ASSESSING THE ECONOMIC VIABILITY OF ELECTRIC VEHICLE-TO-GRID SERVICES THROUGH INFRASTRUCTURE AND MARKET PARTICIPATION INVESTMENTS

By

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ABSTRACT

ASSESSING THE ECONOMIC VIABILITY OF ELECTRIC VEHICLE-TO-GRID SERVICES THROUGH INFRASTRUCTURE AND MARKET PARTICIPATION INVESTMENTS

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Plug-in electric vehicles (PEVs) have the potential to not only reduce CO_2 emissions from transportation, but also serve as distributed banks of energy storage for grid operators in a service called Vehicle-to-Grid (V2G, V1G). The need for energy storage will become increasingly crucial as intermittent sources of renewable energy are integrated. Previous studies have claimed that providing V2G/V1G services to the grid will generate annual revenues on the order of $2,500 per PEV from the frequency regulation market (Kempton & Tomić, 2005a). In this relatively lucrative market, small power draws to and from the resource enable the correction of imbalances in the net load on the grid. Bids are secured independently for regulating the load down or up, allowing PEVs to manage the power in their batteries to either charge as normal (V1G), or both charge and discharge (V2G).

No known prior studies include the cost of the infrastructure and market participation fees necessary to provide this service, suggesting that initial revenue estimates are optimistic at best. In order for a fleet operator to break even over the lifetime of the investment, an annual average market clearing price of $36/MW-h is necessary for V2G fleets and $6.40/MW-h is necessary for V1G fleets. The current average price for this service is $5/MW-h, and has been dropping over the last three years. Unless this price increases, the cost of V2G/V1G equipment and market participation declines substantially, or subsidies are introduced, it will be economically difficult for this service to move beyond the pilot project phase.

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To my husband Ryan, I want to thank you for supporting my career, including taking a chance with yours, and moving us halfway across the planet. Thank you for trusting in me, in us, and in the future. You have been my anchor for the last eight years, and you have helped me grow in ways that are immeasurable. You too are transcendent (Campbell, 2008,

x), and I love you more with each day. Thank you for your unwavering support throughout both of my experiences in graduate school, and thank you for sharing your life with me.

Finally, I would be remiss without acknowledging the “internal” motivational support provided by my future daughter. I hope that I can teach you that you are strong, your thoughts are valuable, and you can really do anything you want – all it takes is effort, little by little.

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List of Acronyms

ACE - Area Control Error

AGC - Automatic Generation Control

BEV - Battery Electric Vehicle

CAISO - California Independent System Operator

CEC - California Energy Commission

CPUC - California Public Utilities Commission

CPS - Control Performance Standards

DR - Demand Response

EVSE - Electric Vehicle Supply Equipment (Charging Station)

ECN - Energy Communication Network

FERC - Federal Energy Regulatory Commission

ISO/RTO - Independent System Operator/Regional Transmission Organization

ICE - Internal Combustion Engine

IOU - Investor Owned Utility

LA AFB - Los Angeles Air Force Base

LBNL - Lawrence Berkeley National Laboratory

MCP - Market Clearing Price

NGR - Non Generating Resource

NERC - North American Electric Reliability Corporation

PEV - Plug-in Electric Vehicle

RPS - Renewable Portfolio Standards

VGI - Vehicle-Grid Integration

V2G - Vehicle-to-Grid

V1G - Grid-to-Vehicle

WECC - Western Electricity Coordinating Council

1 INTRODUCTION

Plug-in electric vehicles (PEVs) have the potential to not only eliminate tailpipe emissions of carbon dioxide, but also to serve as distributed banks of power for the grid (Hawkins, 2001; Kempton et al., 2001; Brooks & Gage, 2001; Letendre et al., 2006). The need for the type of electrical storage that PEV batteries could potentially provide will become increasingly crucial as intermittent sources of renewable energy are integrated into the grid mix (Loutan & Hawkins, 2007; Makarov et al., 2009). If all existing PEVs in California – 1.4% of light duty vehicles currently on the road – were enabled by grid operators to provide storage support services, they could store 1.3% of the daily power generated from renewable energy, or 4% of the daily power generated from solar photovoltaic systems (CAISO, 2014b; Ingram, 2014).

In anticipation of the growing fraction of electricity generated from intermittent sources, two hurdles must first be overcome: (1) the reserve of electrical storage must grow substantially – and if PEV batteries are to play a key role, this means a large growth in electric vehicle sales; and (2) the framework for the compensation of this service to the grid needs to be established. Allowing electric vehicles to provide ancillary services to the grid can promote adoption rates by establishing economic pathways for PEV owners to be compensated for providing a service to the electric grid. This compensation framework is currently being established in Delaware with a net metering allowance for PEVs and in California with a Vehicle-Grid Integration roadmap partnership between the California Public Utilities Commission (CPUC) and the local balancing authority, the California Independent System Operator (CAISO) (Senate Bill 153, 2009; CAISO, 2013).

If existing ancillary service compensation mechanisms could be applied to PEVs, these vehicles would have the potential to earn annual net revenues on the order of $2500, sug-

gesting that the high upfront cost will be aggressively paid down with this revenue mechanism (Kempton & Tomić, 2005a). Several parameters have refined this estimate in the near-decade since it was published, including wear on the battery (Brooks, 2002; Han & Han, 2013), regional variance in driving and charging habits (Ecotality North America, 2012), and compensation projections based on historical trends for individual balancing authorities (MacDonald et al., 2012).

Although current and future pilot projects claim that the potential revenue from engaging PEVs with the ancillary service market far outweighs the operational costs of owning a PEV (i.e., purchasing electricity in comparison with gasoline) (Gorguinpour, 2013), little attention has been paid to the costs associated with enabling PEV owners to access this market, even as these necessary components are being clarified and, in some cases, purchased (Marnay et al., 2013). This thesis outlines the path that PEVs are beginning to take in supporting a power grid that will be progressively stressed by the aggressive inclusion of intermittent power sources and frames the potential for net revenue by quantifying the costs required for participation in the appropriate market.

The following chapter introduces the underlying motivations for these two parallel, and previously separate, pathways to reducing the impact of climate change – promoting the adoption of electric-drive vehicles, and integrating renewable power into the mix of electricity delivered on the grid.

1.1 Background

There is overwhelming scientific consensus that links the warming of Earth's average surface temperature with increasing atmospheric concentrations of greenhouse gases (Hansen et al., 2008). Although there are a host of greenhouse gases (e.g., carbon dioxide, nitrous

oxide, and water vapor), carbon dioxide (CO_2) is the single largest forcer, and its atmospheric concentration has increased due in large part to the combustion of fossil fuels since the dawn of the industrial age (Douthwaite, 2010; Pachauri & Reisinger, 2007). In order to effectively advise policy makers on a course of action to avoid irreversible effects of climate change, scientists have recommended a CO_2 concentration target of 350 ppm (Hansen et al., 2008). This target was largely informed by planetary ice sheet records of time periods in which the planet was ice-free until CO_2 concentrations fell to 450 ± 100 ppm.

In mid 2013, the atmospheric concentration of CO_2 surpassed 400 ppm, and the annual rate of increase was 25% higher than that of the previous decade (CO2Now.org, 2013). The urgency of not only reducing, but eliminating, CO_2 emissions, has never been more relevant.

1.2 Pathways For Reducing CO_2 Emissions

In the United States, nearly three-quarters of all CO_2 emissions come from two sectors: 39% are from the generation of electricity, and 34% are from the combustion of fossil fuels in vehicles (U.S. Energy Information Administration, 2013). Together, the reduction of CO_2 emissions in these sectors can have an enormous impact in allaying the irreversibility of climate change.

There are two distinct pathways that currently exist in parallel to facilitate the reduction of CO_2 emissions from these two sectors. The pathway for electricity generation includes the development of renewable energy generation sources, such as solar, wind, and micro-hydro, and the integration of these generation sources into the utility grid mix. Because there is little to no storage of electricity on the grid once it is generated, this pathway depends heavily on the regional availability of primarily intermittent renewable energy

sources.

In spite of this, industry-wide sales of residential photovoltaic panels have increased 33% in 2012, and are expected to keep growing (Solar Energy Industries Association, 2013). New installations of wind capacity accounted for 32% of U.S. electricity generation additions in 2011 (Wiser & Bolinger, 2011). Facilitating the integration of this mix of renewable power sources into the national electricity generation portfolio has the potential to eliminate a large fraction of all U.S. CO_2 emissions.

The pathway to elimination of CO_2 emissions in the transportation sector involves phasing out gasoline and diesel as the primary fuel source, and in some cases replacing them with grid-powered batteries, and others with alternative fuels. In the late 1970s through mid 1980s, this was catalyzed with aggressive fuel efficiency regulations. In the last three decades, however, the fuel efficiency standards have stagnated (Transportation and Climate Division, 2012). Only recently, with the inclusion of hybrid gasoline plus electric power vehicles spurred by regulations like the Clean Air Act of 1990, have the fuel efficiencies increased in order to reduce harmful emissions (U.S. Environmental Protection Agency, 2013). These vehicles harness an enlarged on-board battery pack that allows the driver to consume less gasoline by storing some of the otherwise wasted energy in the batteries. The batteries are typically charged by the combustion of gasoline as well as regenerative breaking. The technology from hybrid vehicles has lead to vehicles whose batteries can be charged directly from the electric grid, called Plug-in Electric Vehicles (PEV). To the degree that they replace existing internal combustion engine (ICE) vehicles, PEVs have a strong potential to contribute to a portfolio of solutions that will reduce domestic CO_2 emissions.

1.3 Barriers To Existing CO_2 Reduction Pathways

Each pathway for reducing CO_2 emissions established above comes with a host of barriers. For the generation of electricity, the growing capacity of renewables will need concomitant storage to facilitate their integration into the existing system. At the same time, although PEVs eliminate tailpipe CO_2 emissions, key barriers include the up-front purchase price of the vehicles and limited access to raw materials for battery and electric motor production. (Tsang et al., 2012, 12).

1.3.1 Barriers to reducing CO_2 emissions in the electricity generation sector

The existing framework for the generation and transmission of electricity was built around using fossil fuels, such as coal, as the primary source of energy. This original fuel stock meant it was most economically efficient to centralize the generation of electricity in a handful of large power stations, and since the energy was stored in easily accessible hydrocarbons, there was no need to store electricity once it was generated. As a result, today we have a utility grid that generates the bulk of power in a few massive power plants, where that power must either be consumed immediately, or lost.

Since there is little to no storage of energy on the grid, power must be consumed when it is generated. Although the inclusion of renewably-generated energy into the grid mix is growing, largely motivated by policies such as the Renewable Portfolio Standards, the base load power[1] in the United States is still provided by nonrenewables. For renewables to effectively replace fossil fuels in the generation of electricity, it will become necessary to store the energy generated by solar, wind, and other intermittent sources for use at a later

[1] Base load power is the minimum power level that an electricity generation plant must provide to meet basic power needs that are easily predictable over a long timeframe. See Section 2.2 and Figure 2.1 for further explanation of load management.

time.

1.3.2 Barriers to reducing CO_2 emissions in the transportation sector

At the same time, the pathway for reducing CO_2 emissions from vehicles has already approached a barrier: although PEVs are inexpensive to operate compared with their ICE counterparts, the up-front cost remains preclusively expensive, especially when charging equipment (Electric Vehicle Supply Equipment, EVSE) costs are included (Tsang et al., 2012; Hidrue et al., 2011).

The difference in purchase price of the vehicle is substantial. Often around $30,000, this hurdle has necessitated significant short-term subsidies to make PEVs comparatively competitive (Tsang et al., 2012). To offset the large initial investment, subsidies such as the $7,500 Federal Tax Credit are available to most consumers, but these are set to phase out for each manufacturer after 200,000 qualifying vehicles are sold (IRC 30D, 2013). Moreover, federal stimulus funds to plan and build public EVSE, meant to allay anxiety over the driving range of most PEVs, expired in 2009 (Jenkins et al., 2012). These short-term subsidies are meant to facilitate the adoption of PEVs until the purchase price is able to be reduced by economies of scale and learning curve gains (Alexander & Gartner, 2013; Hurst & Gartner, 2013). In order for the purchase price to come down in the future, policies are needed in the mean time to facilitate the acceleration of market adoption. Clearly, a consistent mechanism for softening the financial burden is necessary to encourage the adoption of PEVs.

1.4 Vehicle-Grid Integration: Merging The Two Pathways

Among the current pathways for eliminating tailpipe emissions from vehicles, replacing ICE vehicles with battery-electric and plug-in hybrid electric vehicles (BEV, and PHEV, respectively) presents a unique opportunity to address the primary barrier to the integration of renewables into the grid mix. All PEVs have batteries on board that, by design, store power from the grid. Although the primary purpose of this stored power is to move a vehicle, it is still essentially a battery that could also discharge power to the grid when necessary. PEVs have the potential to serve two functions: provide transportation to the driver, and provide storage of power, facilitating the integration of intermittent sources of energy. It is economically inefficient for utilities to purchase large banks of batteries to store power (von Meier, 2006); with PEVs, the batteries are privately owned by the citizen, while the power system operator pays the owner for the service of accessing the batteries.

As these two veins of energy consumption – electricity generation and personal transportation – adopt new technologies with the aim of reducing CO_2 emissions, it may become more convenient and efficient to merge these previously parallel endeavors for a handful of applications. The integration of PEVs with the grid can help to reduce CO_2 emissions from these two sectors at once: the adoption of PEVs can eliminate tailpipe emissions of CO_2, the integration of PEVs with the grid can provide a mechanism for storage of renewable energy, and the compensation of the service of energy storage in the PEV batteries may help facilitate the adoption of PEVs.

1.4.1 Power Markets and Compensation

Although there are insufficient PEVs to provide storage for energy on the grid from renewable sources right now (Kempton & Tomić, 2005b; Budischak et al., 2013; Shepard &

Gartner, 2013), there are other suitable power markets for small numbers of PEVs. There are four main power markets that grid operators use to control the flow of power: base load, peak power, spinning reserves, and frequency regulation. These will be described in more detail in Chapter 2. The grid operator must manage the flow of power in each market on several time scales, depending on both the predictability of demand, and the time it takes to bring additional power on-line, called ramp-up time.

