power to or from the resource; and
3) The provision of grid services from an individual or an aggregation of resources.

Through this framework, we define use cases that would allow customer vehicles to be compensated for VGI benefits from a variety of charging arrangements. We identify that four primary regulatory issues must be addressed in order to unlock the benefits of VGI:

1) The Commission should define where the resource is located;
2) The Commission should determine which entities (utilities and/or third-party aggregators) are able to aggregate resources and the point at which it occurs;
3) The Commission and other agencies should define a primacy among different grid benefits; and
4) The utilities need to develop methods to capture and return to customers the value that VGI provides to their distribution infrastructure.

Additional regulatory questions, including ensuring the safe operation of grid-connected PEVs, should be resolved in parallel with the Commission's efforts to address these four issues.

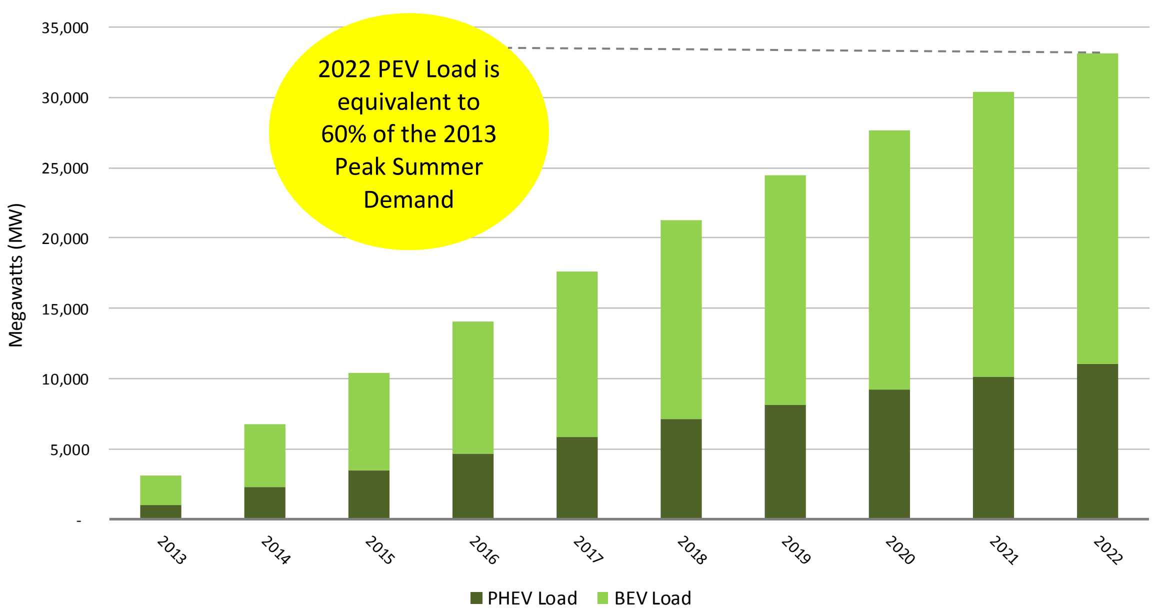
The four categories of VGI use cases should be implemented sequentially, starting with the relatively simple and building in complexity. Each additional category of use cases can build upon the regulatory framework established for prior use cases. In the near term, the Commission should prioritize the enablement of grid services from optimally managing the charging to PEVs to minimize distribution impacts and to enhance the benefits of distributed generation.

2: The VGI Opportunity

In 2012, California Governor Jerry Brown set a state target of getting 1.5 million zero-emission vehicles on California roads by 2025.[1] Achieving the Governor's target with battery electric vehicles (BEV) would represent an additional load of 10,000 MW on the grid. Accounting for plug-in hybrid electric vehicles (PHEV), total load exceeds 30,000 MW, which represents nearly 60% of the summer peak load in 2013 (see Figure 1).[2] If this load were to occur on peak, serving these vehicles would require major grid upgrades and construction of additional generation capacity. Fortunately, we are expecting that most of this load will occur at night due to the financial incentive for drivers to plug-in at night from time of use rates. Typical driving patterns and work schedules further reinforce this, as most cars are parked at home overnight.

PEVs have the capability of providing many more benefits beyond charging at night and storing electricity generated by wind that may not otherwise have been needed.[3] Rather than being viewed as an obstacle for system operators to manage, Vehicle-Grid Integration (VGI), allows these vehicles to be used as a resource that helps us reduce grid operations costs, avoid or defer distribution maintenance and upgrades. VGI may enable the return of these cost savings as a revenue source that improves the value proposition of owning and operating a PEV. Policies and regulations are needed to enable this market so utilities, service operators, and vehicle owners take advantage of these opportunities. Coupling the unique usage attributes of PEVs with new business and operational strategies have the potential to mitigate system impacts resulting from the growth of electrified transportation, and in turn, accelerate PEV adoption and hasten benefits to air quality, reduced GHG emissions, and the development of the industry.

Figure 1: Cumulative statewide expectation for Battery and Plug-in Hybrid Electric Vehicle Capacity. (CEC California Energy Demand 2012-2022 Final Forecast.)



PEVs as Storage Resources

Vehicles have three main characteristics that make them an attractive grid resource: operational flexibility, embedded communications and actuation technology, and low capacity utilization.

Operational Flexibility

A PEV can provide the functionality of both *load* (while its battery is charging) and *generation* (by discharging stored electricity from the battery to the grid). The magnitude of electricity demanded or supplied can be easily controlled and moderated. To exemplify the range of instantaneous load a PEV battery can demand, EVSE and auto manufacturers provide charging options of up to 120 kW (and potentially higher capacity in the future) to accommodate a variety of driver time constraints. Conversely for generation, because PEV batteries supply power to electric motors, they must withstand extreme and instantaneous discharge cycles (to accelerate a vehicle to cruising speeds) and recharge cycles (to recapture energy while slowing it down). For example, a 2013 PEV's battery pack powers a 300 kW electric motor, the largest for the current model year, to accelerate the vehicle to 60 miles per hour in 4.2 seconds.[4] Certain automotive manufacturers are capitalizing upon vehicles' discharge capability to power end uses outside of the vehicle and provide power factor correction for local grids.[5]

Embedded Communications and Actuation Technology

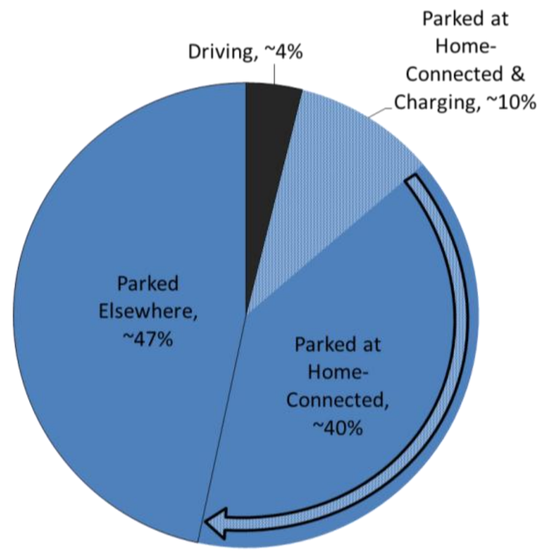
Driven by consumer demand, many automotive manufacturers are incorporating digital and control technologies that improve safety, convenience, and overall driving experience. Technologies used in safety, navigation, and entertainment systems that help increase the "connectivity" of cars to information networks and surrounding infrastructure are also leveraged to improve the ability to manage electric vehicle charging. Many PEVs and certain electric vehicle charging stations are equipped with on-board timers or remotely-controlled switches that are capable of starting, stopping, throttling, or delaying charging. This gives drivers the ability to schedule charging remotely. PG&E and SCE are already exploring how to communicate with PEVs via their Advanced Metering Infrastructure networks to provide demand response.[6]

Low Capacity Utilization

The cost of a battery electric vehicle's energy storage system accounts for 30% to 60% of the manufacturer's suggested retail price[7], its single most expensive component. Compounding this consideration of the battery's expense is the fact that an average vehicle spends only 4% of the day driving (see Figure 2).[8] Energy Division analysis of data from the National Household Travel Survey suggests that the maximum number of cars on the road at any given time is less than 13% (see Figure 3).[9] While vehicles are idle about 96% of the time, an electric vehicle needs to be charging only about 10% of the time, based on the data from the EV Project. This suggests a considerable amount of flexibility for drivers to shift charging to different times of the day to minimize their costs and maximize benefits to the grid.

The use of PEVs as grid resources is contingent upon access to charging infrastructure. Currently, drivers throughout California that participate in the EV Project connect their PEV to residential Level 2 charging equipment for approximately 12 hours per day.[10] However, the PEVs only draw power for approximately 20% of that time (see Figure 4). These figures, which have remained almost constant since the first PEVs began participation in the program, highlight an important relationship between driver behaviors and vehicle energy consumption: drivers will connect their PEVs to an EVSE when they are parked at home, but the energy required for charging is based on their driving needs. Data that San Diego Gas and Electric collected from its PEV Rate Experiment demonstrates this relationship, which found that PEVs' overnight energy consumption is based on the miles driven during the previous day.[11] The ability for a PEV to provide load (and potentially generation), that can be remotely controlled without materially affecting its primary use for mobility demonstrates that there is an opportunity for regulators to work with customers, equipment providers, and grid operators to use electric vehicles as grid resources.

Figure 2: The time PEVs need to charge to meet mobility needs may be shifted throughout the time they are connected at home to accommodate grid operations**.** (NHTS 2009 and EV Project Data.)



Estimated percent of time PEVs spend by location and activity.

The capacity utilization of PEVs may substantially change given emergent trends in the transportation sector.[12] While we do not elaborate upon the total effect of these forces on vehicle-grid integration in great detail here, the key regulatory issues identified in the fourth section of this paper remain threshold issues.

Figure 3: Share of Survey Respondents' vehicles, by location. (National Household Travel Survey 2009.)

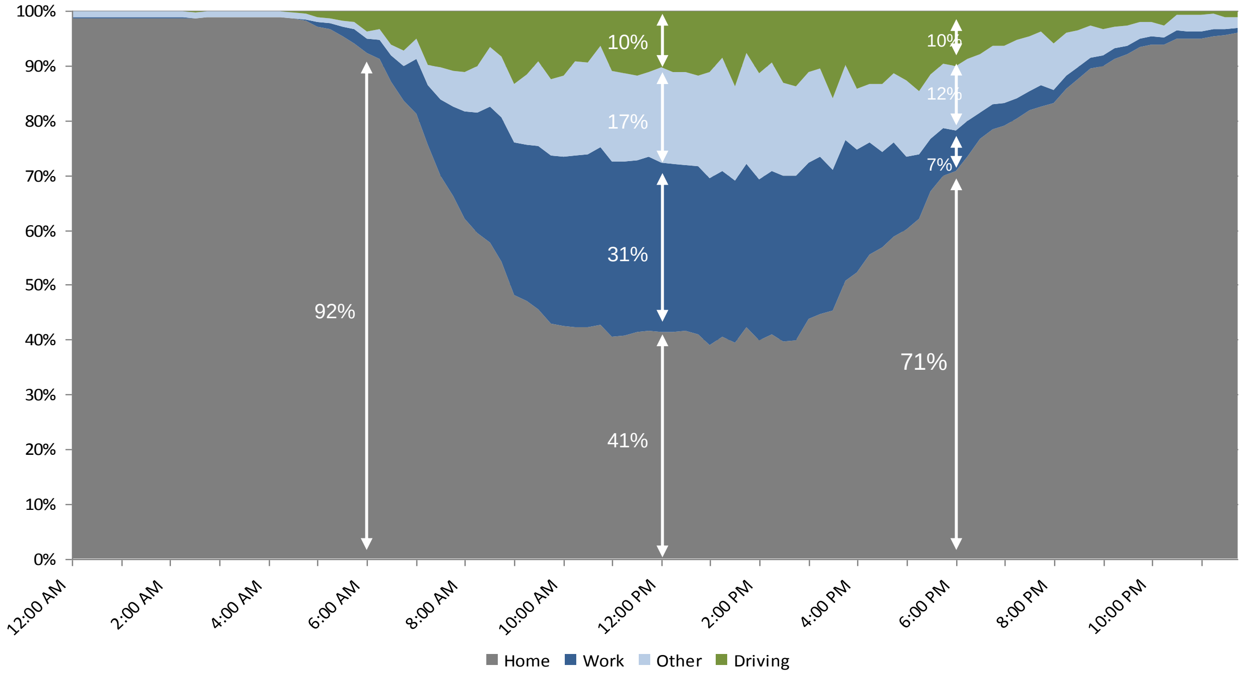
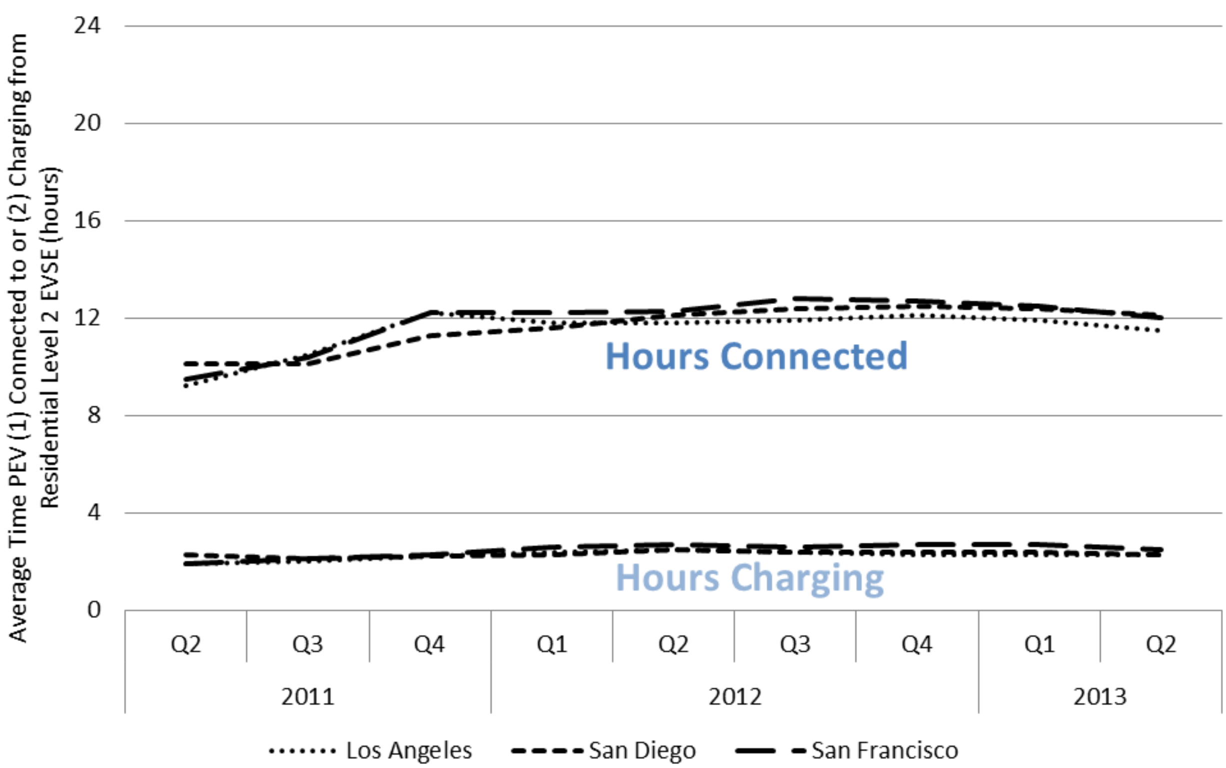


Figure 4: Drivers throughout California have consistently charged at home for only about two of the twelve hours that they are connected to their Level 2 charging stations. (EV Project Data.)



Three Groups of Grid Applications

The usage characteristics of PEVs warrant the application of vehicle batteries to serve the needs of the grid. The grid applications can be grouped based on the grid entity that would receive the benefits: the wholesale market, distribution utility, or the customer. The following descriptions of grid storage applications are based on the Energy Storage Services presented in the DOE/EPRI 2013 Electricity Storage Handbook.[13]

Figure 5: Potential Applications of PEVs as Storage (DOE/EPRI 2013 Electricity Storage Handbook.)

Wholesale Market Services	***Distribution Infrastructure Services***	***Customer-Facing Services***
Frequency Regulation Spinning, Non-Spinning, and Supplemental Reserve Load Following/Ramping Support for Renewables	Distribution Upgrade Deferral Voltage Support	Power Quality Power Reliability Retail Energy Time-Shift Demand Charge Mitigation

<u>Frequency Regulation:</u> Regulation involves managing interchange power flows with other control areas to match scheduled interchange flows and momentary variations in demand within the control area. Regulation is used to moderate changes in grid frequency, which are caused by fluctuations in generation and demand, to maintain them within a range set by the North American Electric Reliability Corporation (NERC) reliability standards. Generation output is increased (or load is curtailed) to provide up regulation when electricity demand exceeds supply. Conversely, generation output is reduced (or load is increased) to provide down regulation when electricity supply exceeds demand. The ability of storage with fast ramp rates to accurately follow an automatic generation control (AGC) has the potential to reduce the wear and tear on other generation.

<u>Spinning, Non-Spinning, and Supplemental Reserve:</u> Reserve capacity is available to be dispatched when normal supply resources are unexpectedly unavailable. Spinning Reserves are synchronized and online, but unloaded, and can respond within 10 minutes to compensate for generation or transmission outages. “Frequency-responsive” spinning reserve can respond within 10 seconds to maintain frequency. Non-Spinning Reserves are not synchronized. Non-spinning generation capacity or curtailable/interruptible loads may be offline but must be able to respond in 10 minutes. Supplemental Reserves can be respond within an hour and provide a back-up for spinning and non-spinning reserves. Generation resources providing reserve capacity must be online and operating at part load. Unlike generation, in most circumstances storage used for reserves does not discharge; it must remain available for discharge as needed.

<u>Load Following/Ramping Support for Renewables:</u> Storage may be used to dampen the variability of a randomly fluctuating load profile or an intermittent renewable energy system, by accommodating a

maximum expected up- and down-ramp rate (usually in MW/minute) and for a given duration of the ramp (potentially hours in length). Storage providing load following may change its output frequently and in response to the balance between supply and load in order to maintain system frequency within the specified range. Storage can accommodate the daily changes in load, upward or downward, by respectively discharging or charging.

Distribution Upgrade Deferral: Storage may be used to delay or avoid investments in new infrastructure (replacing overloaded transformers or re-conductoring distribution lines) that is otherwise necessary to maintain adequate capacity to serve load. The step-wise increase in capacity associated with new infrastructure implies that the measure will, for a large part of its useful life, be underutilized. Storage in this application could extend the usefulness of existing infrastructure. A related application is to use storage to accommodate the system peak.

Voltage Support: Storage may be used to regulate system voltage and so that it is maintained within the specified tolerances for the end-user. Utilities regulate voltage by adjusting tap changers at substations or by switching capacitors to follow load changes to prevent voltage excursions that may be caused by distributed generators or large power loads at the end of radial distribution systems. In this case a storage system can discharge real power to provide voltage support.

Power Quality: Storage can protect customer end-use loads downstream from the storage system from poor power quality, which may take forms including variations in voltage, variations in frequency, low power factor, harmonics, and service interruptions. In this case, the storage system monitors power quality and discharges to smooth the power quality disturbance for durations of seconds to minutes.

Power Reliability: Storage may provide electricity service during times of a utility system outage, either planned or unplanned. If the storage device is permanently interconnected with the grid, this would entail islanding the storage device and customer loads from the utility system, and resynchronizing with the system upon power restoration. PEV storage systems could be designed to serve select loads that can be separated from the customer's electrical infrastructure that is utility-connected, during emergency situations.

Retail Energy Time-Shift: Storage can reduce overall customer electricity costs if they are subject to time-differentiated energy rates ($/kWh) by charging a storage system during low-price times and discharging to serve loads that must be used during high-price times.

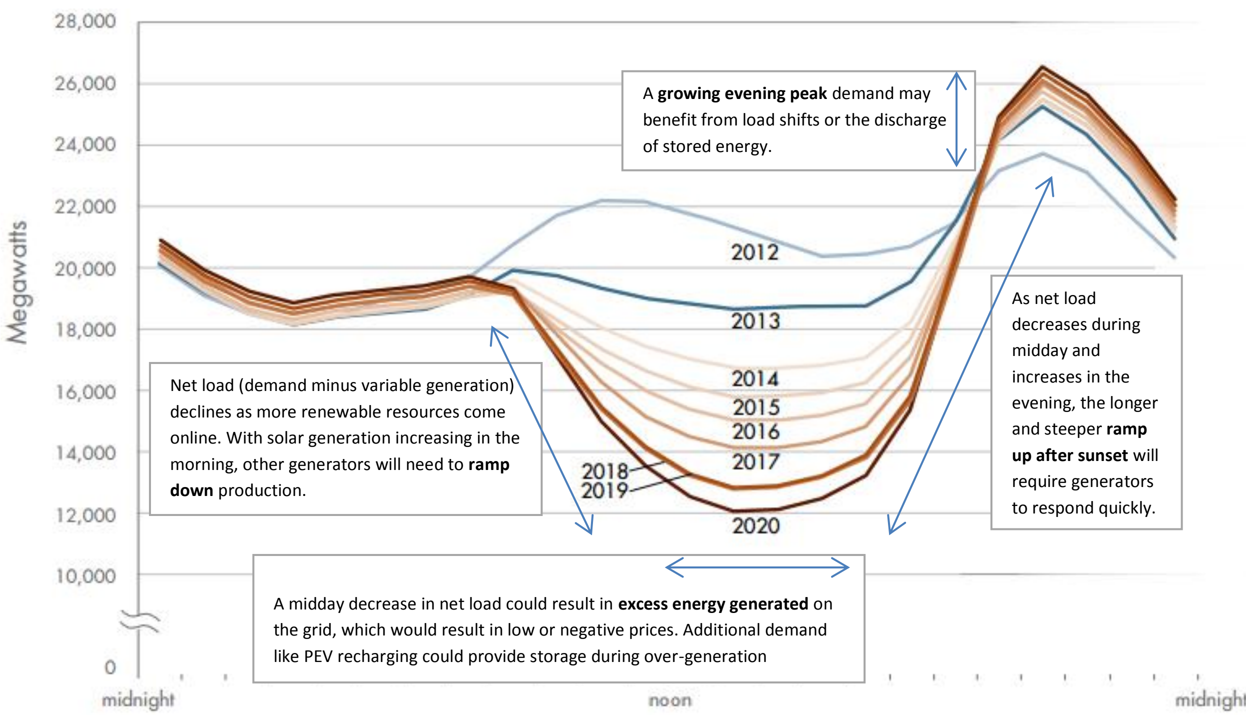
Demand Charge Mitigation: Storage can reduce overall electricity costs if they are subject to a demand charge based on maximum power drawn ($/kW). The avoidance of a charge depends on the applicable timeframes during which a charge would apply, as set forth in the customer's tariff. For example demand charges may apply during a single 15-minute period for a given month, or additionally during certain times of day or months. The amount saved is the difference of the demand cost incurred while charging the system and of the applicable demand cost at the time of discharging the system.

All of these applications will be needed given the substantial anticipated need of the California electricity system for these services in the near future, the use of PEVs to provide each of these storage functions should be explored.

Wholesale Market Needs

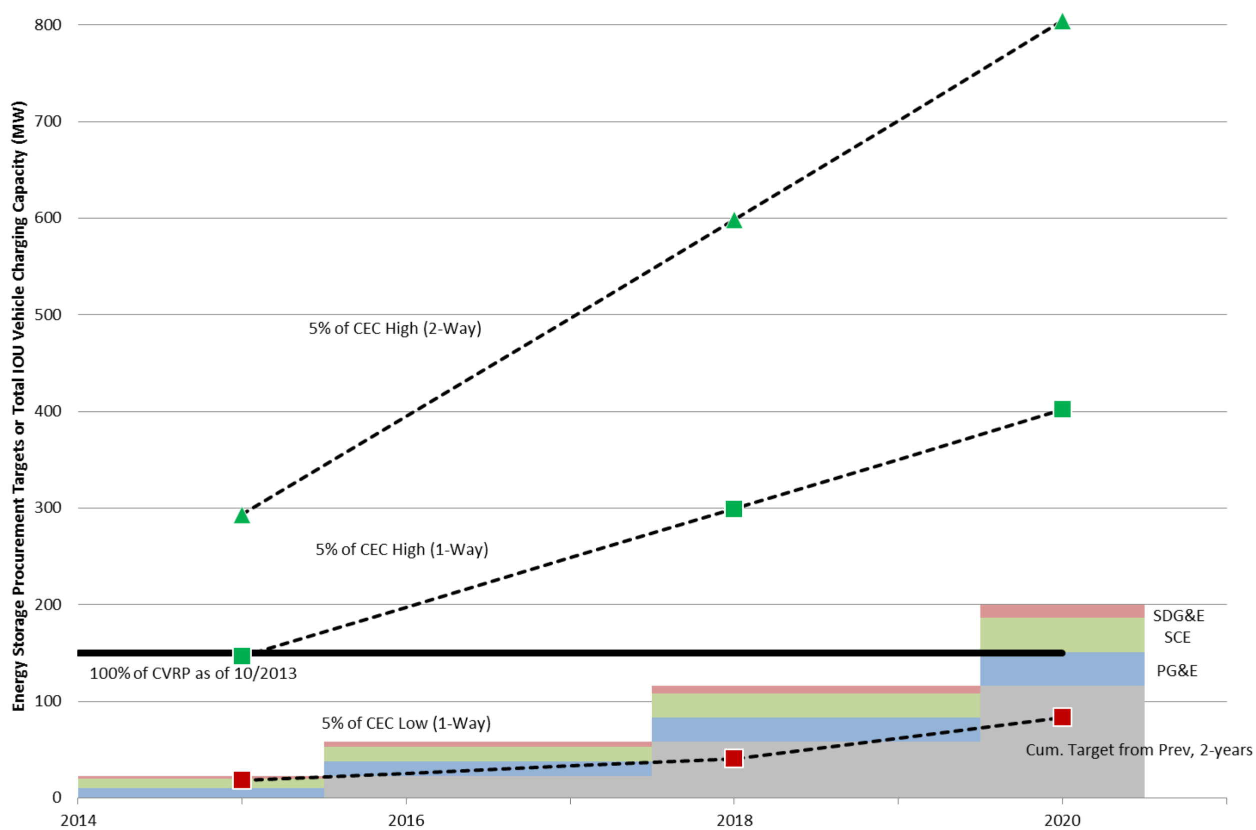
The grid-integration of flexible and potentially underutilized PEV battery storage can complement the state's 2020 greenhouse gas emissions reduction and 2015 environmental goals. As a result of the substantial addition of variable generation to meet the 33% Renewable Portfolio Standard and the retirement or repowering of 16,000 MW of gas-fired generation as a result of the Once-Through Cooling Mandate, the state's electric grid will undergo substantial changes. During the 2013 Resource Adequacy Summit, the Commission[14] and California Independent System Operator (CAISO)[15] stressed the need for resources with flexible capacity[16] to accommodate these changes. By 2020, the grid will need additional demand at certain times to absorb excess intermittent renewable generation, fast-responding flexible resources to accommodate the rapid net load changes, and additional peak generation capacity to accommodate the growing evening peak (see Figure 6). In its Strategic Plan CAISO describes how electric vehicles might serve as a "fast-acting grid-balancing resource" on a grid that has transformed from a centralized "one-way" system to a "two-way decentralized network."[17]

Figure 6: PEVs may serve as fast acting resources to serve certain grid needs for operational flexibility as additional variable renewable energy resources come online. (Adapted from CAISO 2014-2016 Strategic Plan.)



According to Decision 13-10-040, by 2020, the utilities will need to procure 1,325 MW of energy storage. Of the target, 200 MW must be procured from systems that are located behind the customer meter, including those used for electric vehicle charging.[18] Figure 7 below compares IOU customers' PEV charging capacity against the Behind the Meter (BTM) energy storage capacity targets. There may be enough charging capacity from today's fleet of plug-in vehicles within the IOU territories that were purchased with funding from the Clean Vehicle Rebate Program to meet the 2018 116 MW BTM target. This figure also compares the BTM targets to the PEV charging capacity under varying adoption levels and charging configurations.[19] The utilities would need to enroll about 10% of the vehicles in CEC's Low adoption case for PEV charging storage to meet the 2020 targets. In the High adoption case, the utilities would need to enroll only 2.5% of customers to meet the total BTM target assuming one-way (charging only) power flow. If vehicles are equipped with bidirectional power capabilities, fewer customers would be needed to meet the storage procurement target.

Figure 7: The charging capacity from current and expected PEV customers within the IOU service territories represents a substantial portion of the utilities' procurement targets for Customer-sited storage per D.13-10-040. (CEC Demand Forecast and CCSE CVRP Statistics.)



However, these estimates are simply based on charger power capacity and adoption forecasts and do not account for any adjustments necessary to account for the mobility of the battery. Toward these ends, Energy Division is considering methods for quantifying the Net Qualifying Capacity and Effective Flexible Capacity associated with demand response and energy storage systems. These proposed calculations de-rate the amount of capacity that a load serving entity can count toward their System and Local Resource Adequacy and Flexible RA requirements based on the resource's availability, use limitations, and the usefulness of the resource's operations towards meeting system needs.[20] Furthermore, the ability of PEVs to serve specific applications behind the customer meter and the associated costs of doing so need to be proven prior to procurement eligible to meet the target requirements.