Base load, for example, is both highly predictable and necessary at all times; the transition to renewable power will require a portfolio of solutions, including large amounts of storage. Typically, the ramp-up time for base load power is long, making it difficult for operators to displace some non-renewably generated electricity with cleaner sources. Peak power is predictable on a seasonal time scale; operators know, for example, that demand for electricity will spike in the afternoon hours in the summertime, when otherwise idle air conditioners are turned on. Since peak power is predictable in this way, the similarly long ramp-up time can be planned for. Spinning reserves are required to provide emergency power to the grid, for example if a generator breaks. To meet these requirements, power sources must be able to ramp up within several minutes and also meet the capacity requirements of the displaced generation unit (see Figure 2.2). Frequency regulation requires nearly instantaneous ramping to maintain the frequency of the grid at 60 Hz within a controlled error band that is updated by the North American Electric Reliability Corporation Control Performance Standards (NERC CPS2) for every 10 minute period (Kirby, 2004; NERC, 2002). In this market, the grid operator requires either the removal of excess power from the service area when demand for power is low (regulation down, where a PEV providing this resource would charge its battery as normal) or the delivery of additional power when demand is high (regulation up, where a PEV would discharge to the grid) (Masters, 2004; Kempton & Tomić, 2005b; Kirby, 2004).

Ramping time depends on the type of energy storage; conventional turbine power plants that combust coal for power require long ramp up time due to the large amount of momentum needed to rotate the mechanical components, such as a steam turbine, whereas the power stored in batteries is effectively immediately callable. Although the storage that PEV batteries may be able to provide can be adapted to all power markets, in the near term it is best suited to the frequency regulation market (Kempton & Tomić, 2005b). Regulation is seen as a stepping stone on the path to additional storage capacity for renewables.

The frequency regulation market is also the highest compensated of all power markets, making it an optimal market for vehicle participation, both for the grid operators (increased supply of fast ramping power) and the PEV owners (highest potential revenue). Existing suppliers of frequency regulation are compensated for both the actual power delivered (either to or from the grid operator; regulation up or down) and contracting to be available for regulation. Since the power draws required for regulation are small but frequent, the bulk of the compensation comes from the contractual agreement for availability, done on an hour-ahead basis (Hirst & Kirby, 1996). Recently introduced legislation by the Federal Energy Regulatory Commission (FERC) also specifies a pay-for-performance compensation, where regulation providers are compensated for higher ramping capabilities (Federal Energy Regulatory Commission, 2011).

1.4.2 Market Participation Feasibility

Vehicle-Grid Integration (VGI), which is related to the management of this growing sector of increasingly nontrivial power demand, is currently being addressed by stakeholders, such as state public utility commissions, public and private utilities, independent system operators and regional transmission operators (ISOs and RTOs), as well as vehicle and electric

vehicle supply equipment (EVSE, charging station) manufacturers. Although the concerns of VGI are largely related to managing a new demand source (such as through PEV-specific tiered electricity rate schedules that encourage off-peak charging) and ensuring local distribution relays are equipped to handle the additional load, the potential for PEVs to provide ancillary services (such as frequency regulation) to the utilities and ISO/RTOs is a critical thread that has not been overlooked.

This secondary role of PEVs – not just as personal transportation, but as service provider to the utility grid – has been studied at length in the last decade (see Guille & Gross, 2009; Kempton et al., 2009; Bradley et al., 2011; Duan, 2012; Bessa & Matos, 2012; Letendre et al., 2006; Lund & Kempton, 2008; Hutton & Hutton, 2012; Brooks, 2002; Kempton et al., 2001; Kempton & Tomić, 2005b). Initially naming this service Vehicle-to-Grid (V2G), the pioneers of this work anticipated that individual vehicle owners could see a net profit of roughly $2,500 per year by bidding the power in their vehicle into the wholesale frequency regulation power market (typically managed by ISO/RTOs) (Kempton & Tomić, 2005a). Because these initial calculations were so promising, teams of researchers began modeling detailed scenarios for how engagement between vehicle owners and the wholesale market could work, both to explore participation mechanisms, and to refine revenue projections (see Chapter 3 for analysis of these studies). This work was largely conducted in the absence of the technological capabilities to provide bi-directional vehicle battery charging. The equipment necessary to enable V2G – bi-directional charging stations – is now being manufactured for pilot projects that intend to actively coordinate the power resource in their PEVs with grid operators. Proper evaluation of this resource, including its economic viability in the wholesale power market, necessitates the inclusion of these equipment costs and market participation fees in cost-benefit analyses.

1.5 Purpose Of Study

This thesis aims to sew together the salient threads of Vehicle-Grid Integration, especially in the context of the potential for PEVs to begin providing a service to the grid. As the roadmap for this integration is in the process of being developed by stakeholders at all levels, it is important to clarify (1) the need for the new service (Chapter 2), (2) the regulatory and technological boundaries for PEVs to provide this service (Chapters 3 and 4), and (3) the economic practicality of the market niche that has been proposed for PEVs (Chapter 5). This thesis asks the question: Will it be possible to integrate PEVs into the wholesale grid support services market, thereby encouraging CO_2 emissions reductions in both the transportation and electricity production sectors, or will steep market participation fees and infrastructure costs present an obstacle, thereby making it difficult for this emerging potential resource to gain traction beyond the pilot phase?

2 RENEWABLE POWER INTEGRATION AND THE ELECTRICITY GRID

This chapter discusses the policies that aim to motivate the integration of renewable power into the grid mix, and places these policies and alternative power sources in context with an explanation of the current framework for electrical power management. The current framework for power procurement, management, and distribution is optimized for a small portfolio of fossil fuel resources that are both dispatchable on command and generated in large-scale power plants. Existing and proposed policies that mandate the inclusion of renewable sources in the generation of power are only a first (but crucial) step towards reducing domestic CO_2 emissions from the production of electricity. The electrical power system will need to adapt to allow the inclusion of alternative power sources.

2.1 Renewable Energy Inclusion Policies

There are a number of critical policies aimed at developing renewable energy generation capacity. These include, but are not limited to, state and federal tax credits, rebate programs, net metering arrangements, and Renewable Portfolio Standards. The federal investment and production tax credits for corporations have been especially important. The investment tax credits allow corporations to claim investments in solar, fuel cells, small wind turbines, geothermal systems, micro turbines, and combined heat and power at rates between 10% and 30% of expenditures, depending on the resource. The production tax credits allow corporations to claim credits based on the total amount of energy generated from an eligible clean resource, such as wind, closed- and open-loop biomass, geothermal, landfill gas, some hydroelectric, and large marine and hydrokinetic systems (DSIRE-USA, 2014).

One of the most prominent policies for increasing the grid mix of renewable power

are Renewable Portfolio Standards, which are defined and managed by state regulators. A Renewable Portfolio Standard (RPS) defines a timeframe within which a percentage of the state's energy production must come from renewable sources. These standards are motivated in part by the Support Renewable Energy Act, an amendment to the 1978 Public Utility Regulatory Policies Act, which authorized the Secretary of Energy to support regulations at the state level that "allow electric utilities to use renewable energy to comply with any Federal renewable electricity standard" (Support Renewable Energy Act, 2010). As these standards are entirely voluntary on a national level, individual states set their own targets. To motivate compliance, utilities are penalized for failure to achieve these targets.

California was the first state to enact a RPS, and has among the most aggressive standards in the nation. In 2002, the state legislature enacted a standard with a target of 20% renewables by 2017 (Senate Bill 1078), which was accelerated in 2006 under Senate Bill 107 to a new target of 20% by 2010 (Senate Bill 107, 2006). In 2008, the governor signed Executive Order S-14-08, which introduced an additional RPS target of 33% by 2020. The next year, Executive Order S-21-09 directed the California Air Resources Board to adopt the regulations increasing the RPS to 33% by 2020. In the first compliance period after 2010, investor owned utilities (IOUs) must average 20% renewables. As of 2012, the three largest IOUs in California have collectively provided 19.6% of their power from renewable sources (California Renewables Portfolio Standard, 2013).

Although other renewable energy resources, such as small hydro, biomass, and geothermal constitute a large fraction of existing renewable energy generation, wind and solar are the fastest growing renewable resources (Solar Energy Industries Association, 2008). Installed wind capacity is expected it grow from 2.9 TWh to 4.2 TWh to meet the 20% RPS (CAISO, 2010), and installed solar capacity is expected to grow from 1 TWh to 3 TWh. Both wind and solar have low capacity factors, which means that they do not produce power

consistently. Geothermal, biomass, and small hydro all produce power 80% to 90% of the time, whereas wind and solar produce power less than 30% of the time (Kiliccote et al., 2010). Because these sources have such low capacity factors, they cannot immediately replace the power generated from conventional sources. The existing management structure of the grid is not designed to economically accommodate power sources that are both intermittent and have low capacity factors.

2.2 Grid Management

The utility grid is organized to deliver power reliably, and with consistent quality. As there is little storage of electricity on the grid, nearly all power that is generated must also be consumed. The nation is segmented into control areas, which are managed by balancing authorities for each area, usually an Independent System Operator (ISO) or Regional Transmission Organization (RTO). The balancing authority that manages power within California is the California Independent System Operator (CAISO). The balancing authority's role is to match generation with load, and maintain the frequency of the power within a predetermined Area Control Error (ACE).[2]

The procurement of adequate generation to meet load is dominated by the type of load. These are loosely categorized by the time frame over which the load can be reasonably predicted to ensure that the ramp rate of the generation unit (the rate at which power output can change) is matched with the appropriate type of load. Load (demand) can be predicted with reasonable accuracy for long time intervals, but for successively shorter time intervals, prediction of demand must be supplanted by reaction in supply of power. In order

[2]The ACE is defines the limits for scheduled system frequency for a control area, so as not to impose power fluctuations on neighboring areas. It is the sum of the tieline power flow error and the scaled frequency error (Leitermann, 2012, 29).

of decreasing time interval, the most significant loads are base load, peak load, spinning reserves, and frequency regulation.

The existing framework for ensuring the reliable delivery of power for every consumer is largely nested in the management of supply based upon projections for these different time scales. Long time interval markets, such as base load and peak load, are well established, and contracts for each type of generation are secured generally a year in advance; power generators are told to generate at this level based on reasoned prediction of demand.

Base load refers to the minimum threshold of power that is always required (see Figure 2.1). This type of load is flat and regular; large power plants are able to provide the most price competitive electricity. Since this level of demand is consistent, generation that is procured for this purpose is almost always running. Peak load is the demand for power that is variable, but predictable based on daily and seasonal load patterns. For example, peak load will be highest in the summer months during the afternoon, when air conditioning units are most often running. Additional generation to meet these seasonal load variations can be anticipated with high reliability, as balancing authorities have decades of experience forecasting this type of demand (Kiliccote et al., 2010).

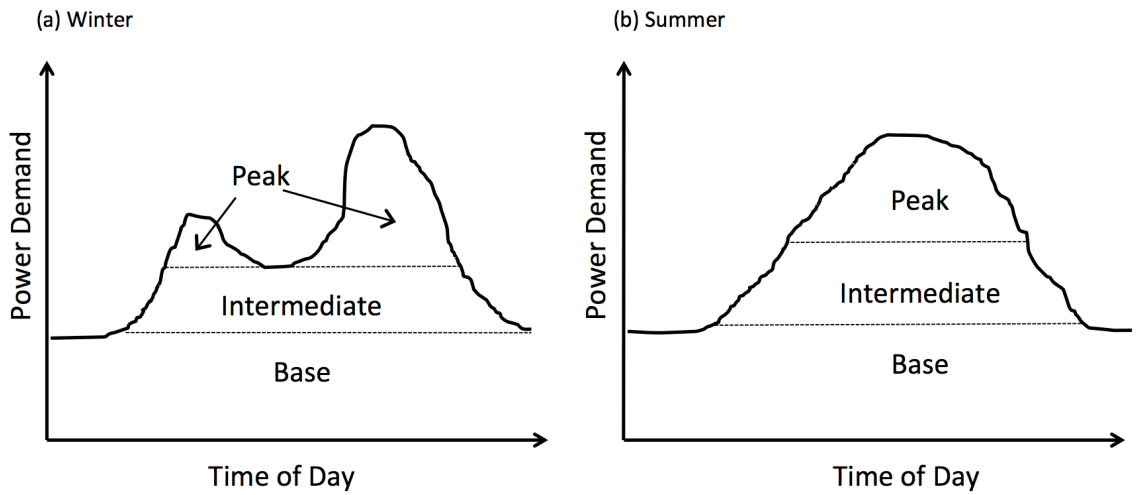

Figure 2.1: Typical day load curve, as percent of daily peak. The difference between winter (a) and summer (b) months is driven largely by increased reliance on air conditioning, and other temperature moderating units, in the summer months. The winter months see a morning and evening peak in power demand that results from shifted power usage over the work- and school-day.

Ancillary services, on the other hand, are secured in the day-ahead and hour-ahead markets. These services command a higher price than the long-term contracts, and regulation and spinning reserves are the most valuable ancillary services (Kempton & Tomić, 2005a; MacDonald et al., 2012).

Spinning reserves and frequency regulation are both ancillary services, which the Federal Energy Regulatory Commission (FERC) defines as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system" (Hirst & Kirby, 1996). Loads and generators are constantly fluctuating; spinning reserves are secured to respond to unanticipated generation equipment failures and imbalances with scheduled generation (see Figure 2.2), and frequency regulation responds to minute-by-minute load variability (see Figure

2.3). Spinning reserves are synchronized to the grid, and the CAISO requires that they respond with the full necessary power output within 10 minutes and sustain that output for a duration of 30 minutes (Kiliccote et al., 2010; Kirby, 2006).

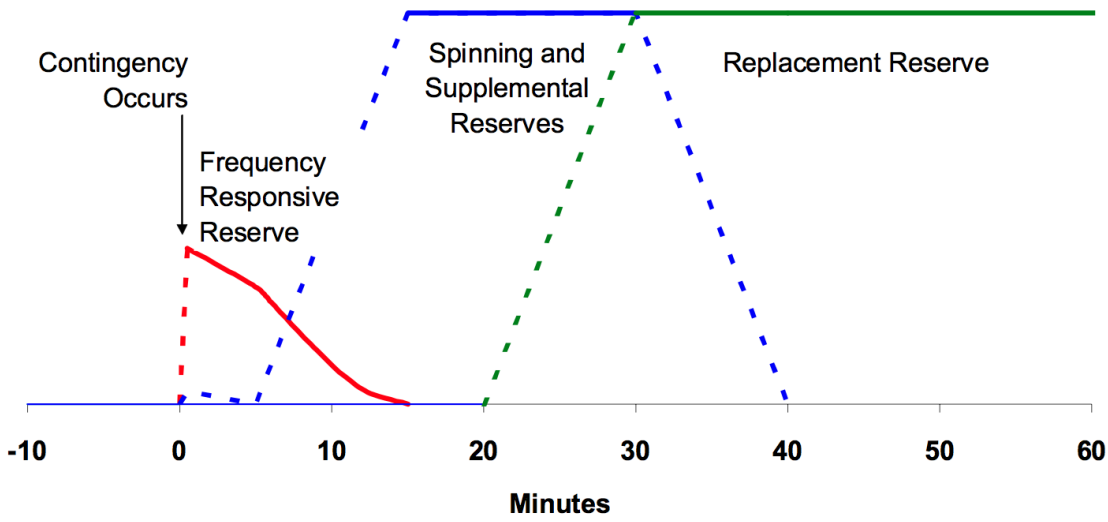

Figure 2.2: Contingency power response as a function of time from outage or imbalance. There are three contingency ancillary services that are necessary to bridge the failure of a generation unit. Frequency regulation must accurately supplant the imbalance immediately, and is replaced by spinning reserves after five to 15 minutes. Spinning reserve responds nearly immediately, and tails off as supplemental, and then replacement reserve comes on-line to restore generation to its scheduled output. Image from Kirby (2004).

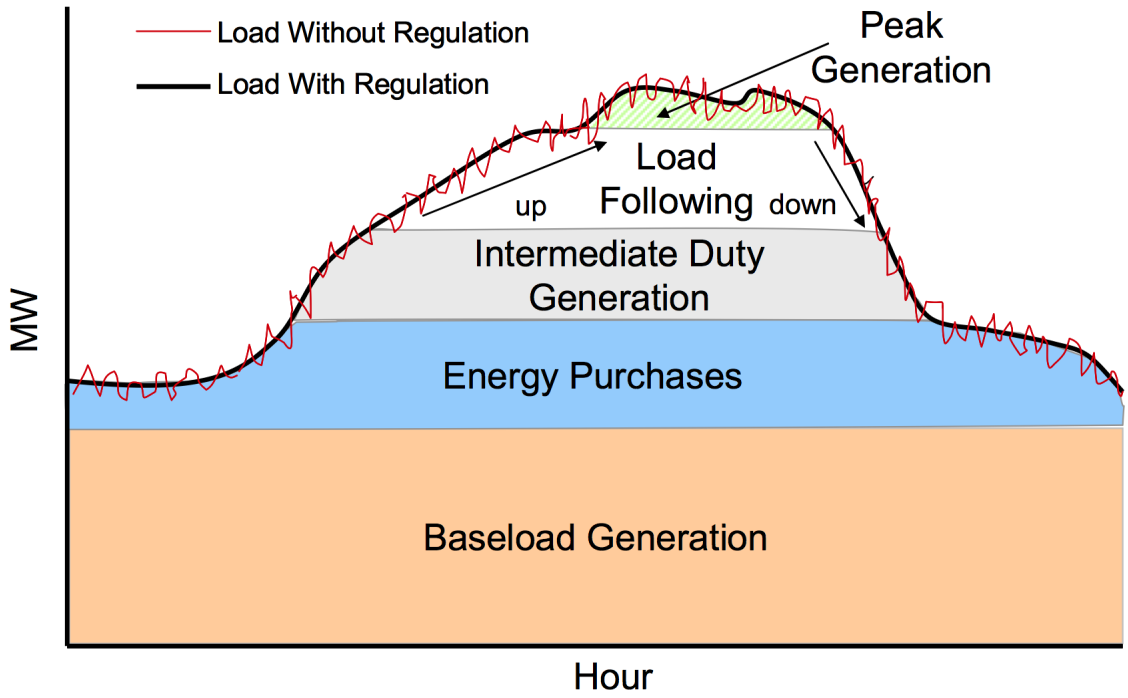

Figure 2.3: Daily load (with and without regulation) as a function of time. The actual system load (red line) can be smoothed with regulation services (the red line load becomes the black line load). Frequency regulation is necessary at all times to regulate the frequency of the grid by filling the small imbalance in power on the system in four second intervals. If the imbalance on the system load is substantial and prolonged, operating reserves such as spinning and non-spinning reserves take over grid stabilizing responsibilities from frequency regulation. Image from Eyer & Corey (2010).

Regulation services were introduced in the mid 1990s to balance load and generation under normal conditions; the frequency of power delivered on the grid deviates from 60 Hz by roughly 0.02 Hz 93% of the time (Hirst & Kirby, 1996). If load exceeds available generation, the generator governor responds by making up the difference with rotational kinetic energy. This slows down the rotational speed of the generator, which in turn lowers the system-wide frequency of power (Leitermann, 2012; von Meier, 2006). System operators, like the CAISO, monitor the frequency fluctuations and ensure that the imbalance remains

within permissible boundaries.[3] If the frequency deviates too much, the system operator dispatches an automatic generation control (AGC) signal to generation units, storage, or loads that are on-line to immediately and quickly change their power output. Frequency regulation is necessary to maintain tieline power flows between control areas at scheduled values, and to minimize the imbalance between generation and load within a control area (Kirby, 2004).

Regulation services are also differentiated from spinning reserves by their response time, and the duration of service. These resources must be already online, and the CAISO requires that they respond within a minute and reach the bid amount within 10-30 minutes. The required duration of frequency regulation is governed by the market in which it was procured. Regulation services contracted in the Day Ahead market are secured for 60 minute intervals, and those in the Real Time market are secured for 15 minute intervals (Kiliccote et al., 2010; Kirby, 2006).

The provision of frequency regulation requires that the generator rapidly respond to an AGC signal when load exceeds generation and when generation exceeds load. In the above example where load exceeds generation, the system-wide frequency of power was forced lower than permissible limits. To correct this, *regulation up* is necessary to bring the frequency back *up* to 60 Hz. When generation exceeds load, the control area's power frequency is forced higher than 60 Hz, and *regulation down* is required. Generators must respond to AGC signals to either increase or decrease their power output to stabilize the frequency of the grid (Kiliccote et al., 2013). Most ISOs procure regulation up and down together and do not compensate generators for supplying one more than the other. The CAISO is an exception; they allow generators to separately contract for regulation up or

[3]These boundaries are defined by NERC under CPS 1 and 2. CPS1 traces the difference between the control area's ACE and the interconnection frequency on a 1-min average basis. CPS2 limits the maximum average ACE for every 10 minute period, averaged over the month (Kirby, 2004; NERC, 2002).

down (MacDonald et al., 2012). In general, the ACE that governs the need for regulation is managed by individual power plants that contract to provide a portion of their power capacity to respond to the AGC (Leitermann, 2012; Prowse et al., 1994).

As a result, large generators play the role of responding to control signals for all time intervals, which has left little internal motivation to incorporate storage into the grid to manage short term power imbalances. Traditional thermal generators have historically been the least-cost approach to providing power for base load and peak load, but they also provide the bulk of the frequency regulation. Although thermal generators can respond to the requirements for regulation, the necessary short ramping rates increase wear, which in turn decrease efficiency. Using traditional generators can also reduce control performance; the fastest signals are filtered out, and if the generators cannot respond, they are neglected (Leitermann, 2012; Douglas et al., 1994).

To address this service deficiency, the FERC issued compliance order number 755 in late 2011, which creates a new revenue stream for fast and slow regulation resources (Federal Energy Regulatory Commission, 2011). Thermal generators still deliver the bulk of frequency regulation services, primarily because there is little precedent for alternatives. Although they are inefficient and sustain wear outside of normal operating conditions, they have remained the least-cost solution for providing regulation within permissible boundaries. The integration of renewable power sources, however, will introduce additional stress on this system, and will necessitate the adaptation of ancillary services power management.

2.3 Challenges For Adapting The Grid For Renewable Power

Polices such as RPSs are paving a political route to include renewable power in the electrical grid mix. The vast majority of this power will be procured from variable sources, such

as wind and solar, necessitating changes in how the wholesale grid is managed (Loutan & Hawkins, 2007).[4] In order to deliver reliable power, utilities and ISOs will need to forecast resource availability in addition to electricity demand, with which they have decades of experience. Forecasting errors of demand are now minimal thanks to this long baseline, but the most reliable day-ahead wind predictions come with 20% error (Kiliccote et al., 2010). Until prediction accuracy of variable resources such as wind reaches that of demand, ISO operations will be dependent on a flexible management structure to accommodate this variability.

The CAISO has identified a handful of challenges for flexible resource management, which highlight the need for electricity storage as well as fast response. Storage is needed to accommodate over-generation (as from forecasting errors from wind), intra-hour variability, and large magnitudes of power ramping, while fast responding units are needed to regulate frequency spikes from instantaneous power ramping (as from solar). Although solar and wind power are, on average, complementary (NERC, 2009), the relatively higher variability of wind to solar creates periods where they are not. When there is insufficient wind to bridge the load until solar power comes online, the ISO will need to replace this gap by dispatching traditional thermal units (Kiliccote et al., 2010, 9).

Insufficient storage capabilities leave little flexibility for variable resources, where high errors in forecasting generation often translate to lost power from over-generation during off-peak hours that could otherwise be shifted to peak periods. High errors in forecasting day-ahead wind generation can also create pockets of congestion on the grid, especially in locations where transmission upgrades intended for renewables generation lag the necessary forecasting accuracy (Hawkins, 2001, 9). Electricity storage can defer or even

[4] An ISO/RTO manages the sale of power on the wholesale market from the generating station to the utility. The utility then sells the power on the retail market to the customer via local lines.

eliminate the need for these comparably expensive upgrades. On shorter time scales, the accuracy of wind generation forecasting becomes comparable with intra-hour load following, necessitating accessible storage in the Hour-Ahead market.[5] Moreover, the CAISO expects a large magnitude of power production ramping as renewables become a more significant fraction of the grid mix. In anticipation of the escalation to 20% renewables by 2010, the CAISO planned for a 50% increase in the 3-hour morning ramp and a 100% increase in the 3-hour evening ramp over three years (Hawkins, 2001, 6).

The escalation to 33% renewables by 2020 will necessitate more dynamic grid management solutions, as base load generation plus the dramatic inclusion of wind and solar will lead to daily periods of over-generation followed by steep load ramping. The CAISO has projected the significant change in power management needs with a graph referred to as the "Duck Chart," shown in Figure 2.4. This graph displays the net load in the CAISO service territory throughout a single day in March, for the years 2013 through 2020. This demonstrates the most extreme scenario for each year, because during the shoulder seasons (March and April in the spring) the solar intensity is relatively high (the solar resource is large), but summer air conditioners are not yet used (demand for power is relatively low) (CAISO, 2014a; Rothleder, 2013).

[5]In the CAISO, the standard deviation of the hour ahead load forecast error is 600 MW to 900 MW (Hawkins, 2001, 7).

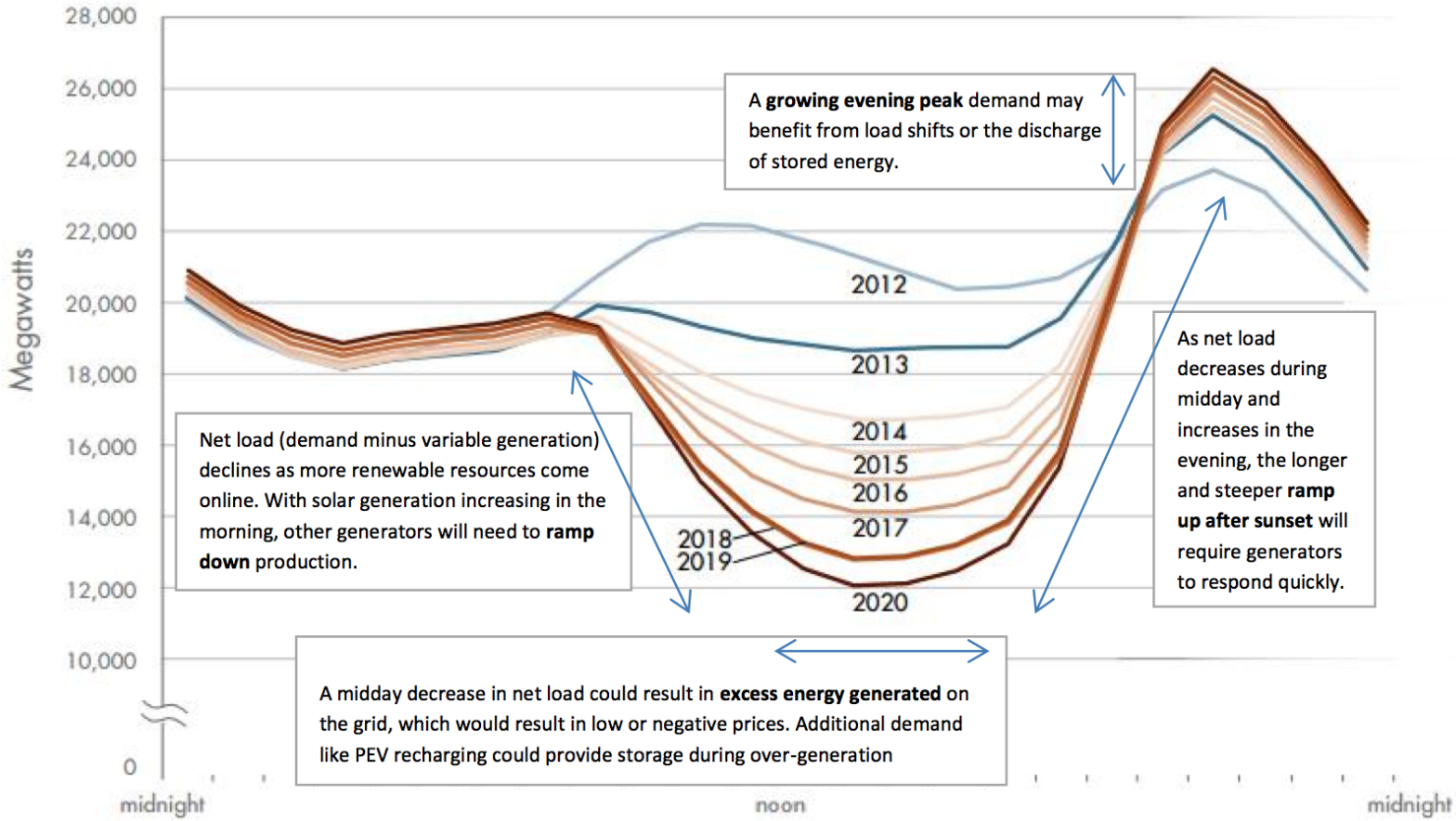

Figure 2.4: Daily net load of a spring day, 2012 through 2020. The rapid inclusion of variable and intermittent renewable power sources within the next decade in California will mean that the needs of the grid will change dramatically. This graph, called the Duck Chart, shows the progressive trend towards the need to address over-generation in the mid-day, and a large ramp in the evening hours to account for an increasingly large evening peak demand. Image from Langton & Crisostomo (2013).