If they are able to participate in these initiatives, PEVs may be able to help meet emerging system needs at a lower cost than stand-alone storage or flexible thermal generation. For example, these needs are expected to vary throughout the day. In the mornings, the grid needs flexible load to absorb the increase in solar generation. PEVs that are plugged in and charging at the workplace could absorb this over-generation from solar PV systems, reducing the magnitude of the evening ramp. In the afternoon hours, the grid is expected to need load to curtail in response to solar variability and changes in temperature. PEV charging could respond to grid signals by momentarily curtailing load to avoid negative impacts on the distribution equipment. In the evening, the grid is expected to experience a rapid drop off in solar generation prior to the time that home load increases to the evening peak. PEVs could help provide regulation support, or even serve to reduce peak load through the use of bidirectional DC inverters to deliver energy to the grid to reduce peak demand. At night, the grid will be vulnerable to spikes in wind generation. Nighttime PEV charging could be signaled to increase its charge rate to mitigate changes in system voltage.

In the longer-term, PEVs will assist the state in meeting federal standards for local air quality by 2032 and should contribute to zero emissions load balancing to ensure grid reliability as the electric system evolves to achieve an 80% reduction in greenhouse gas emissions from 1990 levels by 2050.[21] The California Air Resources Board (CARB) Climate Change Scoping Plan recommends that the State continue to support ZEVs through regulation, vehicle incentives, investments in vehicle charging infrastructure, and policies and planning efforts to ensure that value is returned to customers and that ZEVs integrate effectively into the electricity grid, communities, and daily lives.[22]

Studies analyzing mitigation pathways to achieve the GHG goal conclude that it is essential to decarbonize energy sources and then electrify additional energy end uses, such as transportation. Because decarbonized electricity generation will consist largely of intermittent renewable power, however, increased reliance on those sources may require an increase in flexible fossil generation to balance supply and demand. [23] Battery storage could provide such load balancing with zero emissions. Because large quantities of battery storage will be deployed in electric vehicles as they gain market share, it is reasonable to look for ways for PEVs to provide that service. Between 2040 and 2050, electricity demanded from PEV recharging could range between 14-29% of 2008 total system electricity demand and provide 500-1000 GWh of battery storage.[24] Another study noted that smart charging the electric vehicles could improve load factors and obviate additional electric capacity to reduce costs and the need to coordinate deployment to avoid emissions from switching to fuels before the grid is decarbonized.[25]

Distribution Grid Needs

Helping customers minimize the impacts of their PEVs on the distribution grid should be the first step in promoting vehicle-grid integration, as it will reduce the upgrade costs that may ultimately be borne by general ratepayers and PEV users. The integration needed for PEVs to act as system resources begins at their interconnection at the distribution level. D.11-07-029 in the Alternative Fueled Vehicles Rulemaking (R.09-08-009) initiated several efforts that establish the foundation of our vehicle-grid integration vision including the need to research and track distribution upgrade costs associated with PEV load, utility notification policy, and the development of a PEV submetering protocol.

The utilities considered that the electrical infrastructure in residential neighborhoods was relatively more vulnerable to the unplanned, larger loads of PEVs than the infrastructure in areas planned for commercial and industrial customers. They reasoned that C&I customers had higher capacity infrastructure but also tended to engage the utility directly and early on to plan for changes in infrastructure.[26] The Load Research and Cost Studies completed pursuant to that decision found that under current levels of adoption, PEVs have not yet added sufficient new load to require substantial improvements to residential distribution infrastructure—0.4% of the IOUs' infrastructure checks required a distribution upgrade and only 0.1% of them exceeded the allowance permitted under Electric Rules 15 and 16. However, the utilities caution that residential charging behaviors among early adopters are likely different than that of mass market PEV drivers.[27] As PEV penetration increases, it becomes more likely that distribution upgrades will be needed.

The point at which distribution infrastructure needs upgrading depends on (among other things) overall age and utilization, peak loading, and, increasingly, the impacts of distributed generators on voltage regulation and frequency control. Widespread electrification highlights the import of properly incentivizing or coordinating the use of PEV charging and discharging activity to reduce negative impacts. PEVs may be particularly productive in this manner if they, like DG, are located at the "right place at the right time."[28] For example, preventing the overloading of distribution transformer capacity and thereby prolonging the life of existing infrastructure can minimize system upgrade costs. Fully utilizing limited capacity by staggering vehicle charging occurring on a given feeder can help minimize impacts.

Customer Needs

Used as a grid resource, PEVs can help customers manage their demand charges and avoid high cost charging times. By managing the time of their charging, customers can avoid charging during peak rate times and they can avoid charging during times that contribute to demand charges.

These benefits apply differently depending on the type of customer and the rate tariff that they are on. Most residential customers are currently on tiered rates, which do not have different rates during different times of the day. Residential customers also have a range of circumstances that impact their rate schedule and their energy costs: from households in detached single family homes to those in multi-dwelling units; from engaged customers that pursue Net Energy Metering with separatelymetered PEV time-of use rates to low energy users that are economically incented to remain on tiered rates even after including their PEV energy consumption. Fleet operators vary substantially among utility "classes" (institutional, small/medium business, large commercial and industrial), but also among the types of vehicles they use and their usage characteristics. For example, the electrical service needs of a corporate delivery hub deploying medium duty trucks throughout a region daily is far different than a small local government using light duty vehicles for their operations. Many commercial customers and fleet operators face demand charges, but the profile of their usage can vary substantially, depending on their load profile.

In D.11-07-029, the Commission discussed the consideration of costs incurred from electric vehicles and the applicability of electric rates to PEV customers. It stated generally that rate design should reflect any additional distribution system costs that result from peak Electric Vehicle charging that impose demands on any distribution-constrained facilities.[29] The Commission suggested that rate design would be revisited in 2013 once information on load profiles, customer behavioral responses to price signals, and the costs and benefits of charging were available. The Commission ordered the utilities to quantify the "system costs and societal benefits" in their revision of rates in 2013.[30]

Rates are currently designed to maintain the principle that customers should bear the system costs for which they are responsible. Both residential and non-residential PEV customers have cautioned the Commission about enforcing this principle to the extent that doing so could slow overall incentives for electrification. So far the Commission has provided temporary solutions as to not overburden residential customers and discourage adoption, but it has not done so for non-residential customers generally.[31] However, given a better understanding of customer economic concerns and behaviors, we highlight the finding of D.11-07-029 that rate design should account for the costs and benefits of PEV charging. It is important that rates and the distribution planning processes capture the entire range of costs and benefits of PEV charging, particularly given the clear opportunities for PEVs to provide electric system benefits in addition to environmental benefits.

For the state to reach its air quality and climate change goals, it is imperative that vehicles in each market segment[32] have adequate and economic options for charging infrastructure to store the energy needed to meet their travel requirements within their scheduling constraints —whether they use their own dedicated equipment or they use other options accessible to them.

Valuing Vehicle-Grid Integration

VGI can represent a potential revenue stream to customers. Several studies have estimated the value of integrating vehicle charging and discharging requirements with customer facility and system needs. We cite findings from select studies as illustrative examples.

- A government fleet of PEVs in Southern California providing regulation up and regulation down to the CAISO markets may yield total revenue of $100/month-vehicle.[33]
- An institutional fleet of PHEVs in Boston providing discharging energy to a building at peak times could mitigate demand charges and result in savings of $100/month-vehicle.[34]

- A BEV charging at 6.6 kW in California providing demand response to its utility may provide savings worth approximately $60 /year-vehicle, depending on the time that it is charging.[35]

While individually these value streams may appear small, depending on vehicle pricing and financing options, it is possible that the value could significantly impact the total cost of ownership for residential or fleet owners and influence adoption decisions.

Pursuant to D.11-07-029, the value of Vehicle Grid Integration should be assessed for costs and benefits they afford to the an electric system and society generally. Similar to a study that would compare the ratepayer and social impacts of Net Energy Metering, evaluations of Vehicle Grid Integration should encompass the entire range of costs and benefits, which may include:[36]

<u>Benefits</u>

- Avoided energy costs
- Avoided marginal system line losses
- Net Qualifying Capacity and Effective Flexible Capacity
- Transmission and Distribution Upgrade Deferral
- Ancillary Services
- Fuel Price Hedge
- Market Price Response
- Reliability and Resiliency
- Avoided Environmental Compliance Costs
- Societal and Overall Economic Benefits

<u>Costs</u>

- Utility Costs
- Administrative Costs
- Interconnection Costs, borne by the Utility or General Ratepayers
- Vehicle Integration Costs, at given levels of vehicle penetration.

The utilities have not yet explored in detail the impact of vehicle-grid integration on the costs of operating and maintaining the electric system. An evaluation framework that encompasses these, and potentially other costs and benefits will be needed.

Limitations to Vehicle Storage Resources

The opportunity of VGI is partially complicated by two features of plug-in electric vehicles: their size and the fact that their primary purpose is for personal transportation.

<u>Size of Vehicle Load</u>

The power load of an individual plug-in electric vehicle can vary substantially depending on the charging technology employed. Load is largely determined by the amount of energy that is needed to fulfill the driver's transportation needs, and the time available for recharging. For example, the average load[37] drawn during charging events in the EV Project ranged from 3.6 kW at residential, private non-residential, and public Level 2 AC EVSE to 19.3 kW at public DC Fast Charging stations. Many newer PEVs have optional 6.6 kW onboard chargers. Electrified buses and medium or heavy duty vehicles may also have higher charging requirements.

The size of the vehicle load has been a challenge in the Commission's efforts to integrate PEVs into the grid, particularly since they can be "large" when compare with the distribution system. In D.11-07-029 the Commission allowed distribution system upgrade costs associated with residential PEV charging in excess of the residential allowance in Rules 15 and 16 to be treated as common facility costs. While the costs associated with this policy were de minimis, in D.13-06-014 the Commission stated its concern that ending the common treatment would impact overall PEV adoption.[38] Absent the common treatment, a residential customer could arbitrarily be assigned the cost of a distribution system upgrade if the PEV was deemed to be the cause of such an upgrade. This aspect of grid integration is further complicated by the lack of consensus on the exact amount of load associated with "basic" residential Electric Vehicle charging, given the availability of higher-power chargers during the early stages of the market.

For when the Commission determines long term policies related to the treatment of residential PEV load (and potentially, the magnitude of an allowed charging load), it is important to consider the converse issue of PEVs being "small" when compared to local areas and balancing area-wide electrical systems.

<u>Primary Use for Personal Transportation</u>

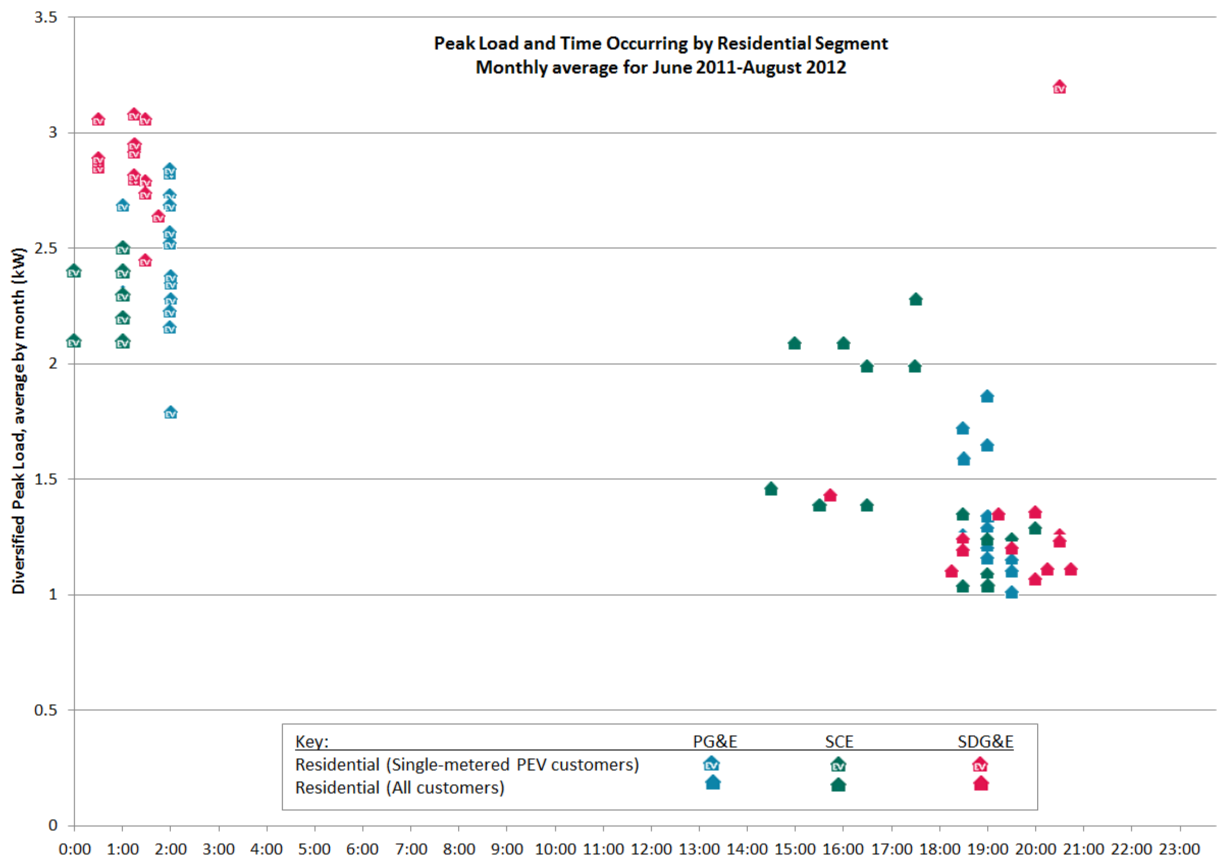
The VGI opportunity must be coordinated with the fact that the primary end use of a PEV is for personal mobility. Unlike distributed generation assets, PEVs are only temporarily interconnected to the electric grid.[39] The impermanence of a PEV's grid connection and the magnitude of its load suggest the need for greater coordination between regulators, utilities, and customers in distribution planning and operations for vehicles to participate as grid assets. Fortunately, the Commission has already taken steps in this regard. As a result of the utilities' research and other initiatives, we are beginning to learn about what, when, and where, and how much energy PEVs need. This data will help the Commission understand the availability of PEVs as storage resources.