Although each section of the Duck Chart suffers from power management issues (see Figure 2.4), new issues will become exacerbated as the penetration of renewables reaches 33% of the grid mix. The new issues result marginally from wind power and largely from balancing solar power generation with diurnal power demand. The "belly" of the Duck, which begins to shift dramatically in 2015 from increased solar generation, is caused by a steep morning ramp; more solar generation coupled with conventional base load power produces over generation by the early afternoon hours. As solar output falls in the afternoon, the electricity demand begins to peak; this produces a rapid spike in net load (the "neck" of the Duck) for which conventional base load power plants were not built to respond in such a short time interval. A portfolio of solutions ranging from fast-responding to slow-responding power generation adaptations, discussed in Section 2.4, will be necessary to address these changing power management needs in the CAISO service territory (CAISO, 2014a; Rothleder, 2013).

In particular, the CAISO has identified fast response units as a necessary component to flexible renewable electricity management, primarily for the near-instantaneous production ramps. The rapid inclusion of solar, both from distributed and centralized power plants, has the potential to introduce massive levels of power generation to the grid almost instantaneously; solar photovoltaic power generators, unlike thermal and wind units which depend on mechanical rotation to generation power, produce electricity almost immediately.[6] Solar power generators can change their output by $\pm$ 50% within 90 seconds, and by $\pm$ 70% within five to 10 minutes (NERC, 2009). To accommodate fast power production for the 20% RPS, the CAISO projected the regulation ramping requirement to increase by $\pm$ 15 to 25 MW/min (Hawkins, 2001, 7). Existing thermal generators are currently contracted for

[6]The exception to this would be concentrated solar troughs with molten salt, which can take a little while to heat up, and a bit to cool down. This is a crude form of storage. See (Masters, 2004, Ch 4).

this service, but they are easily damaged by fast load fluctuations, even without the addition of these near-instantaneous production ramps (see Leitermann, 2012).

These power management challenges are not insurmountable, but instead illustrate the need for a strategic path for flexible resource management as the fraction of renewable power grows. As of late 2013, Denmark has successfully integrated 33% of its annual average power generation from wind, with the average for December surpassing 50% (Vittrup, 2014). This is largely due to securing energy storage options in cooperation with Germany and Norway. In the near term, the CAISO will first need to address the challenges most relevant to the short time interval power markets, where regulation of the grid's power frequency is most affected.

The path for integrating renewable power is dominated in the near term by the need to address large ramping of power and in the longer term by the eventual need for storage of power for use at a later time. To address these challenges, the CAISO anticipates needing a larger pool of short-term storage for regulation, later to be supplanted by long-term load shifting electricity storage.

2.4 Plans For Adapting The Grid

Balancing authorities will need to adapt their power management capabilities in both the near-term and the long-term to facilitate the introduction of renewable and intermittent power sources. This section discusses how a portfolio of solutions, introduced over the next decade as the needs of the system expand, must be harnessed in order to "Flatten the Duck" (Clean Coalition, 2013).

The CAISO intends to adapt its power management strategies to include additional import/exports, demand response, storage, and forecasting/curtailment. The anticipated

result of “intelligent grid” solutions is shown in Figure 2.5, where the dotted red line is the original Duck Net Load, and the solid red line is the Flattened Duck Net Load from the inclusion of these new strategies (Clean Coalition, 2013). Import/exports are beginning to play a key role in the form of Energy Imbalance Markets (EIMs); for example, the CAISO and Pacificorp have recently reached an agreement where the CAISO will purchase power generated from large hydro to offset base load power during key hours of the day (Trabish, 2013). The CAISO will benefit from EIMs with other balancing authorities that have lower wind and solar penetration, and those that are in different time zones and can offset hourly demands. Demand response (DR), discussed below, incentives customers to reduce power consumption during peak demand periods. PEVs may be able to provide both distributed energy storage as well as load shifting/DR services, in order to address the 1.3 GW of storage needed. Increased accuracy in forecasting wind intensity will allow grid operators to curtail generation and flatten the afternoon ramp (Clean Coalition, 2013). The most pressing issue is to address instantaneous ramping demands, which can only be solved with a larger pool of fast-responding regulation resources.

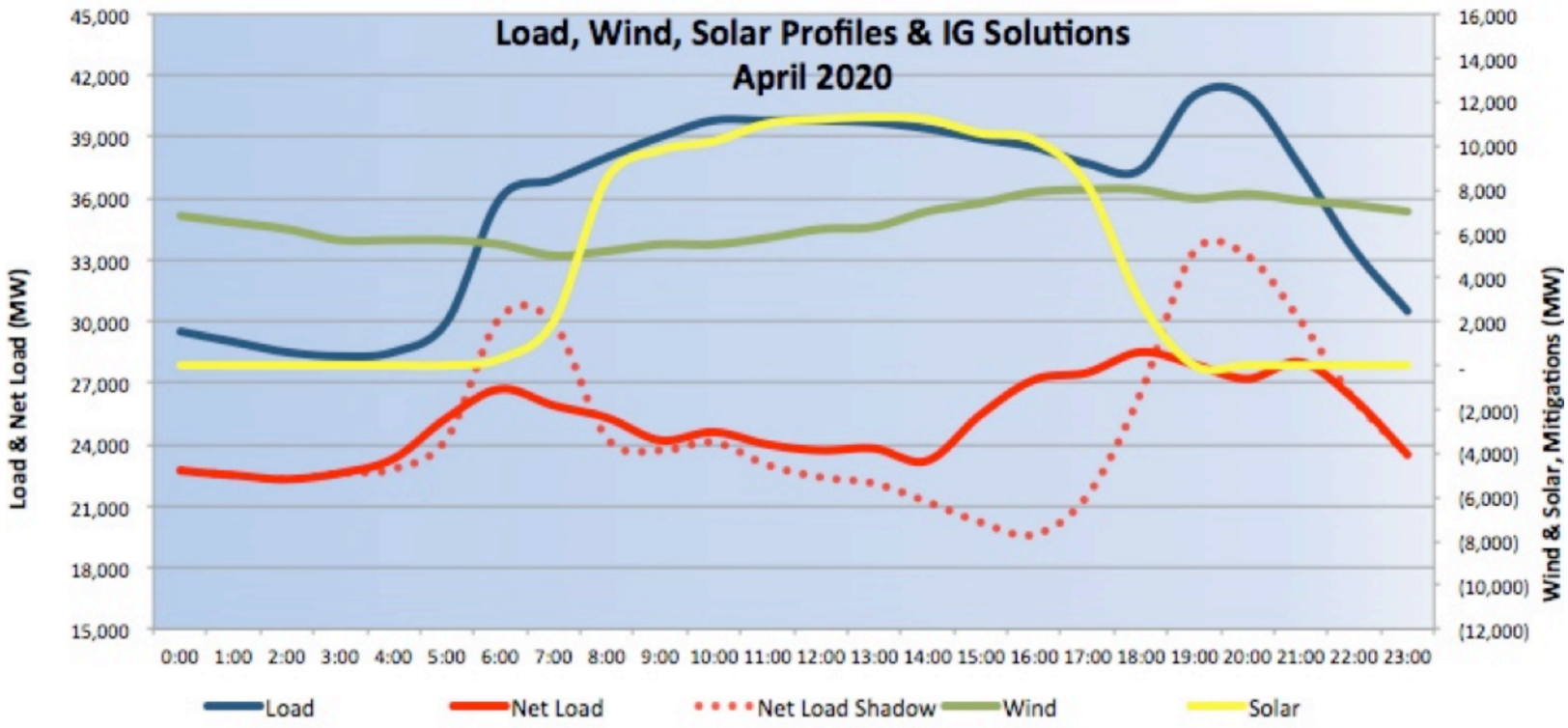

Figure 2.5: Daily net load in April 2020 and the power sources that contribute to the "duck" shape. The Duck Chart can be flattened to the net load seen in this graph (red solid line) with a portfolio of solutions. The original Duck Net Load (dotted red line) is the summation of the system load (blue line), wind resource (green) and solar resources (yellow). By 2020, this can be remedied by including "intelligent grid" solutions such as demand response, energy storage, energy imports and exports, such as from Energy Imbalance Markets, and curtailment. Image from Clean Coalition (2013).

The most tractable path for addressing the near-term challenge of fast ramp rates and the long-term challenge of large magnitudes of power load-shifting is flexible grid-connected storage that is both immediately accessible by grid operators and can easily grow in capacity. The power market where the near-term challenges will be most apparent is ancillary services. To ease the strain on this market, the FERC passed Order 755, which compensates fast-response service providers at a premium over traditional providers. Regulation services are already the highest compensated market on average; this order facilitates the entry of small-scale rapid response storage units into the California power markets.

Fast ramp rates introduced by intermittent renewable power sources will have the largest impact on the frequency regulation market. Two underutilized resources can help mitigate the impending strain on this market: demand response (DR) and vehicle-to-grid or battery-to-grid (V2G). DR involves price-based and reliability-based load curtailment from buildings, whereas V2G introduces the potential for a growing cache of electricity storage in distributed batteries (Kiliccote et al., 2010, 10).

DR as a form of energy storage has been shown to successfully mitigate the spikes in grid frequency introduced by wind variability by managing the loads of both residential buildings as well as commercial and industrial facilities (Callaway, 2009; Kiliccote et al., 2010). The California utility PG&E has also offered several DR programs since late 2010. Studies from these pilot programs have shown that the large commercial and industrial facilities are particularly suited to provide ancillary services, as they already have advanced control systems that can automatically respond to control and price signals from the CAISO (Kiliccote et al., 2010, 11).

Although the primary application of DR has historically been to shift peak loads, motivated primarily with day-ahead dynamic pricing (FERC, 2006; Kiliccote et al., 2010), recent technical feasibility studies of DR for ancillary services have illustrated the critical

role of automated communications with the ISO. These studies have shown that commercial and industrial buildings, by either increasing or decreasing loads from HVAC and lighting, can achieve a ramp rate of 0.25 MW/min, and respond to this signal from the CAISO within 47 seconds (Kiliccote et al., 2010, 14).

The ability to respond to the ISO's ACE signal on sub-minute timescales is paramount. Field tests of DR by the Lawrence Berkeley National Laboratory (LBNL) have equipped building control systems with an OpenADR (Automated Demand Response) client that can meet these communication speed requirements by converting the signal from the ISO into an AGC signal, as for traditional regulation-contracted generators. Results show that converting the AGC signal into an OpenADR signal that the building control system can interpret does not significantly reduce response times. Controlling the loads in buildings for regulation is typically contracted in the day-ahead market; lack of accuracy in load forecasting remains a significant barrier to DR participation by building operators (Kiliccote et al., 2013).

The advancements made in these technical feasibility and field test studies highlight the need for both controlled loads, and distributed flexible power storage. While DR can address the former, PEVs may prove a key tool in flexible power storage; the mechanisms for this integration are discussed in Chapter 3. Whether or not PEVs are integrated into the grid to help address storage issues, flexible power storage will become a necessary component to addressing the challenges outlined in Section 2.3. Although batteries have historically been cost-prohibitive for utilities as storage (von Meier, 2006), global utility-scale energy storage from newly installed advanced batteries is expected to grow 48.1% annually over the next decade (Jaffe & Adamson, 2014). More locally, the California utility Pacific Gas and Electric (PG&E) installed a four MW capacity sodium-sulfer battery storage plant as a pilot project in early 2013, largely aided by a grant from the California

Energy Commission (PG&E, 2013).

What should be made clear by this section is the glaring need for regulations and funding sources that facilitate the inclusion of flexible grid management resources. The following section outlines the recent policies that directly aim to accelerate the accessibility of these resources to the grid operator, especially as they apply to the integration of PEVs with the grid.

2.5 New Regulations To Aid Flexible Resources

In order to address the challenges outlined in Section 2.3, legislators have been busy drafting, passing, and enacting new regulations that will both ease the transition for renewable and intermittent resources into the grid, and level the wholesale market competition barriers for the small and distributed resources that are best suited to make this possible (see also Hutton & Hutton, 2012; Lamble, 2011; Sioshansi et al., 2012). Table 2.1 describes the most relevant policies that are paving the way for PEVs – as a distributed battery storage resource – to integrate with existing grid services.

Table 2.1: Relevant policies that will aid Vehicle-Grid Integration. Policies originally printed in (CAISO, 2013), unless otherwise cited.

Policy	Entity	Description and Relevance
Federal Energy Regulatory Commission Order No. 719 (Federal Energy Regulatory Commission, 2008; Bushnell et al., 2009)	FERC	• Expands wholesale competition in regions with organized electric markets • Requires ISO/RTOs to accept bids from demand-side resources for ancillary services, where comparable to other resources

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Table 2.1 – Continued

Policy	Entity	Description and Relevance
Federal Energy Regulatory Commission Order No. 755 (Federal Energy Regulatory Commission, 2011)	FERC	• Compensates market participants for mileage of response • Creates opportunity for increased pay for fast responders like batteries
Federal Energy Regulatory Commission Order No. 764 (Federal Energy Regulatory Commission, 2012)	FERC	• Introduces 15-minute scheduling option in real-time market for variable resources • Intended to reduce barriers to integration of variable energy resources
Federal Energy Regulatory Commission Order No. 784 (Federal Energy Regulatory Commission, 2013)	FERC	• Expands FERC 755 pay-for-performance requirements to account for speed and accuracy • Applies new accounting practices to track energy storage; potentially affects payment for VGI services, depending on VGI capabilities
Federal Energy Regulatory Commission Order No. 792	FERC	• Adjusts the Small Generator Interconnection Procedures (SGIP) and Small Generator Interconnection Agreement (SGIA) for generating facilities no larger than 20 MW • Will shape interconnection associated with storage devices
Standard ISO/IEC 15118	ISO/IEC	• Creates a global standardization of communication interface • Will likely shape VGI enabling technologies
Standard SAE J1772	SAE	• Establishes a recommended practice for EVSE • Will likely shape VGI enabling technologies

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Table 2.1 – Continued

Policy	Entity	Description and Relevance
Assembly Bill (AB) 2514 (Assembly Bill 2514, 2010) and CPUC Storage Proceeding Docket No. R. 10-12-007	CPUC	• Each load-serving entity must adopt an energy storage system procurement target, achievable by Dec 31, 2015 • States that EV capacity can contribute to the storage procurement targets • Potentially creates demand for VGI services, depending on how VGI compares to other options
Resource Adequacy (RA) Proceeding	CPUC	• Guides the resource procurement process and promotes infrastructure investment by requiring LSEs to provide capacity as needed by California ISO • Potentially influences demand for VGI services, depending on VGI capability to meet RA needs
Energy Storage Procurement (D.13-10-040) (CPUC, 2013)	CPUC	• Sets a target of 1,325 MW of storage by 2020 • Of this, 200 MW must come from resources "behind the customer meter," such as PEVs
Demand Response (DR) Proceedings Docket No. R.07-01-041	CPUC	• Reviews and analyzes demand response to assess its potential role in meeting the state's energy needs • Potentially serves as a platform for clarifying rules about how EV may participate in DR
Rule 24 DR Direct Participation	CPUC	• Determines how customers might "directly participate" in, or bid services directly into, the wholesale market. • Potentially influences the process by which VGI services can offer wholesale market services.

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Table 2.1 – Continued

Policy	Entity	Description and Relevance
Rule 21 Interconnection and Net-metering (Docket No. R.11-09-011)	CPUC	• Describes the interconnection, operating and metering requirements for generation facilities of various sizes to be connected to a utility's distribution system, over which the CPUC has jurisdiction. • May influence the interconnection requirements around VGI, where two-way power flows are possible
Wholesale Distribution Access Tariff (Docket No. ER11-2977-000)	CPUC	• Defines the tariffs architecture of energy transfer between California ISO and utilities or customers • Guides a portion of VGI payment processes
EV Proceedings	CPUC	• Addresses barriers to widespread EV adoption, on which the VGI market is dependent • Promotes communication among EV stakeholders, including those involved in VGI • Addresses EV sub-metering issues, which could influence VGI payment processes
Smart Grid Proceeding (Docket No. R.08-12-009)	CPUC	• Establishes standards, protocols, and policies which will affect Smart Grid programs and strategies, such as VGI

This chapter discussed the existing power procurement and delivery framework for the electricity grid, and introduced the challenges that will be seen as renewable resources, especially wind and solar, reach high levels of penetration into the grid mix, such as the RPS of 33% renewables by 2020 in California. In the long term, extreme accommodations from storage, enhanced forecasting and generation curtailment, and demand-side load shifting will be needed to meet the demands of flexible generation sources. In the near term,

however, small storage resources, such as traditional battery banks, demand response, and PEVs, are well-suited to take the role of the first step in this integration process. PEVs in particular are beginning to present themselves as a previously untapped, and growing, resource, so long as their integration with the grid is optimized for both personal transportation as well as system-wide power management. The following chapter describes Vehicle-Grid Integration, and discusses how state legislators and other stakeholders intend for it to function in theory.

3 WHAT IS VEHICLE-GRID INTEGRATION?

The growing need for flexible grid-tied storage, along with the increasing number of regulations aimed at facilitating the inclusion of these resources, suggests that PEVs may be well-suited to fill this niche, even when market penetration levels are low. The frequency regulation market – one of several ancillary services – is the most appropriate entry market for PEVs for a handful of reasons: (1) it is the highest compensated market, accounting for 80% of all ancillary service costs and nearly 10% of all electricity costs (Kempton & Tomić, 2005a); (2) PEVs are capable of responding to even the fastest grid operator signal, making them both flexible for use in multiple markets and capable of bidding into the highest compensated markets (Brooks, 2001); (3) the new Pay-for-Performance FERC Order 755 will create additional revenue potential for fast-responding regulation providers, such as PEVs.

Although the frequency regulation market is small relative to other ancillary services, at about 1% of total load, most studies suggest that it will be a vital stepping stone to more wide-spread integration of PEVs into the power market. Even during peak summer load, the demand for this niche service is roughly 500 MW statewide, meaning that only 30,000 PEVs would saturate the market at peak times and likely half of that during non-peak times (Makarov et al., 2009; MacDonald, 2013). In anticipation of both frequency regulation market saturation and a marked increase in PEV sales over the next decade, many analyses also calculate the revenue potentials from load shifting, spinning reserves, and other lower revenue markets (see Bessa & Matos, 2012).

This chapter describes potential pathways for PEVs to integrate with the power grid with the intent to generate revenue by storing power in their batteries, including proposed aggregation scenarios meant to counteract the effect of individual PEVs disconnecting from

the grid. There are two broad questions that must be addressed in order to make this a reality: (1) Where will the revenue come from (e.g., traditional power market, personal load offset/netmeter)? and (2) If this revenue source requires aggregation of PEVs for participation, how will they be aggregated? Although the analysis in this work draws from the frequency regulation market (see Chapter 5), this chapter illustrates both the landscape of possible revenue/aggregation configurations and the anticipated trajectory for increasing complexity of VGI.

3.1 Potential Vehicle-Grid Integration Configurations

Vehicle-Grid Integration describes the spectrum of integration issues that will need to be addressed as the interactions between the two become more complex. The least complex scenario is the one with which most are already familiar: the PEV battery is charged from the grid, usually at a home location. The most complex scenario for which grid operators, utilities, and state regulators are currently preparing is V2G, where the PEV battery both pulls power from, and pushes it to the grid depending on need. The California Public Utilities Commission (CPUC) has organized the management of power between vehicles and the grid into four main categories (see Figure 3.1). Since the CPUC regulates how utilities manage power, this organization structure has been adopted by other agencies, including public utilities and the CAISO, for simplicity of dialogue concerning VGI.

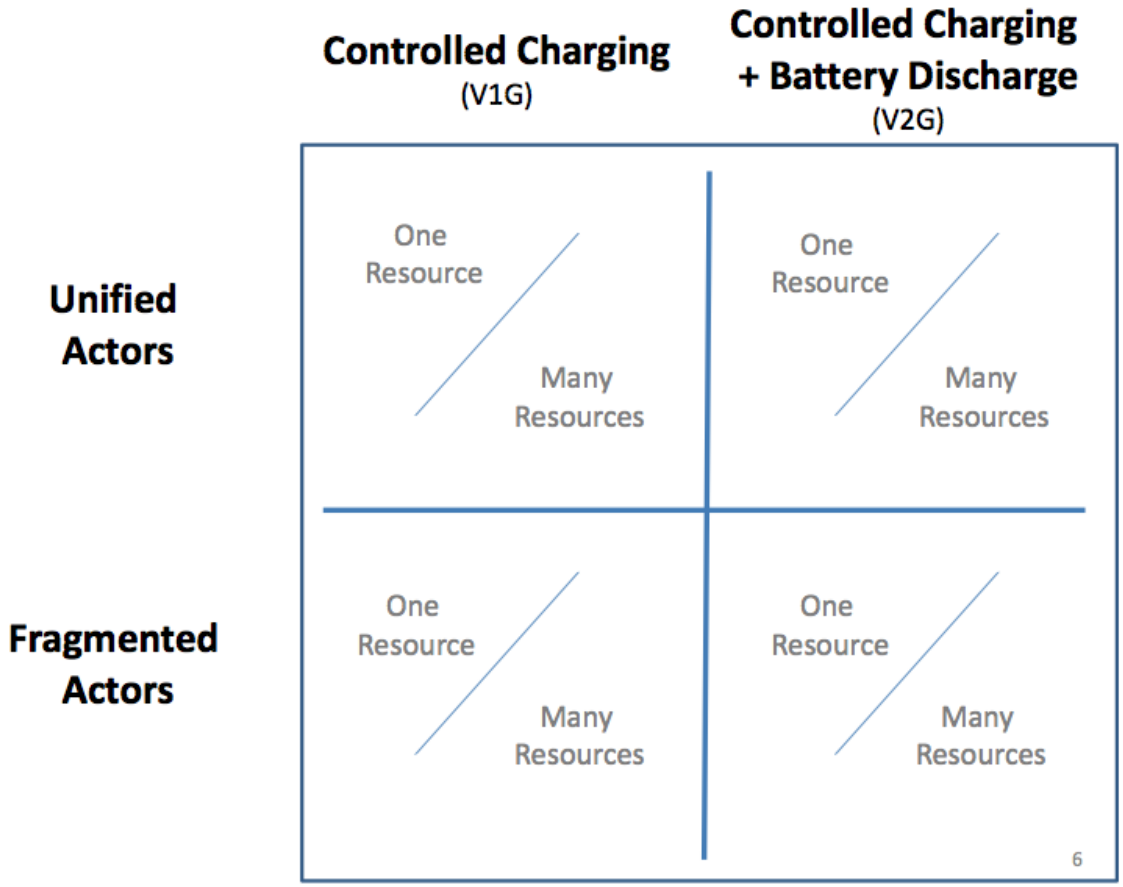

Figure 3.1: Possible categories of Vehicle-Grid Integration, as envisioned by the California Public Utilities Commission, and used in the VGI Roadmap. Image from Langton (2013b).

There are three categories that define the management of power between a PEV and the grid where the power flow is controlled by someone other than the vehicle's on-board charger: (1) one-directional (V1G) or bi-directional (V2G) charging, (2) one "resource" (vehicle) versus many resources, and (3) unified versus fragmented actors. In the first category, V1G versus V2G, the power may flow from the grid to the vehicle only (V1G), or equally between the two (V2G). The defining difference between V1G and V2G is that, over a typical market bid period of one hour, the battery slowly gains power on average in V1G mode, whereas in V2G, the average power is roughly zero (see Figure 3.2). For

example, with a PEV that has an on-board charger of 6.6 kW,[7] a third party controls the charge rate between 0 kW and 6.6 kW, and the PEV charges at an average rate of roughly 3.3 kW (Figure 3.2, left). With controlled charging and battery discharge (V2G), a third party can control the charging and discharging of a PEV battery. For a 6.6 kW PEV battery, the charging speed will range from -6.6 kW (discharge battery at maximum rate) to 6.6 kW (charge at maximum rate). In practice, during the one hour bid period the PEV will, on average, neither charge nor discharge while providing this service.

[7]The charging speed between a PEV and the grid is the minimum rating between the on-board charger, the connection plug between the vehicle and the EVSE, and the EVSE. Most PEV on-board chargers are rated at 3.3 kW or 6.6 kW. The SAE J1772 standard plug can provide power at up to 19.2 kW, and most commercially available Level 2 EVSE are rated at 7.2 kW (SAE International, 2011; Alternative Fuels Data Center, 2014). With an on-board charger rated at 6.6 kW, a plug rated at 19.2 kW, and an EVSE rated at 7.2 kW, the maximum charging speed between the PEV and the grid will be 6.6 kW.

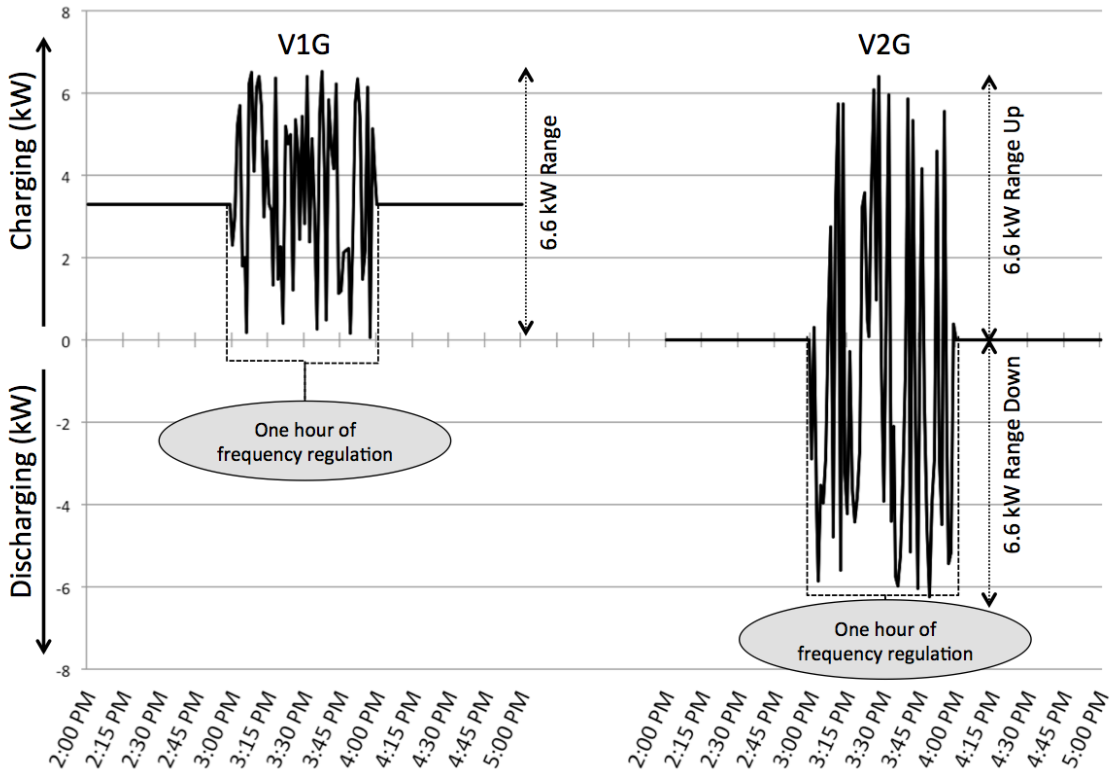

Figure 3.2: Available power ranges for a PEV in V1G (charge only) and V2G (charge and discharge) for one hour of frequency regulation. The available power range for a PEV with an on-board charging capacity of 6.6 kW is different in V1G and V2G. In V1G (left), the PEV charges its battery at a rate between 0 and 6.6 kW; on average, the charge rate is 3.3 kW. In V2G (right), the PEV can either charge the battery between 0 and 6.6 kW, or discharge the battery between -6.6 and 0 kW; on average, the charge rate is 0 kW.

In the second category, the "resource" can be loosely defined as the available power in a vehicle's battery. Conventionally, the resource is the PEV. Since both V1G and V2G require the vehicle to allow charging by an entity that is not the on-board charger, that entity can also control the charging schemes for multiple PEVs. In most cases, the charge controlling entity will be the grid operator, and the charging scheme will be influenced by the AGC signal (see Chapter 2). In order to participate in the appropriate power market, many PEVs may need to be aggregated to comply with minimum power regulations. Other

scenarios, such as integrating a personal PEV into a residential net metering arrangement, may allow for a single resource to successfully provide a V1G or V2G service.