In D.11-07-029 the Commission stated a priority to charge PEVs during the off-peak time periods and directed the utilities to research the charging behaviors of their customers.[40] While the following results are representative of early market adoption, they are promising from the perspective of demand forecasting and management. Utility load data has demonstrated that the PEV charging is generally occurring during off-peak periods. For example, PEV customers enrolled under the "whole house" PEV tariffs, which use a single meter to measure both PEV and residential load, demand the most power between midnight and 2 AM. Conversely, the average residential customer peak demand occurs during the evening. The time diversity of these peaks may benefit the longevity of distribution infrastructure (see Figure 8[41]). This behavior can enabled by using technologies, like timers or staggered direct load control, to reduce the barriers to off-peak charging.[42] It is important to emphasize that off-peak charging behaviors persist more strongly if energy prices are sufficiently differentiated between the time of use periods.[43]

PEV and EVSE utilization data give us crucial insights as the utility assumes the key role of their customers' transportation fuel provider and plans for the transient nature of these loads. 68-79% of all charging events occur at home.[44] While there is some variation across the utility territories, charging a PEV at home requires approximately 250 kWh/month.[45] As described earlier, residential charging varies substantially during the week: PEVs use around 28% more energy Tuesday through Saturday than during Sunday and Monday.[46] Continued, careful load research on travel needs and infrastructure utilization will be crucial for the Commission to improve the design of just and reasonable PEV tariffs and programs to encourage electrification.

This research will be particularly important to understand how the potential benefits of vehicle-grid integration vary with the types of charging infrastructure deployed and the types of vehicle (battery versus plug-in hybrid) adopted. For example, the 20% ratio of time charging to time connected observed in residential Level 2 EVSE would enable substantially different VGI benefits compared to those that might be available under DC Fast Charging.[47] In addition, the EVSE installations and energy required under a high-electrification scenario will be different given the share of PHEVs and BEVs. Today, PHEVs are charging more often than BEVs, presumably to maximize their electric range.[48]

Figure 8: Throughout the state, peak demand for customers enrolled in single-metered PEV TOU rates, which apply to both home and vehicle loads, occurs between Midnight and 2AM. Off-peak charging provides a diversity benefit since general residential customers' peak demand occurs in the evening. (Joint IOU Final Load Research Report.)



3: A Framework for Vehicle-Grid Integration

The Commission is directed by the ZEV Action Plan to address regulatory barriers to vehicle-grid integration. Energy Division proposes that there are eight types of interactions between electric vehicles and the grid that are framed by three dimensions: (1) the direction of power flow at the point of the PEV's interconnection; (2) the coordination the objectives of actors that control devices necessary to complete a transaction for grid services; and (3) the number of resources included within a transaction for grid services.

Direction of Power Flow

Whether the vehicle is a controllable load or a storage device that provides stored energy to the grid is the most significant factor influencing the size of the resource. Unidirectional power flow into the battery (also known as "V1G") can start, stop, and vary its charging level up and down, but doesn't discharge the battery to the grid. Meeting recharging needs in coordination with time-of-use (TOU) pricing or to the constraints of the system, can be referred to as "Smart-," "Managed-," or "Controlled-" charging. Bidirectional power flow in and out of the battery (also known as "Vehicle-to-Grid" or "V2G") can similarly fluctuate charging but also decrease the state of charge by discharging energy to the grid.

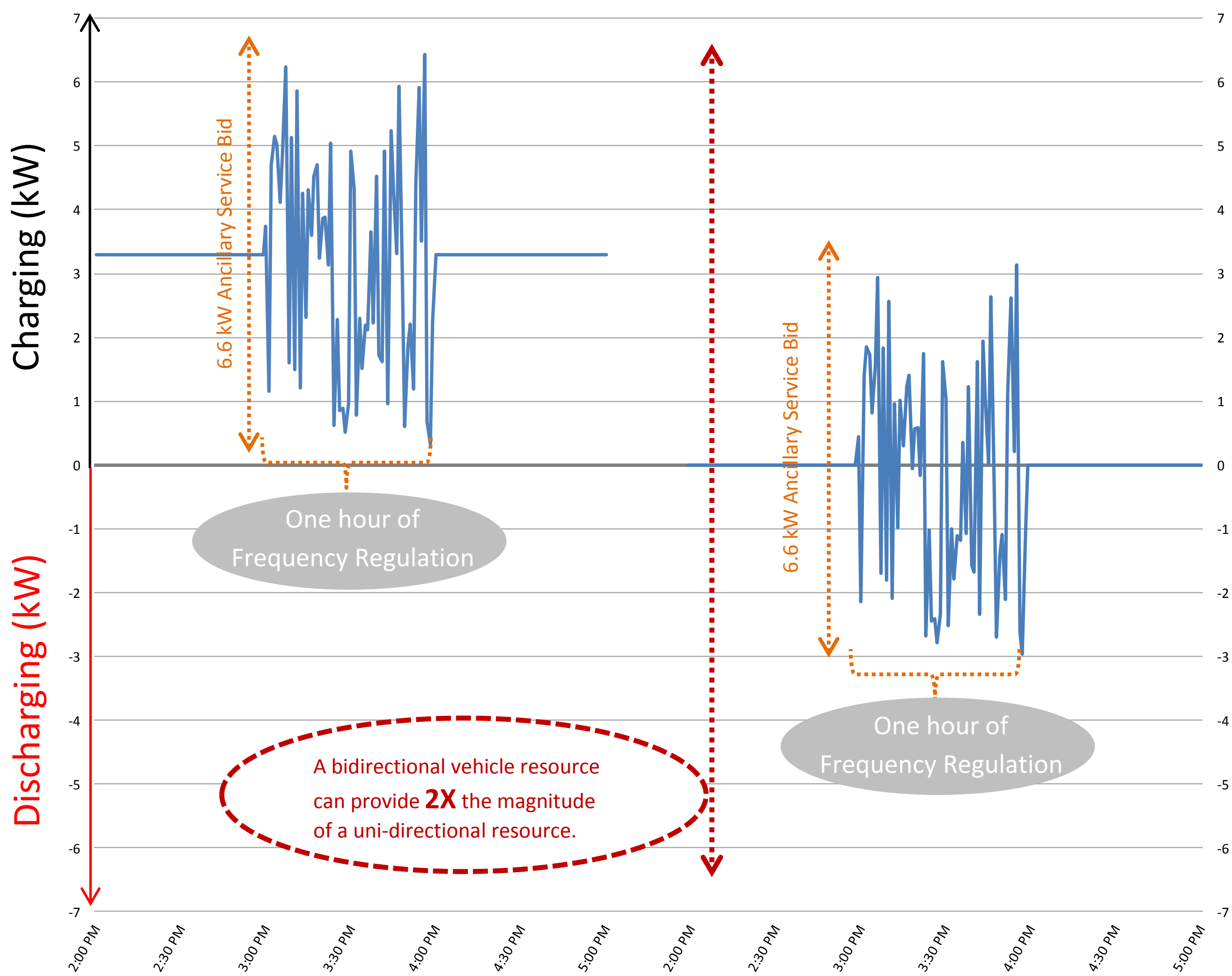
V1G can provide many of the same set of services to the grid as V2G. By varying its charge level, controlled charging can provide any ancillary service, including frequency regulation. Figure 9 below illustrates how a V1G and a V2G resource can both provide the same frequency regulation service, however they differ in the magnitude and duration of the service that they can provide.

As a controllable load, V1G can likely take advantage of a the existing regulatory framework like that created for Demand Response, which already established the requirements necessary to aggregate and integrate a controllable load dispersed at many sites across a geographic area. Unlike generating resources, using V1G does not require interconnection processes to qualify as a grid resource. V1G uses the distribution system to receive power, but does not incur costs associated with accommodating the backfeed of electricity associated with V2G. This eliminates the need to compensate the utility for the use of its infrastructure when providing V1G services to the wholesale market. V1G does not incur round-trip efficiency losses associated with V2G because it does not discharge energy.

Bidirectional power flow introduces regulatory complexity beyond that of a controllable load. As a bi-directional storage resource, the grid operator must evaluate two options: whether electricity discharged from the battery (1) is used entirely on-site or (2) back-feeds to the grid beyond the facility's primary meter. In the first case, the PEV serves load at the customer site, and can be referred to "Vehicle-to-Building" or "Vehicle-to-Home." Here, the utility must be certain that the vehicle cannot actually discharge electricity onto the grid and the storage can be considered a load modifier. In the second case, the PEV may potentially serve the entirety of a customer's load, particularly if coupled with distributed generation. The amount of customer load served by the vehicle may vary over timescales (instantaneously to annually), causing challenges in determining the adequacy of infrastructure needed to serve the customer reliably. Behind-the-meter grid resources are required to have an interconnection agreement subject to Rule 21, if the resource faces the utility, or a Wholesale Distribution Tariff (WDAT), if the grid faces the wholesale market.[49] These interconnection rules can require that the resource pay interconnection fees, distribution compensation, and technical grid studies. In grid constrained areas, a bi-directional resource may face additional interconnection challenges.

V2G also introduces technical concerns that impact vehicle design and warranty structure. PEV warranties are currently not structured to allow battery discharge onto the grid. V2G may void the battery warranty, depending on the terms of the warranty structure and the design of the battery.[50] To support the backflow of electricity, a vehicle battery will need an inverter, either on-board or stationary, to support the conversion of the battery power from DC to AC electricity. This process will result in power losses, which reduce the value of the grid service.

Figure 9: An identical frequency regulation signal can be met by either a V1G resource (L) or a V2G resource (R). However, the V2G can provide services at twice the magnitude and for a greater duration than the V1G resource.



Despite its complexity, bidirectional capabilities avail a larger capacity and longer duration resource than controlled charging. V1G can only provide grid value during the times that the vehicle is charging. Using EV Project data from above, for a typical California residential PEV customer, controlled charging will amount to about 2 hours per day. A vehicle that can discharge its battery to the grid can provide grid services whenever it is plugged-in and able to communicate with the grid. In addition to increasing capacity factor, V2G allows a vehicle to provide twice the magnitude of service as V1G, as shown in Figure 9. It can drop from its maximum charge rate to the maximum discharge rate, doubling the output of a V1G resource.

Coordination of Actor Objectives in the PEV Value Chain

The complexity of a VGI transaction increases substantially when the number of entities involved increases. A given VGI transaction could involve different actors managing each of the following elements: (1) the vehicle, (2) the charging station, and (3) the facility. Each of the actors that claim ownership or control of these parts of the PEV value chain may have different objectives and be affected by each other's actions in vehicle-grid integration.

This raises a "principal–agent problem" observed elsewhere in energy policy (e.g., residential adoption of efficiency measures in a rental property). For VGI, this problem is compounded by the ambiguity of which actor is the principal (the entity with the legal capacity to execute VGI) and the agent (the entity that carries out or supports the actions of the principal).

"Unified Actors" refers to the case where each of these elements is managed by a single entity or multiple entities are able to coordinate vehicle charging in a manner that maintains positive value for all entities. A VGI transaction in this context is relatively simple to coordinate. A single entity would align the actions of each component of the transaction and can collect all the benefits. Costs imposed on a particular element would not necessarily prevent the transaction, because those costs could be weighed against and offset by benefits to other elements, resulting in net benefits that would all accrue to the same entity or that could be fairly distributed among entities.

Figure 10: Unified Actor Objectives

Corporate PEV: Understands travel departure and energy demands with scheduling system.
Corporate Charging Station: Wants to fluctuate during the afternoon to minimize costs
Employer Facility: Wants to curtail demand during the afternoon to mitigate demand charge

"Fragmented Actors" refers to other charging situations, in which all or a subset of these elements are owned or controlled by separate entities. This may occasionally result in charging that results in negative value to one of the actors. For example in workplace charging, the facility account holder, the operator of a networked charging station, and the vehicle may be owned and controlled by different entities. In this case, it is not immediately clear which entity will make decisions about how the VGI resource is used. The actors may have multiple and potentially divergent objectives: to do what is economically optimal for the grid system-wide, the facility's overall costs, or the vehicle's mobility. For example, the charging station may want to provide frequency regulation signals in the afternoon, while a vehicle owner needs energy to return home. Simultaneously, the facility may want to reduce its demand charge.

Figure 11: Fragmented Actor Objectives

Employee PEV: Wants a full battery to return home from work.
Network Charging Station: Wants to fluctuate during the afternoon to minimize costs.
Employer Facility: Wants to curtail demand during the afternoon to mitigate demand charge

In this case, co-optimizing the actions of multiple entities subject to potentially conflicting constraints might result in net costs to one entity. These actors may be able to settle this transaction on their own. However, if they cannot, it is possible that this barrier will significantly hinder the realization of the potential benefits of VGI to only cases with Unified Actors. Fragmented ownership cases can be better enabled by clearly defining which component in the charging arrangement serves as the grid "resource," an issue described in Section 3.

Geographic Resource Aggregation

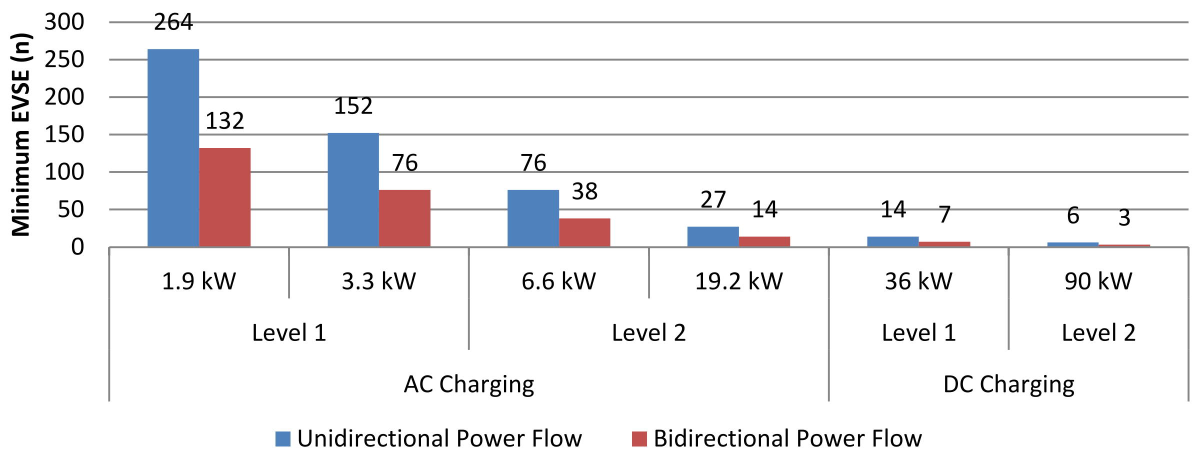
The third characteristic of vehicle-grid integration is whether the VGI benefits are provided by an individual resource or an aggregation of resources. Geographic aggregation of vehicles as a 'virtual' grid resource would provide several advantages over a single vehicle location as a resource.

The term 'aggregation' here is used to refer to a group of resources that are geographically dispersed, but are scheduled and dispatched as a single resource. While it is possible for multiple vehicles charging at a single location to serve as a resource, this type of aggregation does not face significant regulatory challenges. From the grid's perspective, these vehicles are already behind a single primary utility meter, so it can be managed as a single grid resource, regardless of how many individual vehicles are at that the location and regardless of how the resource is defined by CAISO or CPUC.