The third category, unified versus fragmented actors, refers to the ownership of the PEVs that enter into a contract with a single external charge controlling agent. A fleet operator who owns multiple PEVs may, for example, contract with a grid operator to provide power services from the fleet of PEVs in bulk. This resource is aggregated by the owner, and the owner of the resource is typically the same entity that contracts with the grid operator. Fragmented actors may be individual PEV owners who wish to enter into a contract with a grid operator to supply V1G/V2G services by being aggregated with other individual PEV owners. Fragmented actors typically cannot contract directly with the grid operator due to minimum power requirements of the power service.

The chart in Figure 3.1 loosely defines a roadmap for Vehicle-Grid Integration, where the power flow to the battery is controlled by someone other than the on-board charger, as a function of the natural progression of complexity. The first step, shown in Figure 3.3, will be V1G for one resource, which is also a unified actor. There are two existing possibilities for this step: one which allows the PEV to be controlled by a grid operator, and one that is islanded from the grid. In the first, the PEV is integrated with a residential unit net metering contract, where the PEV may either help offset high household electricity consumption in partnership with a larger solar array than would normally be recommended for a net metering contract (Senate Bill 153, 2009), or the PEV may help offset the total monthly fees based on how much frequency the grid operator needs to push excess power to V1G-net metering eligible units. In the second, the PEV is islanded from the grid and serves as a battery backup to a home solar system. The second possibility, also called V2B or V2H (building or home) will see fewer regulatory hurdles, because it is currently against California regulations to integrate a battery backup unit with the utility grid (St.

John, 2014). The largest challenge of this step is enabling an external agent to control the charge scheme of the PEV battery.

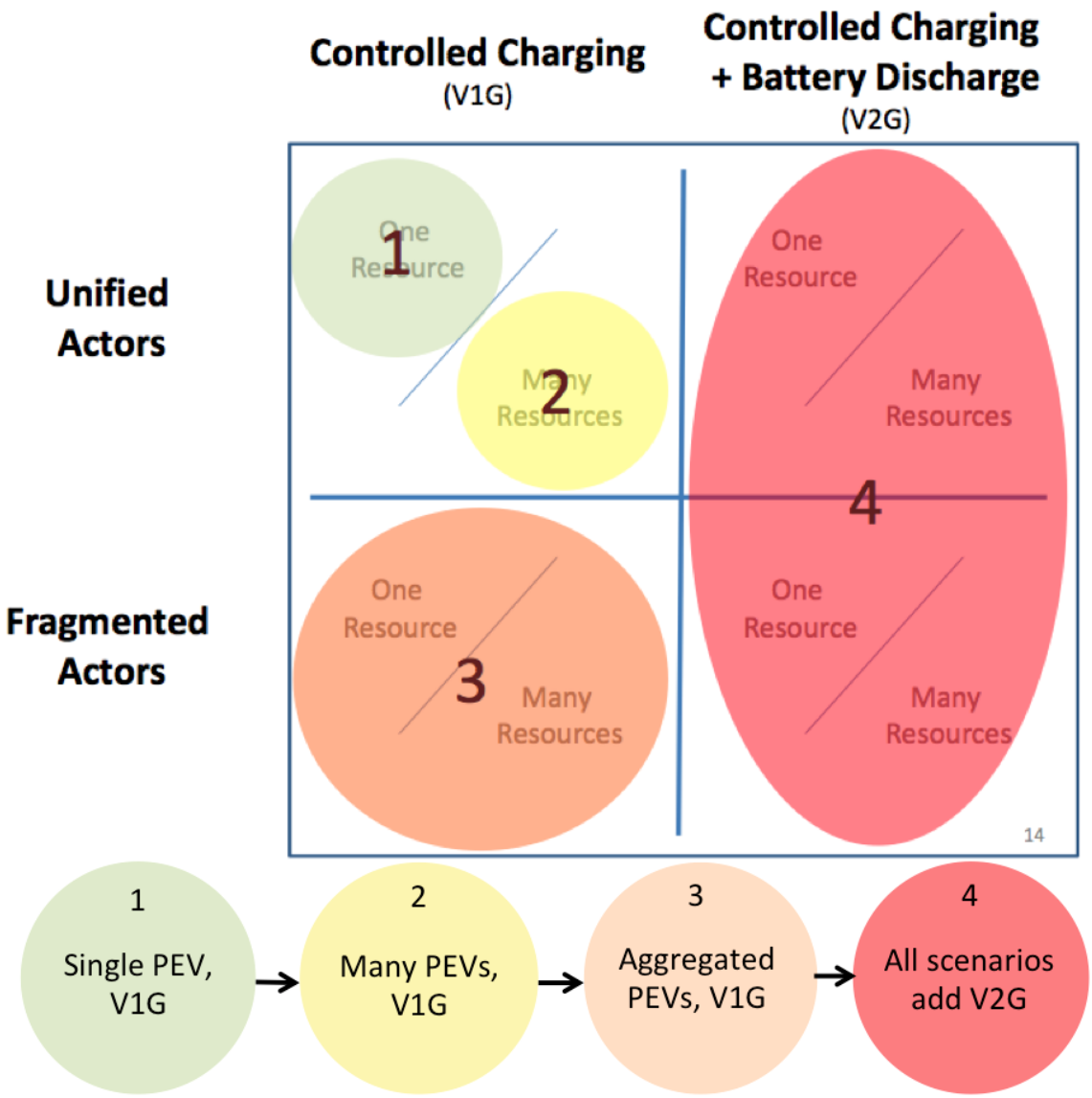

Figure 3.3: Four progressive steps to Vehicle-Grid Integration. The CPUC has recommended that VGI progress in four steps, loosely organized by the categories from Figure 3.1. Step 1: Controlled charging (V1G) of one resource through a unified actor – one PEV participating in the market alone, where the grid operator controls the charge rate. Step 2: Controlled charging (V1G) of many resources through a unified actor – a fleet of PEVs, unified by one manager, participates in the market by allowing the charge rate of each vehicle to be controlled by the grid operator. Step 3: Controlled charging (V1G) of many and/or one resources through fragmented actors – aggregation of multiple, separated PEVs, is necessary. Step 4: All previous scenarios also incorporate controlled charging and battery discharge (V2G). Original image from Langton (2013b).

The second step on the road to integrating PEVs with the grid will be many resources that are unified by one owner and operated under controlled single-directional charging (V1G). The details of this step are currently being developed with computer simulations (see Section 3.2.1 later in this chapter) and by PEV fleet pilot projects. This step is crucial for development of the following step, because its largest challenges are managing the interaction of multiple resources with one power demand signal (which resource is dispatched, and when) and developing specifications for the technologies that will allow PEV resources to respond to a grid operator's signal, such as telemetry requirements specific to a resource that is unified, but aggregated.

The third step, and the next level of complexity, will be to integrate fragmented actors into an externally controlled charging regime. Whereas in the second step the actors are largely PEV fleets (single owner/operator of vehicles), this constraint is not necessary for the third step. The largest challenge of this step will lie in determining an appropriate aggregation scheme. For fragmented actors, aggregation will be compulsory in order to meet the minimum wholesale participation requirements. Many aggregation configurations have been proposed, including dedicated V1G/V2G parking garages (where the "resource" in each vehicle's battery is aggregated by the garage coordinator, a third party actor), and intermediary aggregators, such as a utility or other third party (Guille & Gross, 2009; Brooks & Gage, 2001). A more detailed consideration of aggregation schemes is presented in Section 3.2.1 later in this chapter.

The final step to integrating vehicle-grid interactions will be coordinated bi-directional charging (V2G) for all actors and resources. The challenges to this step will be the development of telemetry and communications infrastructure that can handle distributed non-generating resources, and hardware, such as charging stations, that is designed to manage the flow of power to and from a PEV (California ISO, 2012, 2013). Prototypes of the de-

vices needed to meet these new infrastructure requirements are currently being developed for V2G pilot projects (See Section 4.3). Although the prototypes for this application are not yet commercially available, cost estimates for these devices may be estimated from other products that perform similar services, such as grid-tied inverters that can manage power delivery to and from the grid. The fourth step also considers full participation in the wholesale market.

From the perspective of the grid operator (who also manages the wholesale market), the defining progression of complexity for VGI is dominated by the management of the stored power in the PEVs, and whether this power comes from unified or fragmented actors. Although the grid operator will benefit from the inclusion of additional power storage, it does not manage power below the granularity of the ISO meter. Participation in the ISO wholesale market requires, in part, the installation of a unique ISO meter that tracks the power flow from a unique resource point.[8] Unified actors, such as a fleet operator, require only one ISO meter; the grid operator is thus assured that the power resource behind this meter will meet the minimum requirements for the wholesale market. Fragmented actors, such as individual PEV owners that are virtually aggregated by a third party each require their own ISO meter; the grid operator will need to coordinate with the third party power aggregator.

3.2 Current Technology Research: How To Optimize Power Give And Take

This section discusses the progression of research into V1G/V2G, including an explanation of the payment structure for the frequency regulation market, suggestions for virtual aggregation coordination, and computer simulation analyses for both controlled charging (steps

[8] In general, the ISO meter is situated at a power generation facility. PEVs that participate in V1G/V2G, however, are referred to as Non-Generating Resources.

1, 2, and 3 in Figure 3.3), and controlled charging/discharging (step 4).

Although there are a handful of other applications for which controlling the power in PEVs will be a useful resource, this analysis addresses the challenges and requirements of providing frequency regulation on the CAISO wholesale market (Langton & Crisostomo, 2013). As mentioned previously, the primary motivation to begin with this market is the high payment for the resource, relative to other mechanisms. In line with this, most pilot projects of V1G and V2G address the complications of participation in this market as a baseline.[9]

PEVs that enter into a contract to provide frequency regulation with the wholesale ISO market are guaranteed three mechanisms of payment: (1) availability for blocks of one hour, regardless of power draws, (2) actual net power draws within a five minute window (see Goebel & Callaway, 2013), and (3) the performance (or quality) of the power draw, also called "Pay for Performance" (Federal Energy Regulatory Commission, 2011). In the CAISO service territory, wholesale market participants may contract for regulation up individually from regulation down. The payment for reserving power capacity is determined based on the Megawatts (MW) that are bid into the system (or "reserved" by the PEV operator) in one hour segments, or MW-hs.[10] This reserved capacity payment is the primary revenue stream for participants in this market, as actual net power draws (both regulation up and down) are minimal by nature. "Pay for Performance" was initiated in late 2013 as a result of FERC Order 755, which aims to preferentially compensate fast-responding resources like PEVs. Due to the short baseline of this revenue stream, and the relatively minimal payments for actual power draws, most analyses only consider revenue from the

[9]Some studies look at frequency regulation market and other mechanisms (see Kempton et al., 2001; Turton & Moura, 2008; Kempton & Tomić, 2005b; Hawkins, 2001; Brooks, 2002). Only a few look at other mechanisms (see Kempton & Letendre, 1997; Brooks & Gage, 2001; Fell et al., 2010).

[10]Note that this unit, MW-h, is a unit of reserved power for an hour, not a unit of energy.

reserve capacity mechanism, or payment per MW-h.[11] Since the primary revenue stream for participation in the wholesale frequency regulation market is based on hourly capacity contracts, most analyses limit their business cases to this revenue source.

To this end, PEV resource aggregation scenarios must provide a business case where the interests of each party are met and they must meet the minimum requirements of the entrants. These limits, as recognized by a study done for the ISO/RTO Council (IRC) require that an aggregator "coordinate the application of multiple EVs to meet product or service commitments to the ISO/RTO while also achieving targeted charge levels per commitments to the vehicles ... an aggregator will need to sign up a sufficient number of EVs to provide the product or service and meet requirements specified by the ISO/RTO to participate in the market" (Fell et al., 2010).

The first step on the path to VGI presented by the CPUC, controlled charging of a single unit (Figure 3.3), is the only scenario that does not imply the use of aggregation – a "direct architecture" (Bessa & Matos, 2012, 343). Although a PEV may contract for V1G services in a direct architecture in principle, Quinn et al. (2010) were among the first to show that this direct architecture is less reliable for the grid operator, since the PEV may either be unavailable for extended periods of the day, or controlled charging of a single PEV may lead to a prematurely charged or discharged battery with respect to system need (Kempton et al., 2009). From the perspective of a grid operator, the aggregation of resources (whether physical with a fleet of PEVs, or virtual with fragmented actors) guarantees the availability of resources at any time they may be needed. Aggregation also helps to improve the response to the AGC, and in turn the behavior of system dynamics (Almeida et al., 2010).

[11] In addition, the capacity payment ($/MW-h) is variable daily, seasonally, and over the past 10 years (see MacDonald et al., 2012). See Section 4.4.

The challenge to the aggregator, then, lies in coordinating the needs of multiple PEVs (and potentially different owners) with those of the grid operator. The following subsections describe several proposed optimization algorithms for power management and the business cases that correspond to different aggregation strategies.

3.2.1 Algorithms

Much work has been done in the last decade to determine the optimal coordination of controlled charging and discharging requested by an aggregator of PEVs. Some researchers focused on determining the dominant variables, while others focused on the theoretical limits for a "best case" statistical optimization of resources.

The initial concept of an aggregator was introduced by Kempton et al. (2001) because of the fact that an individual PEV owner, with a kW-scale power capacity, could not bid into the MW-scale wholesale frequency regulation market on his or her own. When looking at two PEV fleet scenarios, Tomić and Kempton determined that, in order to maximize profit for the aggregated PEV owners, information about either the forecasted revenue for the market or the anticipated number of participants was compulsory (2007). As one of the first analyses in this subject, this group determined that the dominant variables were the actual price for the hourly contract service (in $/MW-h), the power capacity of each PEV's connection to the grid (in kW), and the total storage capacity of the battery (in kWh).

The difficulty in coordinating the power vested in a constantly shifting number of distributed sources (fragmented actors) is that the highest priority for the PEV is the transportation it provides to the owner; services to the power grid must be secondary. To meet this fundamental requirement, Brooks and Gage initiated the idea of a "virtual power plant" wherein all PEV owners communicate their time commitments to the aggregator, who can

then forecast with greater flexibility the availability of power resources (2001). The authors were the first to note that the aggregation of multiple PEVs allows for more certainty in forecasting the availability of this resource than that of a single PEV.

Another study, led by Clement-Nyns et al. (2010), revealed the crucial role that the PEV owner plays in communicating the time when the vehicle is needed for personal use and the state of charge needed. They also note the fact that allowing uncoordinated charging (controlled or uncontrolled for the purpose of grid services) can cause localized congestion on the grid (Ehsani et al., 2012).

This first result was adopted by Mal et al. (2012), where PEVs are coordinated upon entry to a parking garage with a radio-frequency identification (RFID) reader. In this scenario, the parking garage owner has enabled a physical aggregation of PEVs by requiring the use of a mobile application, which may be suitable to the growing parallel adoption of a Smart Grid. Upon entry to the parking garage, the PEV owner is required to create a desired charge profile which roughly correlates to departure time and necessary departure state of charge. In the interim, the aggregator/garage owner is at liberty to manage the charge in the batteries as necessary. This particular analysis optimizes the PEV charging by minimizing cost; the PEV preferentially charges when electricity prices are low, while the aggregator is able to defer a contract with the grid operator until revenue prices are high. This aggregation mechanism is also known as energy arbitrage (see Kamgarpour et al., 2013; Mathieu et al., 2013).

Along this line of research, Donadee and Ilić attempted to constrain the exogenous variables energy price, regulation price, and regulation signal energy with the expressed goal of minimizing future costs (2012b; 2012a). The challenge with this exercise comes from the real-world constraint that an aggregator must set the charge rate for each PEV before these three variables are known.

In an earlier study, Galus and Andersson addressed the optimization of power flow using reverse game theory, where the "energy hub agent" (aggregator) must forecast the load from additional units that enter the control area and preferentially weigh the dispatching commands for PEVs based on geographical load (2008; 2009). This analysis highlights the need to maximize the utility of each resource in every time interval (typically less than five minutes), while ensuring all PEVs are charged to user specifications.

Alongside this analysis, Guille and Gross addressed one of the more pressing issues to coordinated aggregation – uncertainty in forecasting individual PEV schedules (2009). The authors modeled the travel distances and travel times of individuals as truncated Gaussians to estimate the supply of PEVs that would be available as a function of time of day for a virtual aggregator. To facilitate fast communication with the virtual aggregator, a ZigBee transceiver is recommended due to its comparatively low purchase price and ease of availability.

In order to make VGI more compatible with the current wholesale frequency regulation market, Quinn et al. (2010) included a distributed, multiple aggregator scenario (see Figure 3.4) to show that aggregators can "improve the scale and reliability" of VGI services in the command and control architecture. Although the direct architecture (Figure 3.4, left), yields higher revenue to the PEV owner, the aggregative architecture "allows [PEVs] to make use of the current market."

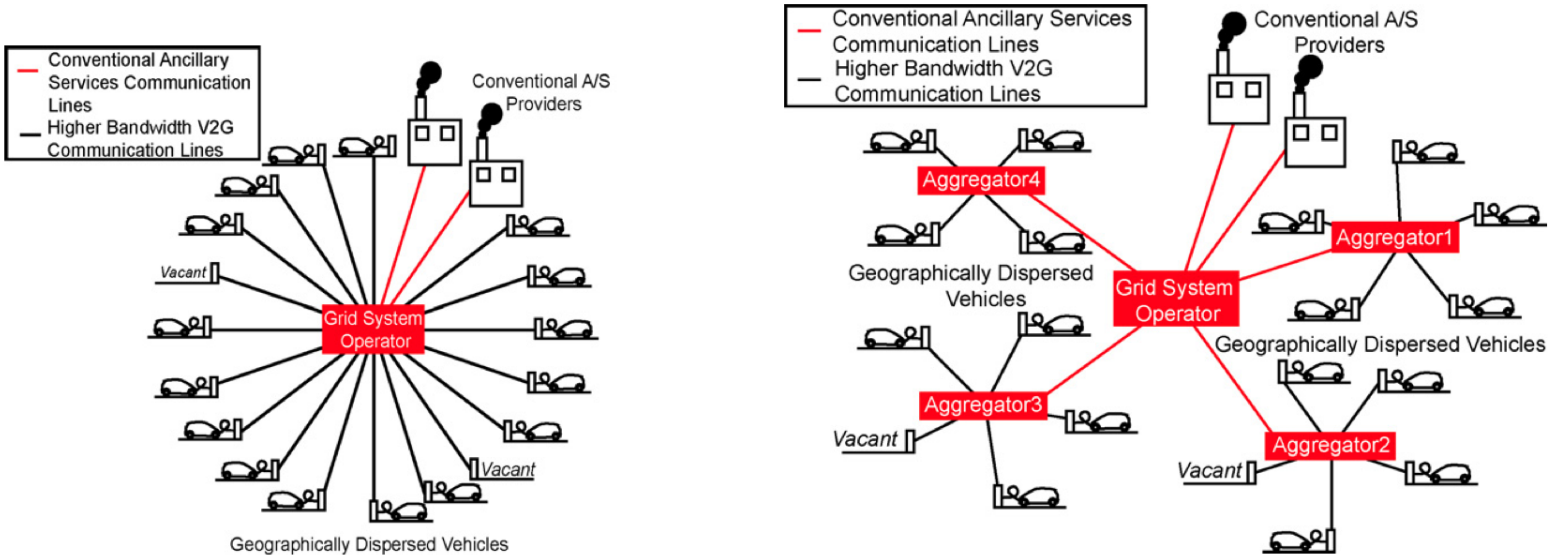

Figure 3.4: Two potential PEV organization plans for large-scale VGI: direct architecture (left) and aggregative architecture (right). As participation with VGI increases, reliable and efficient scaling architectures must be defined. Direct architecture (left) is the simplest approach, where each PEV individually contracts with the Grid System Operator (GSO) alongside Conventional A/S Providers. In an aggregative architecture (right), an intermediary PEV aggregator contracts on behalf of the group of PEVs with the GSO; from the perspective of the GSO, the aggregator functions the same as Conventional A/S Providers. From Quinn et al. (2010).

As anticipation of individual vehicle schedules is both difficult as well as crucial to moving towards a deterministic model, White and Zhang adopted the modeling techniques of Quinn et al. (2010), yet required that all PEVs spend half of their time providing regulation up and half providing regulation down (2011).

Going one step further, San Román et al. (2011) presented a full range of aggregation architectures, along with anticipated communications infrastructure, from individual domestic charging (CPUC step 1, Figure 3.3) to public access V2G on both public and private property (CPUC step 4) (2011). Challenges for each charge control optimization scenario are addressed, such as a discussion of how fast charging in public access V2G will hinder load management optimization.

The primary role of aggregation models like those described above is to highlight the need to mitigate uncertainty in forecasting resource availability. As can be anticipated, Guille formalized the notion that, given a sufficient pool of PEV resources in an aggregation control area (such as 5-10,000 PEVs), the cumulative resource may be forecast with remarkable certainty (2009).

3.2.2 Business Cases

Aside from the complexity of aggregating a resource whose predictability is minimal at low market entry levels, where one can either command that participation require a commitment of predetermined time periods and power or aim to statistically forecast these two unknown qualities of the PEV based on a number of exogenous assumptions, the fact remains that the business case for the aggregation of resources must hold water for all parties. For example, while aggregation of the PEV battery resource is optimal for the grid operator at the ISO

– in effect, the resource "behind the meter"[12] can be treated exactly as any other eligible resource – direct communication between the PEV owner and the grid operator would, in principle, be more profitable to the PEV owner without the need for aggregator fees (Quinn et al., 2010). An aggregator limits the immediate profitability to the PEV owner, while guaranteeing a reliability standard to the grid operator. That said, since there are no legal ways in which a single PEV owner can bid directly into the wholesale market, it is generally accepted that the "aggregative architecture is [the only] mutually acceptable [path] to all stakeholders" (Quinn et al., 2010).

This example is meant to underline the importance of a business case in order for V2G and V1G to gain traction. The resource, which is as-yet explicitly undefined by the CPUC (see Section 3.1), is shared among several stakeholders, and an equitable sharing of both revenues and responsibilities is necessary.

The responsibilities for V2G and V1G include any additional costs that are incurred as a result of participation in the market. This can range from potential battery wear[13] to specialized bidirectional charging and communications infrastructure to market entry fees. Although the value of the V2G/V1G service can exceed the cost of battery wear, equitable "implementation will require resolution of who is responsible" for these costs (Brooks, 2002). In an early cost-benefit analysis, the research team led by Kempton proposed rectifying this issue by placing sole responsibility for the battery costs on the aggregator; in this arrangement, the primary method by which the aggregator is compensated for its intermediary service is by providing free battery replacement in addition to free or minimal

[12]As discussed in Sections 4.2.3 and 4.3, the ISO requires that the signal granularity for available power capacity be at the level of each sub-LAP, which sends information to and from the ISO through a secure meter. Multiple power sources may be aggregated within a sub-LAP and transmit their joined signals through a single ISO meter. These power sources within a sub-LAP are said to be "behind the [ISO] meter."

[13]This is expected to be minimal in cases where the battery is only used to provide frequency regulation services. See Section 4.2.1 for further discussion.

charging costs (Kempton et al., 2001). Brooks advocates that the aggregator warrantee the battery (2002). In exchange for the ability to force participants to connect with the grid operator at predetermined times, Guille and Gross describe a "packaged deal" business model where the aggregator subsidizes the battery costs, including warrantees, maintenance, and reduced charging costs (2009).

The cost sharing responsibility for V2G/V1G specific infrastructure has only been touched upon lightly, and as a result, is the core focus of this thesis. Williams and Kurani suggest that the aggregator of the PEVs be the sole entity responsible for these additional costs, by way of creating an unintentional single-purpose fleet (2007). The authors suggest using idle airport rental cars; in this virtual fleet, the aggregator is the rental company, the PEV drivers incur none of the start-up costs for V2G/V1G specific infrastructure,[14] and the schedule of each vehicle is known with reasonable accuracy. Extensions of this business model may manifest in the near future, as airport-based peer-to-peer PEV car sharing programs are gaining popularity; FlightCar compensates travelers with free long-term parking for renting out their personal vehicle, and BMW's DriveNow allows renters to do one-way travel with the PEVs between several of their hub locations (Warren, 2013; Motavalli, 2013). The issue of responsibility for additional infrastructure costs, including necessary remuneration to offset these costs, is addressed in Chapter 5.

The most comprehensive aggregation business models were introduced by Kempton in a series of papers (Kempton & Tomić, 2005b; Kempton et al., 2001). There are three tiers to their vision, which are tailored to fleet applications (called "unified, many actors" in steps 2 and 4, Figure 3.3): (1) the aggregator (fleet owner/operator) retains control over the usage times of the PEVs and contracts directly with the wholesale electricity market; (2) the local retail utility is charged with aggregating the power from multiple fleets and incentivizes

[14]Marginal costs may be included over time if the PEVs do not generate sufficient revenue.

connection to the grid through tailored PEV electricity rate structures; (3) the aggregator is a third party networking agent that specializes in electricity markets, and may be a battery manufacturer, charging station company, cell phone network, or a combination of these entities. The core theme to these aggregation business models is that the aggregators will benefit from encouraging the PEV owners to adhere to a schedule of grid connection. This objective is challenging alone, since the Hour-Ahead and real-time needs of the frequency regulation market often differ from the Day-Ahead forecasts. Regardless of individual PEV compliance to the aggregator's direction for connecting to the grid, the entity that contracts with the ISO will incur a penalty[15] for not meeting contract obligations, such as a minimum of 500 kW.

At this point in the integration of PEVs with the grid, fleet vehicles are seen as the most practical application for V2G/V1G. Most fall within the CPUC's step 2 (Figure 3.3), where many individual PEVs who are unified under the control of a fleet operator participate in controlled charging (V1G), but none thus far have actively bid into the wholesale frequency regulation market. The following chapter discusses the practical limitations of bringing this step of VGI to reality.

[15]The penalty is both monetary and participatory – persistent noncompliance with standards will revoke the ability to participate in the market.

4 HOW WILL VEHICLE-GRID INTEGRATION WORK IN PRACTICE?

The previous chapter discussed the potential for V2G/V1G in vehicle-grid integration; this chapter discusses how this is beginning to be implemented in practice. Even as state regulators are solidifying a four-step plan for integrating PEVs with the power grid (Figure 3.3), research groups and private organizations have been testing different aspects of controlled charging and discharging for over a decade. These pilot projects serve the crucial role of determining the limits of possibility for this new resource, especially in terms of how the requirements of various stakeholders will be met. This chapter discusses a handful of pilot projects that have successfully demonstrated the ability of PEVs to push power to the grid. It then discusses stakeholder issues, including the requirements for participation in the wholesale market. The final sections discuss the most recent V2G pilot project, which is laying the regulatory and technological framework for participation in the market.

4.1 PEV Pilot Projects: Success With Pushing Power To The Grid

The majority of the V2G/V1G pilot projects over the last decade and a half have been feasibility demonstration projects, where the purpose was to prove that a PEV can successfully respond to an AGC signal (see Section 2.2) in a simulated frequency regulation contract, and more importantly that the power flowing between the grid connection and the PEV can be controlled by a third party, both as controlled charging and controlled discharging. The distinction that all of these projects have from the one described at the end of this chapter is that, although they have demonstrated success in interacting with a simulated grid operator, they have not formally contracted with the frequency regulation market.

Among the first of these projects, Brooks and Gage teamed with AC Propulsion in

2002 to demonstrate to the California Air Resources Board the ease with which PEVs can provide ancillary services to a grid operator in California. Following the concept as outlined in Kempton et al. (2001), they tested the ability of a 20 kW BEV to respond to a fraction of a historical AGC signal from the CAISO over a one-week period. During testing, the BEV was not used for personal transportation; the only application was that of the feasibility demonstration. The group was able to show that the "wireless data transmission times were within ISO system requirements" of sub-4 seconds, and that the "daily energy throughput through the battery pack while performing regulation" was similar to that of normal driving.