Geographic aggregation increases the opportunity to get VGI benefits. Aggregation across multiple grid locations would make it easier for individual vehicles to participate in the wholesale market because reaching the wholesale market minimum resource size (500 kW) requires using multiple light-duty vehicles as a resource.[51] Most vehicle chargers are under 10 kW, requiring that many vehicles be combined into one 'virtual resource' (see

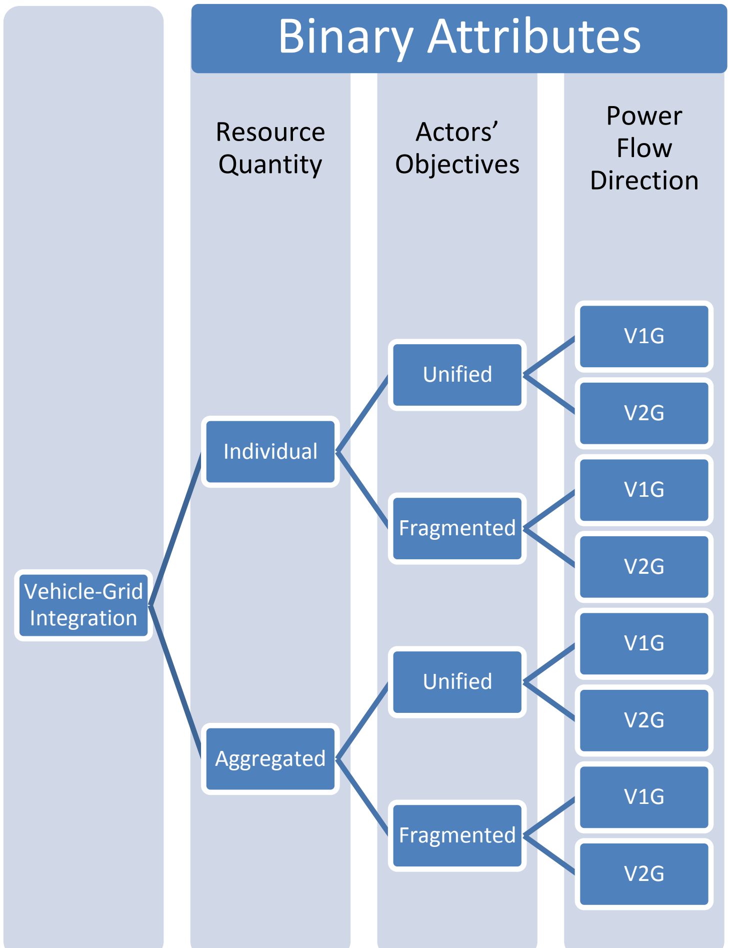
Figure **12**).[52] In addition to its size constraint, the availability of vehicles to provide services is also limited, based on a given vehicle's state of battery charge and whether it is interconnected with the grid. Aggregation can allow a given vehicle more opportunities to serve the grid despite this size and time constraints. Conceivably, an aggregator would diversify the pool of vehicles counted within its resource by taking into consideration the probability of its location and estimated state of charge. Doing so would increase its ability bid and receive awards, and reliably serve dispatches. It could also expand the duration and magnitude of the 'virtual resource.'

Figure 12: Minimum number of EVSEs of a given charge capacity needed to satisfy the 500 kW minimum capacity requirement for a Non-Generating Resource**.** (CAISO NGR and SAE.)

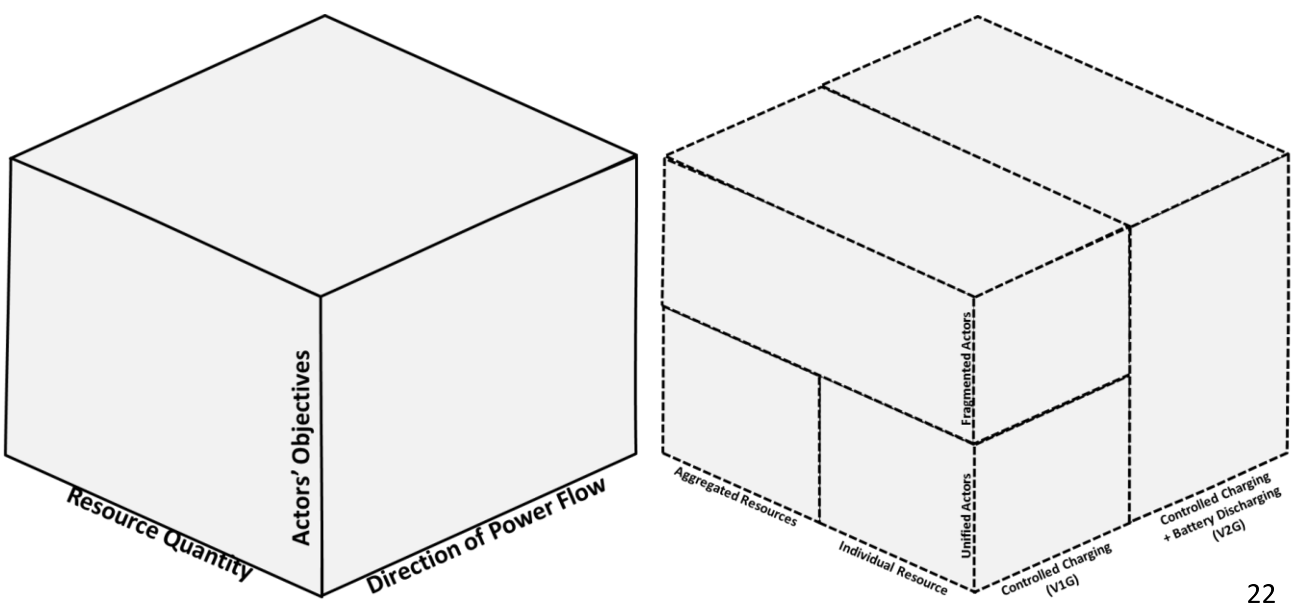


Dividing a single resource across multiple locations complicates providing distribution level benefits. A geographically aggregated resource would be spread across a range of distribution locations, which limits a utilities' ability to manage that resource to benefit the distribution system. For example, if an aggregated resource is spread out across different substation areas, the utility would need some level of oversight over this resource to ensure reliability throughout all affected parts of its distribution system. This could be addressed by providing utility congestion signals to third party aggregators, or by allowing the utility to play a role in resource aggregation.

Figure 13: The Vehicle-Grid Integration Framework



The VGI Framework is defined by three attributes, each with two potential options: whether the benefit to the grid is provided by an individual or aggregation of resources; the alignment of the objectives of actors involved with the PEV charging, and the direction of the power flow (one- or two-way) from the resource. Eight use cases exist given the combination of the three attributes. However, as discussed below, understanding the regulatory considerations with each "dimension" provides a path toward implementation. With this in mind, the framework is depicted as a cube that bounds the use cases. Starting simply, and sequentially answering each regulatory question allows us to unlock the range of benefits from all VGI use cases.



4. Key Regulatory Questions

The four defining regulatory issues are: 1) identifying the resource and determining at which point grid services are measured; 2) determining what entities may aggregate the resources and interact with the wholesale markets; 3) determining how to capture distribution system benefits, monetize those benefits, and distribute them to the various actors; and 4) determining the primacy among the potential VGI activities.

How and where is the resource defined?

A primary regulatory question facing VGI is defining where the resource is located. This question will determine who can claim ownership of the resource, how the resource is measured, and how communication is managed. This challenge is particularly important to PEVs because they are temporarily interconnected to, and move to different points throughout the grid, adding a layer of complexity that does not exist for other grid resources. It is not clear that regulators must act on this question, as the market may be able to address this issue on its own, once other barriers are addressed.

Aside from performance requirements, the CAISO definitions of "Load" and "Non-Generating Resource"[53] do not specifically prescribe what comprises the "resource." A distinction may be important for VGI because the provision of a grid service from a vehicle to its intended recipient involves multiple essential elements for charging (or discharging) the battery: the vehicle, the charging station, the host facility, and (in some cases) the aggregator. Any one of these end-use devices involved with charging could serve as the "resource." Furthermore, these elements might be controlled by different entities. There are advantages and disadvantages to VGI associated with each varied location and the entities involved. How a PEV resource is defined will impact what business models can develop around the technology. Defining the resource also determines who is responsible for complying with regulatory requirements and CAISO/utility interconnection requirements. Resources could be defined at a(n):

- ***<u>Vehicle:</u>*** Defining the resource as the PEV itself is the most elemental point at which the CAISO would measure changes in load and energy. At this point, measurement would be closest to the charger (or inverter if providing bi-directional energy) and the user that controls the flow of energy into the vehicle battery. This would likely require that the vehicle have a meter to measure transactions. CAISO has previously stated a preference for measuring the performance as close as possible to the device, and defining the vehicle as the resource would satisfy that preference. Electric vehicles could be distinguished from other resources if they qualified under the Energy Action Plan as energy efficiency or demand reduction measures. Since the vehicle would move to different locations, however, this option would either require a customer account that could "roam" with the vehicle or require vehicle owners to settle transactions with the facility owner at which they are located.
- ***<u>Charging Station:</u>*** If the resource were defined at the charging station, some of the settlement complexity would be reduced, since the charging station is at a fixed location on

a fixed primary meter. Double counting of energy loads would still need to be resolved between the facility and the charging station. This location also provides advantages for distinguishing PEV load as a 'preferred resource,' similar to defining the resource as the vehicle itself. The charging stations currently available on the market do not know the battery state of charge, which would reduce their effectiveness at providing grid services unless they have an agreement with automakers to access that data.

- ***Facility:*** Rather than allowing vehicles to specifically provide grid services, vehicle storage could be rolled up as part of the grid services from the entire facility load. This arrangement would eliminate double counting problems, since facilities could only bid their load in once. To enable this, the facility would need to work with charge service providers and vehicle drivers to coordinate accessing the vehicle for services. Currently, many facilities (particularly workplaces) do not have a relationship with the PEV driver.
- ***Aggregation of Resources:*** A fourth option is to define the resource at the aggregator level. In this case, the resource is 'virtual,' made up of numerous, perhaps geographically dispersed grid resources. CAISO already has rules that accommodate this definition, so long as the aggregation of resources is located in one Sub-Load Aggregation Point (sub-LAP). This approach presents some challenges to integrating utility benefits and would require a CAISO-approved metering approach to aggregate the metering results.

It may also be possible to let the market decide this issue. To do so, regulators and grid operators could simply enable each option as a potential grid resource. This has the advantage of allowing market participants to determine how to best enable VGI functionality. Entities would only participate if they appropriately compensated, forcing an equitable solution. However, the uncertainty in this approach could yield a stalemate between parties, delaying any meaningful progress. Or it could require that regulators address a series of individual scenarios where the objectives of the different actors that control the facility, the charging station, and/or the vehicle are conflicting – producing a de facto regulatory schema despite our intentions.

Regardless of the approach, CAISO and CPUC should coordinate their approach to resource definition. To meet CAISO market participation requirements, the controlling entity would be responsible for signing a Participating Generator Agreement (PGA), Participating Load Agreement (PLA), Meter Service Agreement (MSA), Wholesale Distribution Access Tariff (WDAT), service contracts and potentially other agreements in order to respond to signals from CAISO, making bids, and metering the performance of the resource. The location of the resource also impacts where the metering and communication must be located to settle wholesale market transactions.

What is the utility role in aggregating resources?

While vehicles are small relative to the typical wholesale market resource, they must be aggregated to respond to wholesale market signals. For Non-Generating Resources, a grid resource must be a minimum of 500 kW to be eligible to participate in the wholesale market. CAISO rules permit an aggregated resource to be made up of geographically-dispersed resources so long as they are in the same Sub-LAP, the smallest geographic area from the perspective of the wholesale market.

It is unclear what role the utility will play in relationship to aggregators. As an aggregator, the utility could help align distribution needs with wholesale market participation, but could limit business innovation in this space. There are four potential models for the utility role related to aggregation: (1) utility as the sole aggregator, (2) utility as meta-aggregator, (3) competitive aggregation market without utility participation, and (4) a hybrid approach where utilities and non-regulated firms can both serve as aggregators.

Utility as the Sole Aggregator.

Under this scenario, the utility would be the sole entity responsible for aggregating vehicles. The utility would be responsible for enrolling customers and the program would provide incentives for customers to allow the utility to control its charging or discharging. The utility would use this control similar to scheduling coordinator rights to provide grid services to the wholesale market, while meeting the local needs of its service territory.

If the utility has control over these resources, it would have full visibility into how these resources could be used to best manage the limited capacity on the distribution system. For example, if there are four electric vehicles in a neighborhood that are all connected to the same transformer, the utility could ensure that these vehicles never overload the neighborhood circuit and that they are strategically charged to prolong the life of the existing transformer. These distribution cost savings could be passed on to the customer.

This approach limits opportunities to innovate with new business models. This business model would call on the utility to have detailed knowledge of customers' travel behaviors, something that customers may be reluctant to provide to a utility. Customer preferences related to controlled charging are unknown. Utilities have little experience understanding customer transportation and it is not clear how they would develop the expertise to manage this experience.

Additionally, by providing utilities with a monopoly over this market, it is not clear that the utilities will have the right incentive to provide customers with all of the benefits they are creating. The Commission would need a way to measure performance of managing electric transportation needs and incentivize the utility to provide services. Furthermore, the utilities' ability to earn a return on investment upon distribution may provide them a disincentive from obviating distribution upgrades.

Utility as a Meta-Aggregator.

Under this scenario, a non-utility third party aggregator serves as the intermediary between the customer and the utility. The utility aggregates the grid services and manages the services they can provide to the distribution system and the wholesale market. Just as the utility has no direct interaction with the customer, the aggregators would have no direct interaction with the wholesale market. Utilities would bid in all vehicles in their service territory as one resource into the wholesale market, and then direct aggregators to fulfill the wholesale market commitments.

This approach would eliminate conflict between the distribution needs and wholesale market needs, since the utility would be responsible for managing both services. Combining these into a single tariff would reduce complexity for aggregators, as they would only need to respond to a single VGI signal from the utility, rather than reconciling different signals from the utility and wholesale market. The utility would also not have to be directly involved in customer's transportation decisions. Allowing non-utility aggregators the opportunity to provide services to customers would introduce competition into the customer relationship-aspect of these services. This is the most critical area for competition, as managing the direct customer participation is critical to encouraging enrollment and ensuring that the aggregator responds to customer needs.

This approach could limit direct customer participation in the wholesale market. Aggregators may still be able to bid into the wholesale market under Rule 24, but rules would need to clearly define when and how the resource could be used by the utility. While this appears to add regulatory complexity, Rule 24 implementation may already need to address this challenge in a broader context.

Allowing only utilities to represent PEV load in the wholesale market might miss an opportunity to introduce additional competition into the wholesale market. The Commission would need to carefully monitor the utility treatment of the aggregators to ensure that aggregators were properly compensated and that their resources were efficiently used. Absent competition in aggregating to the wholesale market, utilities may be prone to keep an excess portion of the grid value, rather than transferring it to their aggregators, who would compete to return value to drivers.

Competitive Aggregation Market without Utility Participation.

A third option is to have utilities play no role in aggregation. Non-utility aggregators would be solely responsible for aggregating vehicles to provide services to both the wholesale energy and ancillary services market and to the utility for distribution system benefits. In order to provide services to the distribution system, the utility would have to develop price signals that capture the costs and benefits from PEV charging and grid services. It would also need to develop a means of communicating these price signals to aggregators and customers. Capturing utility benefits and allowing third-party wholesale access for the same resource would introduce the need to establish rules that allow these two functions to co-exist, as described above.

Existing CPUC policy already endorses the concept that customers should be able to access the wholesale market. CPUC has already endorsed the concept that retail customers should be able to access the wholesale market in Decision 12-11-025 in the Rule 24 proceeding. Rule 24 will need to be fully implemented in order for third-party vehicle aggregators to play this role.

Hybrid Market Approach.

A fourth option would be to allow utilities and third-party aggregators to compete for customers, rather than limiting utility involvement. The Commission would have to develop a framework that allows these entities to compete on a level playing field, but could result in a market structure that preserves competition and maximizes opportunities to access both wholesale and distribution benefits.

How do utilities capture distribution benefits?

In addition to the wholesale market, the distribution system can benefit from VGI. Capturing the benefits from meeting distribution system needs can contribute to the long-term sustainability of VGI business models. It also creates potential benefits for general ratepayers, by reducing infrastructure costs. This opportunity also represents a threat to the existing utility business model, as it will diminish one of their sources of revenue in a decoupled market.[54] In order to overcome this barrier, the Commission may need to create an incentive system that would encourage the utilities to consider the value of VGI in their planning and operations.

The utilities should create tariff options that allow retail customers to receive the value of providing services to the distribution system, while also allowing these customers the opportunity access the wholesale market. These tariff options must be harmonized with existing interconnection rules and designed with the consideration that mobility services are the primary end use for vehicle batteries.

A distribution ‘signal’ would manage the use of distribution system to prevent overloading a transformer or line capacity. For example, a Distribution Management Tariff could manage vehicle charging via a simple traffic light approach: the utility would provide simple signals to the customer to indicate when they can charge and when they cannot. For example, a green light could indicate that the utility would benefit from VGI services, while a red light could indicate that services would be detrimental to the distribution system. In exchange for abiding by these signals, the utility would provide a customer a rebate or other incentive for the value of the avoided distribution cost.

An alternative approach would be a Renewable Energy Integration Tariff, which could be a bonus payment, lower rate, or rebated amount for allowing the utility to smart charge a vehicle to follow the requirements from variable renewable energy generation. Under this approach, the utility could serve as the aggregator or meta-aggregator, bidding those services into the wholesale market to meet system-wide needs. Alternatively, it could simply manage the vehicles’ charging to integrate renewable distributed generation on the circuits throughout their local system.

Customers should retain the ability to override utility signals when participating in such programs, but in that case they would lose benefits from forgoing the transactions with the utility.

These tariff rules should be developed to support the receipt of value from grid services provided by individual and aggregated vehicle loads. For grid services provided by an individual vehicle load, the tariffs would function as any other utility tariff, directed at the utility customer. This approach might require some ability for load control by the utility, which might require separate metering of the PEV.

Distribution signals would also have to harmonized with the aggregator model chosen. Under the current model for aggregation used by the demand response program, an aggregator does not act as a customer to the utility. Under the DR model, it may be beneficial to allow the aggregator to receive the distribution signal, although the customer may be able to manage this on their own. Utility PEV tariffs could be made available to aggregators, who act as customers to the utility, depending on the aggregator model used. Aggregators would get the benefits of following the utility charge signals and retain ability to access the wholesale market.

What is the primacy among various grid services?

Grid services from vehicles can be directed to one of three places: the facility, the distribution system, or the wholesale market. As described in Section 2, PEV could serve a variety of needs for each of these beneficiaries. Coordinating actions intended to serve the system's operational requirements is necessary to maximize the benefits of vehicle-grid integration.

The needs of these three beneficiaries may conflict at a given time. For example, the wholesale market may have an imbalance that requires additional load, sending out a 'regulation down' signal to its ancillary service awardees. However, simultaneously, certain distribution feeders may already be overloaded. Absent coordination, an entity on this particular circuit could receive conflicting signals from the utility and the wholesale market, with the wholesale market asking for additional load, while the utility requests a decrease in load. It is unclear how the resource would respond to these competing requests. Maximizing the total benefits from VGI requires harmonization between the utility needs and the CAISO needs.

Several possibilities exist for reconciling these competing needs. CPUC and CAISO could prioritize the signals sent to PEVs such that their responses optimized VGI benefits. An evaluation of each of the different types of signals based on transmission and distribution constraints; economic or environmental value to participants, the utility, and society; or a resource's abilities could serve this function. If the utility serves as the aggregator, the utility could serve to balance these competing needs on its own, deploying resources in response to wholesale market signals that minimize impacts on the distribution system. If the utility is not the aggregator, it could also use price signals to the customer or aggregator to encourage them to behave in a way that efficiently uses the distribution system. Such a price system may require geographically-differentiated signals, though the development of smart grid communications may, in the future, reduce the cost of implementing and operating such a system.

It is unclear how often the grid needs for the distribution system and wholesale markets will be contradictory at a given time. The wholesale market can specify what geographic area, called sub-LAPs, it wishes to use for grid services. These areas may tend to experience similar weather and load patterns, likely reducing the rate of conflicts between the utility and the wholesale market. However, these conflicting needs are likely to occur more frequently in the future as more distributed generation is added to the utilities' distribution circuits.

Additional Regulatory Questions

In additional to the four questions identified above, other issues must be resolved in order to implement VGI. These issues are dependent on the issues identified above and should be addressed in response to the questions above, which will narrow the scope of these issues.

- *Safety.* Many PEVs receive top 5-Star Safety Ratings on multiple rigorous tests within the New Car Assessment Program, conducted by the National Highway Traffic Safety Administration.[55] The Commission should ensure that PEVs operate in accordance with all applicable safety and electrical standards and while off of the road and interconnected with the grid. Prior to the use of PEV storage to enhance energy reliability and resiliency during emergency or outage situations, the Commission will work with other State agencies to ensure codes and standards for equipment and facilities maintain the safety of consumers and utility operations.

- *Interconnection.* Based on the regulatory model that emerges from the questions above, the Commission and CAISO should evaluate what interconnection requirements are necessary for vehicle storage resources. Currently, all grid resources that access the wholesale market must have the following elements to enable the transaction:

    - Market participation authority through IOU via Wholesale Distribution Access Tariff (WDAT)
    - Contract with a Registered Scheduling Coordinator to manage and settle transactions
    - Registration with CAISO and assignment of a Resource ID
    - Execution of a Meter Service Agreement (MSA), Participating Load Agreement (PLA) and/or Participating Generator Agreement (PGA)
    - Integration under a resource product type (e.g. Proxy Demand Resource or Non-Generating Resource)
    - Approved method for measuring (metering) performance
    - Approved method to send and receive Automatic Generation Control signal from CAISO

    If a resource only faces the utility, the interconnection requirements have a different set of requirements, outlined in Rule 21. These requirements are different for a resource capable of bi-directional power flow and resources that do not bidirectional flow. Net Energy Metering offers additional simplifications to these requirements, though the current rules do not allow a battery storage resource to count toward NEM unless it exclusively stores renewable energy generation that is verified by a separate Net Generation Output Meter.

- *Wholesale market products.* The CAISO currently offers several different types of ancillary services products that may be useful to PEVs. These products could be used by whatever aggregation arrangement is determined appropriate by regulators. Experience will determine how well suited existing CAISO products are to the attributes of PEV resources. The current minimum size requirement of 500 kW seems to limit a VGI resource to fleets of multiple vehicles. A CAISO resource is not specific to one location, but can apply to multiple locations within one Sub-LAP. This policy would seem to support aggregation at any of the levels proposed above. Given the fast response time of existing lithium battery storage, CAISO should explore whether the grid would benefit from new products that are directed to capturing this benefit pursuant to FERC Order 755.

- *Utility tariffs.* Utility tariffs to capture VGI benefits will be necessary if the utility plays a role in vehicle aggregation. These tariffs would need to create the rules by which a vehicle can participate in VGI, including determining how the account holder is compensated for performance (and penalized for non-performance). As is the case for existing demand response tariffs, the utility does not necessarily need to compensate an account holder for each event. Monthly incentives or seasonal capacity-type payments might simplify the compensation approach. Alternatively, providing the value of a lifetime of projected benefits may be able to reduce the capital expenditure for a vehicle purchase.

  A substantial amount of early adopter customers (approximately 25 to 39%) also installed distributed generation and are enrolled in Net Energy Metering.[56] It is clear that customers are gravitating toward truly zero-emissions transportation while maximizing the utilization and economic return of their photovoltaic systems. Leasing options for photovoltaics and other distributed generation (DG), PEVs, and EVSE will drive continued demand and market expansion. Customers will want tariff solutions that accommodate the solutions now availed by carmakers and third party energy service providers.

  For certain commercial customers, it is possible that strategic utilization of capacity may not be possible if the facility's peak usage coincides with the time constraint when the vehicle must be recharged. Vehicle-grid integration in this case may require the installation of complementary solutions including distributed generation, stationary storage, control technologies, or coordinating the use of other available charging infrastructure to ensure the economic viability of electrification.

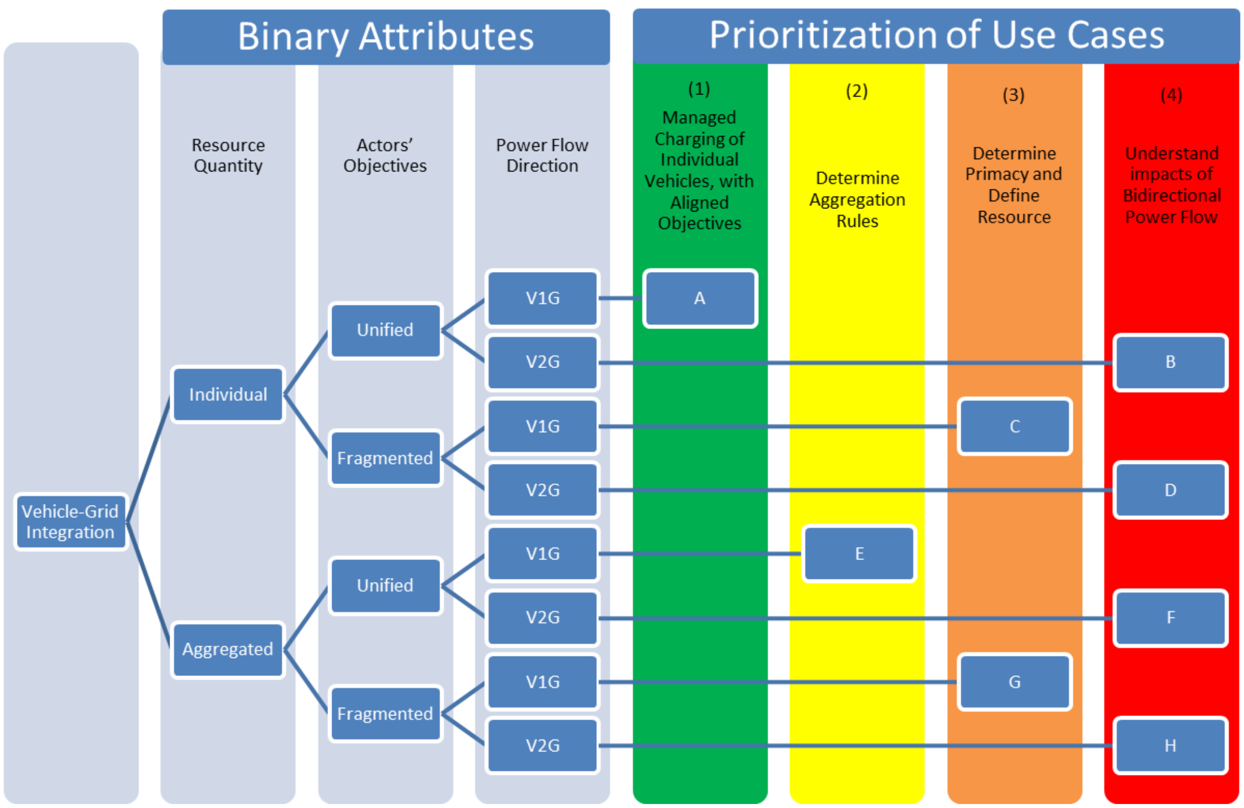
- *Metering and telemetry.* CAISO requires that any wholesale resource be able to meter its performance for ex-post verification. The CAISO metering requirements are currently being reviewed as part of its effort to expand metering and telemetry options.[57]

- *Communication Standards.* VGI introduces two types of communication functions: receiving wholesale market signals for the resource and sending meter performance data to the wholesale market. A communication standard will be required for sending messages between the aggregator (either the utility or non-utility third party) and the wholesale market. If the utility is the aggregator, it will necessary for the utility to determine a standard to use to communicate each of these message types. The standard must be capable of facilitating communication to the resource, but not necessary downstream of the resource. Standards will likely be needed to communicate downstream to ensure that each element is equipped to respond to the message, but it is not clear that these standards should be regulated or legislated. The communication of these downstream messages could use existing smart grid communication standards, such as OpenADR or SEP 2.0, or those in development including IEC 15118 and SAE J2847.

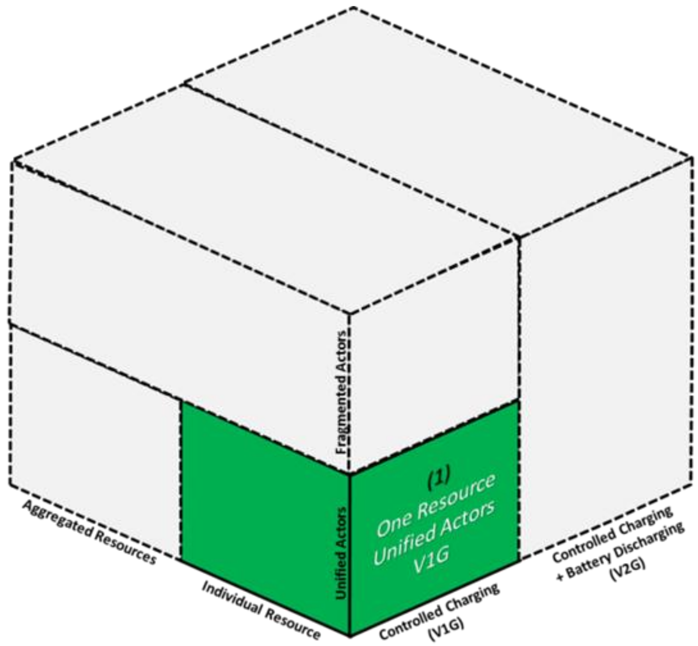
5. Next Steps for Vehicle-Grid Integration

A clear regulatory framework is necessary to realize the benefits of vehicle-gird integration. Fully implementing all the different iterations of VGI requires addressing four major regulatory questions, and a host of implementation issues based on the outcome of those questions.

The Commission and other California agencies should first prioritize use cases for commercialization. By building from simple use cases with fewer implementation barriers, to complex use cases, stakeholders can evaluate the value of different grid services and inform business strategies. The highest priority use cases appear ready for immediate implementation, while others require stakeholder consensus on the magnitude of grid benefits, commercial standards and regulatory framework. Enabling each use case requires that the additional regulatory considerations, listed at the end of Section 5, be addressed. Four issues should be specifically addressed for each use case: measuring benefits, tariff/product design, communication requirements, and metering requirements.



Use Case 1: Unidirectional Power Flow (V1G) with an One Resource and Unified Actor Objectives



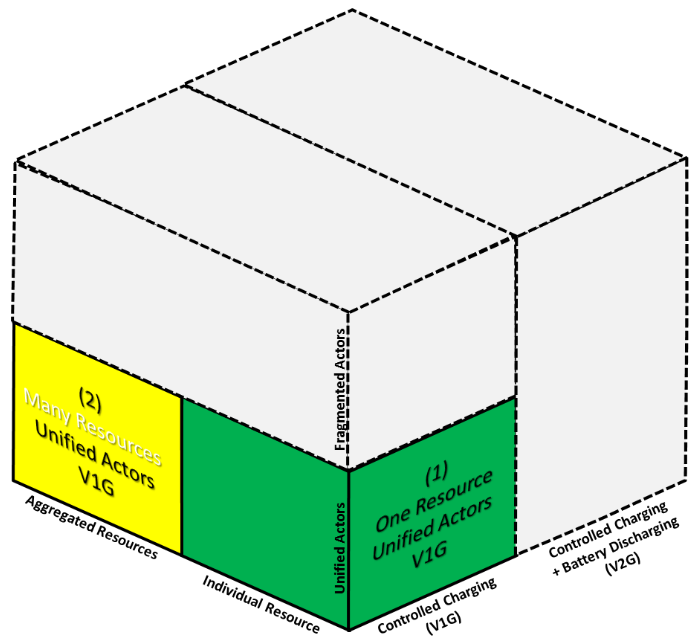
This use case appears to face no serious implementation barriers. None of the four major regulatory barriers need to be addressed to implement this use case. While the benefits of V1G are smaller than V2G, it can be implemented more quickly without compromising personal mobility or impacting the vehicles' battery life. Fleets represent a promising opportunity to integrate a large set of vehicles and realize a wide range of benefits. With a predictable charge pattern, these vehicles could be aggregated as a large resource, despite the small size of each vehicle. Additionally, V1G revenue could help improve the business case for fleet adoption by helping fleet owners reduce demand charges, which would help encourage fleet adoption. The "Unified Actors" subset can begin to be deployed now, as it do not raise the issues on the alignment of actor objectives.

- *Measuring Benefits:* Use Case 1 can provide three different utility benefits – demand response, off peak charging, and avoided distribution upgrade expenses. Demand Response for V1G fleet vehicles appears ready for immediate commercialization. Demonstration projects to calculate how managed charging may avoid distribution upgrades should also begin now through existing PEV fleets.
- *Tariff/Product Design:* For an entity that is already providing demand response, the utility should clarify the rules by which the vehicle load can contribute to its flexible DR load.
- *Communication Requirements:* The utility should explore different communication options that optimize response time from these resources. Until the resource is defined (at the vehicle, EVSE, or facility level) a variety of communication alternatives may be available. The utility should evaluate the options, especially those that CAISO is exploring as part of its metering and telemetry working group.
- *Metering Requirements:* Under this resource model, it is not clear that new metering requirements are needed. Using the existing Smart Meter measurements may to satisfy utility requirements. The utility should explore using alternative metering options, including submetering, that align with the options CAISO is exploring as part of its metering and telemetry working group.

Utilities should develop tariffs that immediately allow PEV fleets to test the value of vehicles as a DR resource. While the exact DR value of controlled charging has not been quantified, existing values can serve as a reasonable proxy until the utilities can determine PEV-specific estimates that evaluate integration benefits. After successful implementation with fleets, utilities should explore implementation in workplace and residential fleets. SDG&E's ongoing Experimental Rate Pilot and PG&E's current Demand Response PEV Pilot may help evaluate the benefits with V1G.

Use Case 2: V1G with Aggregated Resources

Use Case 2 requires that the Commission determines who can aggregate resources across different locations. Because this case assumes that the actors are unified, it is not necessary to define what end-use device comprises the resource. The treatment of aggregators should be made within the context of Rule 24, which allows retail customers to access the wholesale market, and the existing demand response programs.



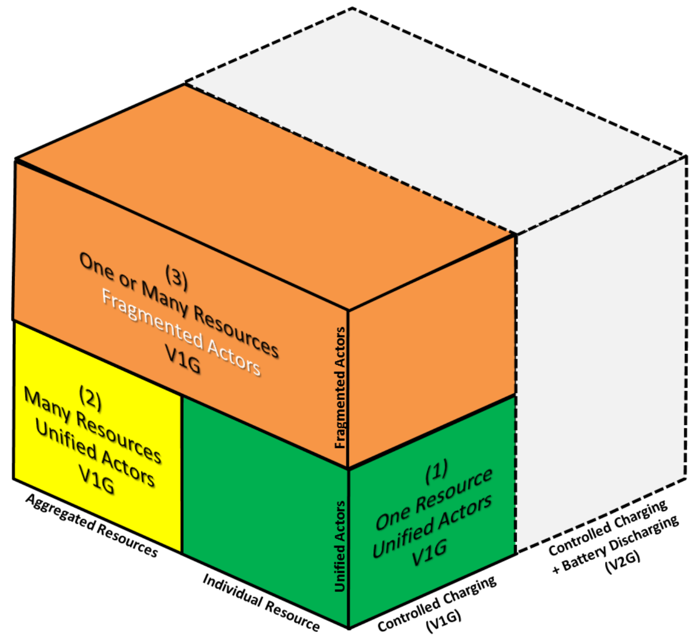
- *Measuring Benefits:* An aggregated resource could potentially help the utility deal with renewable ramps in the morning and evening and mid-day overgeneration. The utility should explore the value of grid benefits associated with this function. The utilities and third-party aggregators should execute pilots to determine how aggregators can provide value to both the utility and the wholesale market. These pilots should allow the aggregator to provide value directly to the wholesale market, to help understand the implementation challenges associated with behind-the-meter wholesale transactions. SCE's pilots with the Department of Defense can serve as a baseline for implementing pilots that allow for wholesale market access for a behind-the-meter resource. Testing this use case will provide insight to the marginal benefits to a PEV owner by participating as part of an aggregation, compared to the benefits of controlling the facility's energy and demand costs.
- *Tariff Design:* A renewable ramping product for a third-party aggregator will require that the utility establish aggregator rules and/or tariffs for aggregator services. These can be piloted now using existing aggregators and EVSPs.
- *Communication Requirements:* Communication requirements will be determined by the regulatory structure for aggregators.

- *Metering Requirements:* New metering requirements may be necessary to measure an aggregated resource. Rules allowing the use of direct metering and submetering will need to be developed. These rules should mirror that of the wholesale market requirement for other energy resources.

The Department of Defense's Vehicle to Grid Pilots, in which SCE will act as the resource's Scheduling Coordinator, should serve as a guide for implementing related pilots. Each utility should explore how they and third-party aggregators can provide value to the grid and their customers by testing different aggregation approaches.

<u>Use Case 3: V1G with Fragmented Actor Objectives</u>

Fragmented Actors introduces the question of who controls the resource. Parties involved in a given transaction may be able to reach an agreement bilaterally as to which entity controls the resource.[58] If the market cannot resolve conflicting objectives, then the Commission and CAISO many need to define the resource. Accelerated market implementation will likely require that the Commission and CAISO determine the location of the resource.

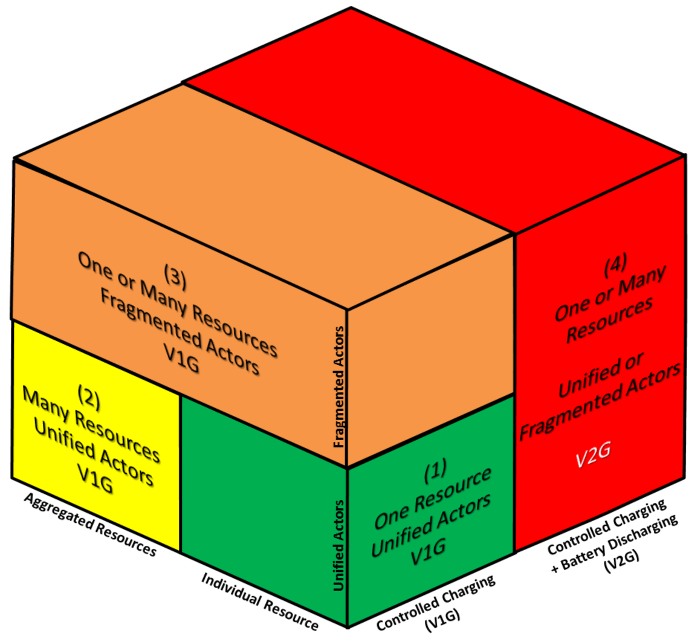


- *Measuring Benefits:* Fragmented Actors does not raise new issues related to benefits to the grid. Insight regarding the value of grid services is derived from Use Cases 1 and 2 can inform this use case. However, fragmentation may reduce the overall benefits that the end use customer or a facility owner receives from participating in a VGI transaction.
- *Tariff Design:* Utility tariffs directed to fragmented resources will need to be developed for a determined 'resource location', or if the Commission and CAISO decide not to address this issue, then tariffs will need to allow for multiple locations to be used. This may introduce the need for the utility design new tariffs directed to an entity that is not account holder at a particular location. If the lack of a resolution on the resource location issue erects market barriers to VGI with fragmented actor objectives, the Commission and CAISO may instead need to address the primacy of grid services. This would require tariffs that clarify which grid needs should be principally satisfied during VGI.
- *Communication Requirements:* Communication requirements should use national standards and should reflect the treatment of resource location, if the resource location is determined through regulation.

- *Metering Requirements:* The resource location may introduce a need the need to use a non-utility owned meter located closer to the point of charging to measure the ability to accurately perform grid a service.

<u>Use Case 4: Bi-directional Power Flow (V2G)</u>

Prior to implementing rules for bi-directional power from vehicles, the Commission should determine if automakers are developing commercial technologies in this space. While V2G increases the potential resource size and duration of service, it can only be implemented with the support of automakers. Any action toward realizing the V2G use cases must ensure that driver mobility is not negatively impacted and the structure of the battery warranties are not voided. Automakers should be engaged to determine when and if this technology will be commercially available under terms that automakers and customers can accept.



- *Measuring Benefits:* V1G and V2G appear to be able to provide nearly all the same types of benefits for the wholesale market. However, the ability of V2G to provide power quality and reliability benefits directly to end users and the distribution system requires that utilities consider the impacts and benefits of bi-directional vehicle storage on their distribution systems. Customers should also consider the value of increased power quality and reliability on their energy needs.
- *Tariff Design:* Bidirectional power flow raises interconnection issues that do not apply to V1G. Any grid resource that can provide two-way power flow needs to adhere to utility and CAISO interconnection requirements. These requirements become more complicated if the bi-directional resource can backfeed onto grid beyond the point of the primary meter, rather than reducing the site's load while discharging and overall energy consumption. Utilities will likely need to develop separate requirements for resources that can backfeed and resources that cannot. It is unclear how net energy metering (NEM) rules will apply to a vehicle resource, as NEM rules that accommodate accessory storage systems are intended to apply only to renewable generation resources. The NEM proceeding is currently determining how to address battery resources under the NEM framework. That process can inform how the Commission will treat vehicle storage resources. The Commission should

determine whether NEM tariff issues specific to vehicle storage should be addressed in the alternative-fueled vehicle proceeding or the NEM proceeding.

- *Communication Requirements:* No new communication requirements are necessary, although standards will need to include specialized messages for bi-directional power flow.
- *Metering Requirements:* Metering requirements in this case will largely depend on where the resource definition places the resource. Direct metering or submetering may be necessary to enable bi-directional power flow, as the utility will likely need some way of verifying the service rather than the relying on the facility meter, especially for a customer that uses distributed generation.

Wholesale Market Access

The Commission is currently developing rules for how behind-the-meter resources can access the wholesale market. These rules will inform how behind-the-meter VGI resources will participate in the wholesale market. There are two issues unique to VGI that should also be considered.

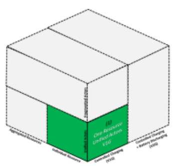
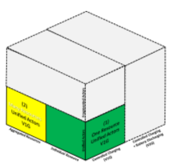
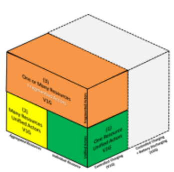
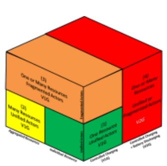
- *Determine the priority of VGI services between distribution and wholesale market activities.* A regulatory decision on the priority of distribution and wholesale benefits is necessary to avoid conflicts that might stifle market development.
- *Evaluate the benefits of a very fast responding resource and how those benefits could be captured in a wholesale market product or a utility product.* Current CAISO products in the ancillary service market are designed with the needs of large generators in mind. VGI represents a fast-responding, small resource spread throughout a service territory. Capturing these characteristics in a CAISO product design could yield greater benefits to the grid. CAISO, utilities, and stakeholders should work together to evaluate these potential benefits and determine if there is benefit in modifying existing products or creating new ones to capture this particular attribute of VGI.

Zero Net Energy Building Requirements

Customers' future investments in PEVs, charging infrastructure, and the electricity needed for operations implicate the State's concurrent efforts to get buildings PEV-Ready and use Zero Net Energy (ZNE). Since a ZNE building may be defined as one where the societal value of the annual on-site renewable energy produced is equivalent to the value of energy consumed by the building, ZNE evaluation principles should ensure that incentives for PEV adoption are preserved. This consideration will depend on the update to the methodology in calculating the Time Dependent Valuation, which evaluates the cost-effectiveness of energy efficiency measures based on the time at which savings occur.[59]

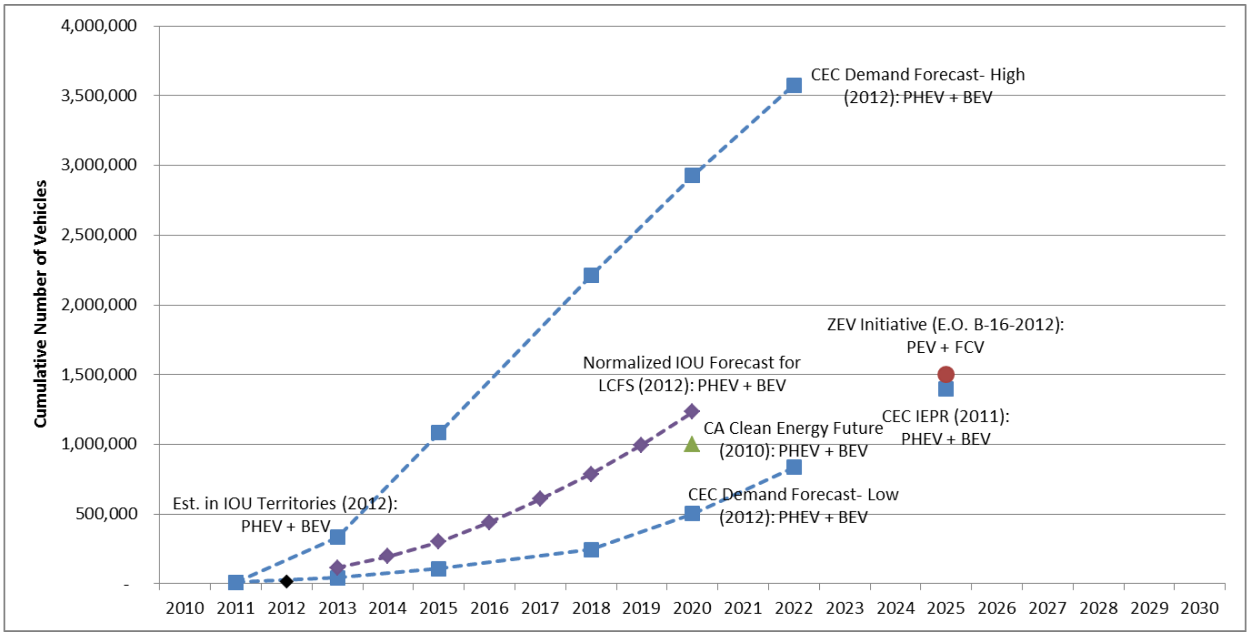
Use of National Standards

Standards-making bodies are currently developing technical communication standards that can support a variety of business models in the VGI space. This effort allows market competition to empower customers to select a technical standard that is most appropriate for their needs. Government entities can best support this process by engaging with standards-making organizations, rather than pre-determining the outcome of this process. If necessary, California state agencies should express preferences for general outcomes, rather than technology-specific solutions.

Scenarios and Needed Actions for Vehicle-Grid Integration	**Customer Benefits**	**IOU/Distribution System Benefits**			**Wholesale Market Benefits**		
		Tariff Design	Communication	Metering	Product Design	Communication	Metering
One Resource **Unified Actors** **V1G** 	No action needed.	Define DR Value and develop tariff Measure benefits for renewable-following and neighborhood scheduling through demonstration projects Develop tariffs for DR and other distribution benefits	Select Communication Standard(s)	Choose to use facility meter or resource meter	Refine NGR and PDR products to account for the response time, size and flexibility of a vehicle resource	Select Communication Standard	Define metering location and accuracy requirements
+Aggregated Resources 	Determine the marginal benefits of subscribing to an aggregation program.	Develop products to support aggregated resources	Determine communication requirements for an aggregated resource	Determine metering requirements for an aggregated resource			
+Fragmented Actors 	Determine the marginal benefits of a regulatory solution to the agency issue.	Design tariffs based on the resource definition	Determine communication requirements based on resource definition	Determine metering requirements based on resource definition			
+V2G 	Determine impacts to reliability, economics and customer mobility.	Wait to develop rules until automakers indicate when commercial technologies will be available. Determine incremental benefits, tariff, and interconnection requirements for bi-directional resources.					

6: Appendix and End Notes

Figure 14: Estimates, forecasts, or goals for Zero Emissions Vehicles or Transitional ZEVs.



---

[1] California Executive Order B-16-2012.

[2] California Energy Commission (CEC), California Energy Demand 2012-2022 Final Forecast, June 2012. Table 1-10, page 39. Capacity based on "High Scenario" shares of cumulative vehicles and charging levels of 6.6 kW for BEVs and 3.3 kW for PHEVs. For comparison, the "Low Scenario" results in a total load of 6,000 MW in 2022.

[3] D.11-07-029, pages 14-15.

[4] U.S. Department of Energy (DOE) Alternative Fuels Data Center, Light-Duty Vehicle Search. Tesla Motor, Model S Facts. The size of the inverter either within the vehicle or within associated a stationary EVSE would limit the amount of power a vehicle battery would be able to provide.

[5] Nissan Motors, Leaf to Home Electricity Supply System. Burns & McDonnell, SPIDERS Delivers First-of-a-Kind Bidirectional Electric Vehicle Charger at Fort Carson, Colorado, August 30, 2013.

[6] Advice Letters PG&E 4077-E and SCE 2746-E submitted pursuant to D.12-04-045.

[7] Estimated $500/kWh for the battery capacities of model year 2013 battery electric vehicles.

[8] Oak Ridge National Laboratory, National Household Travel Survey. Table 15 on page 31. This level of utilization is consistent with a conservative estimation that California vehicles are parked approximately 96% of the time, assuming an average 1-way commute in California of 26.9 minutes per the American Community Survey). Charging data for Figure 2 is based on data from the EV Project Reports.

[9] National Household Transportation Survey 2009, daily travel log data. 398 vehicles were randomly sampled from this data set. The results reflect unweighted survey results. The 'Other' Location includes any location code except home, work, and driving. Location codes were rounded to the nearest 15 interval.

[10] Idaho National Laboratory, EV Project Reports, 2011-2013. An American Recovery and Reinvestment Act-funded EV and charging infrastructure deployment project collected data on energy use and charging behavior in 21 metropolitan areas. Energy Division's analysis of the EV Project referenced in this paper is based on data from Q2 2011 to Q2 2013 for Los Angeles, San Diego, and San Francisco, CA.

[11] Joint California Investor Owned Utilities (Joint IOUs), Electric Vehicle Load Research Final Report, December 28, 2012. Chart SDG&E-4 suggests that lower vehicle charging energy use on Sunday and Monday are more characteristic of "weekend" energy use than during Saturday and Sunday.

[12] Two major forces may substantially change the capacity utilization of PEVs. First are alternative notions of car usage and ownership. Driven by shifts in mobility preferences and the proliferation of personal digital technologies, a variety of new transportation business models that enable the sharing of rides or vehicles themselves may limit the number of agents with which a utility interacts to integrate PEVs. Second is the combination of sensing, control, and communication systems within vehicles which could enable partial- or fully- autonomous driving. The integration of these systems may substantially improve the precision of charge scheduling but perhaps decrease total amount of time they are connected to the grid. However, the ability to seamlessly replace depleted batteries or recharge them via high-power stationary or wireless in-road EVSE enhances the case to coordinate vehicle-grid integration to minimize impacts and costs on the electric system.

[13] DOE/Electric Power Research Institute (EPRI), Electricity Storage Handbook in Collaboration with NRECA, pages 4-28. The list of applications here is not intended to be exhaustive. Energy Division's alterations from the Handbook's list does not imply the technical or economic infeasibility of PEVs to serve certain applications.

[14] CPUC, A Review of Current Issues with Long Term Resource Adequacy, February 20, 2013.

[15] California Independent System Operator (CAISO), Comprehensive Forward Capacity Procurement Framework, February 26, 2013.

[16] CAISO, Demand Response and Energy Efficiency Roadmap, June 12, 2013. Page 12. Flexible Capacity is defined qualitatively with three operational attributes including Maximum Continuous Ramping, Load Following, and Regulation.

[17] CAISO, 2014-2016 Strategic Plan, September 2013. Pages 2 and 7.

[18] CPUC, D.13-10-040, pages 5, 14, 28, 32, and 75.

[19] CEC 2012 and California Center for Sustainable Energy (CCSE), CVRP Statistics, October 21, 2013. CEC's 2012 Low and High Scenarios for PHEV and BEV adoption were used, but de-rated since IOU customers account for about 80% of total Statewide CVRP participants. PHEVs and BEVs were assumed to charge at 3.3 kW and 6.6 kW, respectively. For the 2-Way estimate, vehicles capacity accounted for the total range of operation, charging and discharging.

[20] CPUC, Qualifying Capacity and Effective Flexible Capacity Calculation Methodologies for Energy Storage and Supply-Side Demand Response Resources Draft, September 13, 2013. Page 13.

[21] California Executive Order S-03-05

[22] California Air Resources Board (CARB), Climate Change Scoping Plan First Update Discussion Draft, October 2013. Page 86-91.

[23] California Council on Science and Technology (CCST), California's Energy Future- The View to 2050 Summary Report, May 2011. Page 4.

[24] CCST, California's Energy Future- Transportation Energy Use in California, December 2011. Page 22.

[25] Williams et al, The Technology Path to Deep Greenhouse gas Emissions Cuts by 2050: The Pivotal Role of Electricity, Science, January 2012. Page 54-55.

[26] Joint IOUs, Assessment Report for PEV Notification, December 23, 2011.

[27] Joint IOUs, Electric Vehicle Load Research Final Report, December 28, 2012. Page 3-4.

[28] CPUC, Biennial Report on Impacts of Distributed Generation, May 2013. Pages 1-5 and C-6.

[29] D.11-07-029, pages 26 and 28.

[30] Ibid at page 77, Finding of Facts 7 and 11.

[31] D.11-07-029 and D.13-06-014 respectively established and extended the common treatment of PEV-related distribution costs in excess of the Rules 15 and 16 allowances. E-4514 and E-4595 provided temporary rates for two government customer electric fleets.

[32] For example: residential, public, or fleet charging of light-duty vehicles or fleet charging of medium and heavy duty vehicles.

[33] Lawrence Berkeley National Laboratory, Los Angeles Air Force Base Vehicle to Grid Pilot Project, June 8, 2013. Page 12.

[34] Massachusetts Institute of Technology Lincoln Laboratory, Enhanced Plug-In Hybrid Electric Vehicles, 2011. Page 4.

[35] Assumes that the vehicle is charging 1.6 hours per day, equal to approximately 32 miles per day and that the resource receives the full value ($140 per kW-year) of the avoided generation capacity at peak hours. Analysis of charging behavior is needed to determine the exact value of DR from a PEV resource.

[36] Interstate Renewable Energy Council, A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, October 2013.

[37] "Average load" was calculated as the quotient of the average kWh per charge event and the average hours per charge event, for both weekdays and weekends.

[38] D.13-06-014, page 21.

[39] This distinction of impermanent interconnection is not intended to contravene the finding that it was appropriate to designate PEV load as new and permanent in D.11-07-029, page 54 and D.13-06-014, page 21.

[40] D.11-07-029, Section 5.

[41] Joint IOUs, Electric Vehicle Load Research Final Report, Tables PG&E-7, SCE-9, and SDG&E-1.

[42] Id, page 46.

[43] San Diego Gas & Electric, First Year Evaluation for San Diego Gas & Electric's Electric Vehicle Pilot, page 15-16.

[44] Energy Division analysis of EV Project Reports data in California from Q2 2013.

[45] Joint IOU Electric Vehicle Load Research Final Report, pages 17, 37, and 46.

[46] Data on the timing and magnitude of PEV load is particularly important for the potential implementation of electric transportation tariffs. SDG&E separate meter customers use approximately 7 kWh/day on Sunday-Monday and 9 kWh/day

Tuesday-Saturday. For comparison, the EV Project's data for San Diego show that there is only a 19% difference in weekday (Monday-Friday) and weekend (Saturday-Sunday) energy use.

[47] Energy Division analysis of EV Project Reports data as of Q2 2013. Residential Level 2 charging might allow for staggered, managed charging or bidirectional power flow since the PEV is drawing power for only 20% of the time it is plugged in. Conversely for DC Fast Charging, since power is needed immediately and drawn for 100% of the time that it is plugged in, VGI benefits may be limited to demand during excess electricity generation.

[48] Energy Division analysis of EV Project Reports data as of Q2 2013. On average in Los Angeles and San Diego, Nissan LEAFs charge 1.06 times/day while Chevrolet Volts charge 1.36 times/day.

[49] A grid resource connected under a NEM tariff would simplify the interconnection process. However, current NEM rules prohibit the use of non-renewable resources under a NEM tariff, which may prohibit a vehicle resource from NEM eligibility.

[50] Battery warranties range among models, but in general, are warrantied for a portion of the vehicle's lifetime (years) and mileage (tens of thousands of miles). The GM Volt's battery management systems are designed with sensors and algorithms to prohibit implementing a charge command in ways that would void the warranty. VERGE San Francisco, "Turning Cars into Batteries," October 15, 2013.

[51] Some individual buses and heavy-duty vehicles may exceed the 500 kW resource size

[52] Society of Automotive Engineers (SAE), SAE Charging Configurations and Ratings Terminology, 2011.

[53] "Load" is defined in the CAISO Glossary as "An end-use device of an End-Use Customer that consumes power." Non-Generating Resource is defined in the Replacement CAISO Tariff, May 18, 2010.

[54] The addition of PEV load may require additional infrastructure which might not be fully offset by VGI benefits to the distribution system.

[55] National Highway Traffic Safety Administration (NHTSA), SaferCar.gov - 2011-Newer Vehicle Ratings, 2013. In addition, automakers and standards-making organizations are working with national associations and Federal Agencies to ensure the safety and preparedness for PEVs. NHTSA, Electric Vehicle Safety Symposium, 2012.

[56] Joint IOUs, Electric Vehicle Load Research Final Report, pages 13, 25, 42. CCSE, CVRP Survey, May 2013.

[57] CAISO, Expanding Metering and Telemetry Options Stakeholder Process.

[58] The Coase Theorem (1960) suggests that the initial allocation of a property that generates externalities is not a barrier to an efficient allocation of resources, assuming that parties can trade amongst themselves. In the case of VGI, parties may be able to bargain with one another to arrive at an efficient outcome (i.e., the provision of services in the face of fragmented actors). However, as Coase points out, transaction costs can make bargaining too costly for parties, which may require intervention to ensure an efficient outcome.

[59] CEC, Time Dependent Valuation of Energy for Developing Building Efficiency Standards, February 2011.