Several years after this project, Brooks (now with Tesla Motors) conducted a study with a Pacific Gas and Electric (PG&E) representative to demonstrate V1G ancillary services with a 16.8 kW rated Tesla vehicle (Brooks & Thesen, 2007). This project only demonstrated regulation down services, primary because the auto manufacturer (Tesla) wished to remain prudent with excessive strains to the battery pack. BMW conducted a similar study in 2011 with a fleet of stationary 6.6 kW rated BEV Mini-Coopers (Dempster, 2012). The power in these BEVs' battery packs was controlled for regulation down by a fleet manager software program that coordinated each vehicle's charging rate with the need to meet a regulation down AGC signal. Although these vehicles were not operated for transportation during the study, coordinated charging by the fleet aggregator was necessary in order to avoid prematurely saturating battery packs, thereby reducing the aggregative capacity to respond to the power signal. Because of this, vehicles that contract for regulation down only are limited to providing, on average, half of their rated power capacity: 8.4 kW for the Tesla and 3.3 kW for the Mini-Coopers. As we will see in Chapter 5, this can complicate the economics for a fleet manager considering V1G or V2G; participation in V1G[16] will require an artificially large fleet to meet the minimum market entry requirements.

[16]See CPUC step 2, Figure 3.3.

The research group led by Kempton at the University of Delaware has been the most comprehensive in terms of demonstrating the feasibility of V1G/V2G. In 2010, this group developed what they coined a Grid Integrated Vehicle (GIV) that was capable of responding to a bidirectional power request signal and permitted it for public use, both on the roads and in the regional power market (Kempton, 2010). They converted a Scion xb into an "eBox"[17] with an on-board bi-directional charger manufactured specifically for this project by AutoPort and developed a proprietary SAEJ1772-compliant bi-directional EVSE prototype. Their proprietary aggregation software manages the power of each eBox to balance the needs of the driver for its next trip, and the power for regulation that can be bid into the local PJM ISO/TSO market. As with all previous demonstration projects, this group successfully proved that PEVs provide a response to the power signal that is aligned with the command signal to a degree much higher than any mechanically rotating equivalent. This project was also the first to secure legislation that enables PEVs to both act as a load-serving entity[18] with the local utility and provide net metering services with V2G. Although these laws apply only to the local utility (City of Newark) and ISO/TSO (PJM Interconnection), they are instrumental in blazing a trail for PEVs to be monetarily compensated as a distributed power resource.

4.2 Stakeholder Issues And Requirements To Participate In The Wholesale Market

As VGI demonstration projects, such as those discussed in the previous section, inch further from the testing room and closer to reality, the numerous stakeholders involved in the process are being identified through their concerns and requirements for participation in

[17]This work was conducted in a consortium of organizations; AC propulsion was involved in designing the V2G-ready on-board charging system.

[18]The requirements of this type of load-serving entity are that the generation facility be 25 kW or less, and that it "meet IEEE 1547 standards" (Senate Bill 153, 2009).

the wholesale market. In certain situations, the depth of involvement of a stakeholder may depend on how the "resource" from VGI is defined, as discussed in Section 3.1. This section outlines the stakeholders involved from a perspective of functional participation in the wholesale market. At minimum, these parties are the customer, the utility, and the ISO.

4.2.1 Customer

Although this thesis assumes the role of the customer is filled by the owner(s) of the PEV(s), both the CPUC and the CAISO are working to clarify who will legally take the role of the customer/resource when "vehicle-based grid services" become a reality (Langton & Crisostomo, 2013; CAISO, 2013). Since the CAISO regulations for a Non-Generating Resource do not explicitly define the resource, the CPUC in particular has formalized a handful of options: the vehicle (PEV), the charging station (EVSE, electric vehicle supply equipment), a facility (such as a building or workplace[19]), or an aggregation of resources (provided that the aggregation is within a single CAISO Sub-Load Aggregation Point, sub-LAP) (California ISO, 2012).

Defining the resource directly impacts the legal responsibilities for maintaining CAISO-utility interconnection requirements. For this reason, although the CAISO will permit the resource to be defined at the sub-LAP, it would prefer to measure the performance of the resource next to the source, which favors the vehicle as the resource (Langton & Crisostomo, 2013). Even if the vehicle is legally defined as the resource, there are a handful of barriers specific to several stakeholders that must be overcome. For brevity, the most pressing of these issues are discussed below: battery degradation, and range anxiety/availability.

The Original Equipment Manufacturer (OEM, or automaker, such as Nissan or Toyota) will be concerned that the vehicle consumer is not adversely affected by VGI participation

[19]See, for example, the discussion of a parking garage as aggregator in Section 3.2.1

(Bedir et al., 2014). To that end, discharging the vehicle's battery (active V2G participation) voids the battery warrantee (Dempster, 2012). One of the primary barriers to PEV adoption is driven by the high cost of batteries, as the battery can account for as much as 50% of the vehicle's price (Tsang et al., 2012). OEMs, then, are understandably reticent to warrantee a battery that may undergo increased cycling; the OEM does not want to be responsible for replacing a prematurely depleted battery pack. For the time being, this is the primary reason why V1G can be realized before V2G; with one-directional, controlled charging, V1G does not void the OEM's battery warrantee.

There is considerable evidence to suggest that concern over batter degradation from frequency regulation grid services is unnecessary, and will not decrease the lifetime of the battery (Wellinghoff, 2008). Kempton and Tomic (2005a) point out that shallow battery cycling, typically less than 3% depth of discharge (DoD), impacts the battery lifetime less than deep cycling, the benefits of which depend on the battery chemistry. For example, a Saft lithium-ion battery, cycled at 3% DoD, lasts 10 times longer than one cycled at 100% DoD, and lead-acid and NiMH batteries last 28 times longer than when cycled at 80% DoD (Miller & Brost, 2001; Raman et al., 2003). In terms of measurable impact on the battery's lifetime, an earlier V2G demonstration project by Brooks found that "the power levels associated with regulation are typically an order of magnitude lower than those associated with driving the car" (2002).

A recent paper by Han and Han (2013) confirmed these findings and measured the degradation as a function of DoD (see Fig 4.1). Their results suggest that concerns about battery degradation associated with frequent cycling are misplaced. In particular, although high charge rates are typically assumed to accelerate degradation, the depth of discharge is a stronger determinant of battery cycle life. The authors find that charge rates below 1 C (most 16 kWh batteries charge at 0.1 to 0.2 C) do not result in significant degradation.

Since all cycling events impact the lifetime of the battery, Han and Han (2013) defined non-trivial battery degradation from V2G participation as that whose cost exceeds the revenue from market participation. They found that anticipated V2G profits comfortably offset any costs associated with battery degradation.

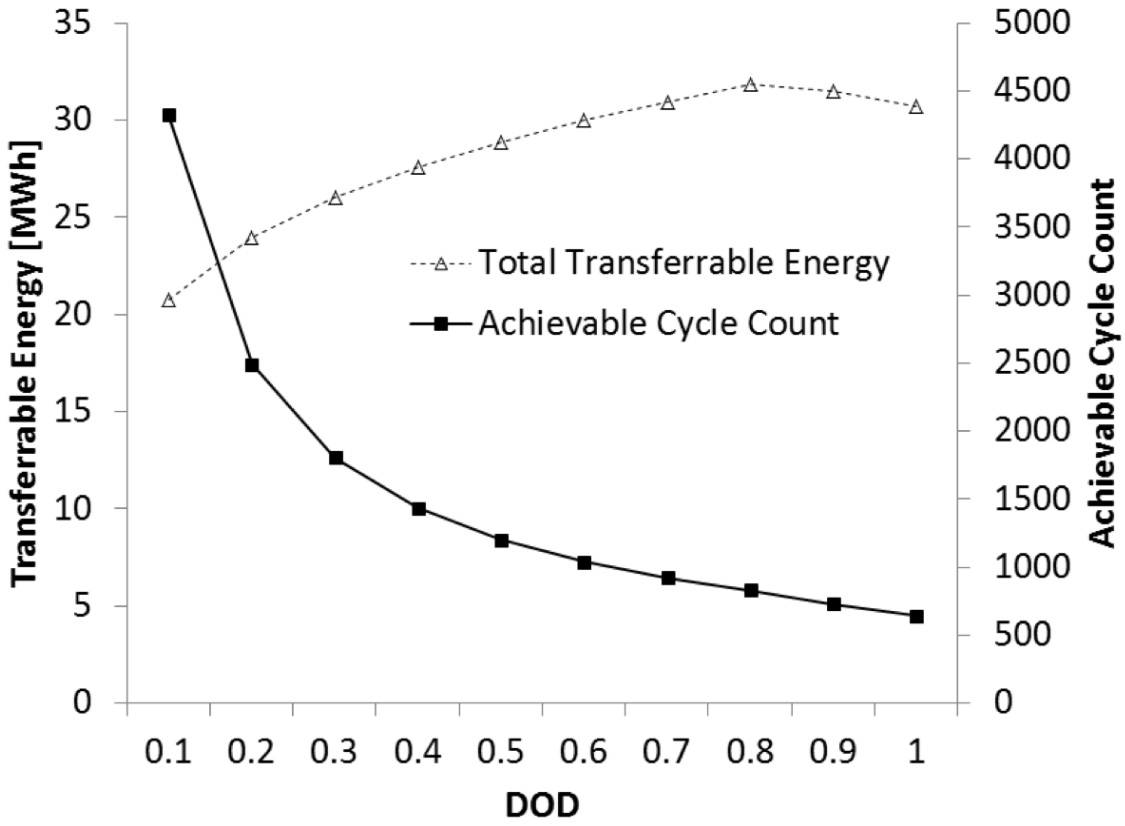

Figure 4.1: Battery degradation, measured in transferrable energy and achievable cycle count, as a function of depth of discharge. Depth of discharge directly affects the total achievable cycle counts for a vehicle battery (solid line), which is inversely proportional to the total transferrable energy in each discharge (dotted line). These results suggest that depth of discharge, as opposed to discharge cycle frequency, has the potential to reduce the lifetime of a PEV battery. From Han & Han (2013).

Finally, the most basic concern of the customer – as the PEV owner and operator of the "resource" – is the availability of the vehicle for its primary purpose, personal trans-

portation. To allay these concerns, most studies rank the user's transportation needs as the highest preference, sometimes by requesting the user designate a desired SOC at a specific time (Mal et al., 2012). To solidify the importance of this preference, the CPUC recently suggested methods for power demand forecasters to anticipate the load profiles of PEVs, with the understanding that their primary use is for personal transportation. Understanding the load profiles of PEVs will help elucidate their ability to also serve as storage resources (Langton & Crisostomo, 2013).

Beyond loss-aversion concerns, where the fear of the customer is that participation in V1G/V2G may degrade the functionality of the PEV for its primary use, customers also have a vested interest in potential revenue mechanisms. However, customers may not have much say in how the service is compensated because there are currently no regulations that allow them to directly access the wholesale market. As discussed at length in Chapter 3, an aggregator will be necessary to manage the power and revenue transactions between the individual customer and the ISO, and they will anticipate compensation for this service. As will be discussed in Chapter 5, the compensation to the aggregator should be at least equal to the PEV's avoided cost of installing the necessary VGI communications infrastructure.

To facilitate the accounting of potential revenue streams, the CAISO has initiated discussions on regulating sub-metering (California ISO, 2013). The details have yet to be finalized, but the goal is to meter grid services separately from direct electricity consumption (initially proposed by Brooks (2002)). Since utilities typically retain the final decision over sub-metering and communications infrastructure in their service area, they are well-positioned to serve as aggregators. To support this claim, the first regulation that allows a utility to sell power on the wholesale market on behalf of a customer was recently passed for Southern California Edison. This regulation, called Rule 24, was initiated by the Department of Defense V2G pilot projects in Southern California, and specifically requests

that the utility be the aggregator of the resource (see Section 4.3 for more details).

4.2.2 Utility

The customer's utility will invariably play a major role in facilitating VGI, whether or not it formally aggregates the resource for the ISO on behalf of the customer. A retail utility traditionally purchases power from the ISO on the wholesale market and sells it on the retail market to the customer. This makes the utility a natural choice for aggregator, even if it is not the only choice for an aggregator.

Regardless of the utility's potential role as resource aggregator, the additional power throughput introduced by VGI will have impacts on utilities. Most significantly, the distribution and wholesale price signals may conflict (Langton, 2013a). If customers have a direct link with the wholesale market yet purchase electricity on the retail market from the utility, there may be a conflict of interest when the price signals from each tier trend in opposing directions; the utility may not wish to deliver power at a retail price point (pre-purchased on the wholesale market) for which they would lose revenue. This is an area of regulation that the CPUC is in the process of untangling, as there is currently an unclear prioritization of utility and wholesale market needs.[20]

Beyond retail/wholesale market incongruencies, the equitable sharing of distribution system responsibilities and benefits is unclear. PEVs have the potential to congest distribution wires from increased power throughput in advance of system upgrades, without bearing the responsibility of paying to use the wires. On the other hand, this provides an opportunity for utilities to value usage of distribution wires as a separate service. It is possible for PEVs to overload neighborhood transformers when responding to price signals from

[20] In its most recent V2G white paper, the CPUC references that there is an "upcoming PEV sub metering proceeding" (Langton & Crisostomo, 2013).

the wholesale market, especially if the price signal is sufficiently lucrative. If utilities are able to monitor and control PEV loads alongside these price signals, the life expectancy of these transformers may be lengthened six times due to lightened power throughput (Bedir et al., 2014; Yilmaz & Krein, 2013).

Utilities share similar motivations for participating in VGI as with demand side management (DSM), largely because it will help alleviate the need to invest in generation capacity upgrades. These motivations, however, are not always similar between organizations. In particular, although distribution wires may experience increased usage, the reliability of distribution will likely increase with VGI. San Diego Gas and Electric is currently weighing this benefit alongside the cost of potentially overloaded transformers and wiring. Southern California Edison, on the other hand, is most interested in ensuring that renewably generated power is used efficiently. Their view is that PEVs through VGI may help alleviate the demand for power from fossil fuels. Pacific Gas and Electric sees involvement in VGI as a step in the path towards the smart grid (Bedir et al., 2014). Most investor owned utilities (IOUs) prefer implementation of automated demand response (open ADR) communications, which was initiated by the LBNL, to manage the communications infrastructure for VGI in lieu of direction controlling loads (Bedir et al., 2014; Kiliccote et al., 2010, 2013). The natural solution to many of these IOU concerns may be for the utilities to act as the aggregator in order to reconcile power congestion and pricing signals; most IOUs prefer to nudge loads with their retail price signals in lieu of direct control (Bedir et al., 2014). Across the board, utilities prefer to influence loads through retail price signals, reminiscent of DSM strategies.

4.2.3 Independent System Operator

The ISO is arguably the most influential stakeholder in VGI; it dictates the rules by which customers may participate, if at all, in the wholesale market. ISOs and RTOs understand, however, that small resources will be invaluable tools in building a more resilient power grid. As a result, ISOs/RTOs have initiated protocols for allowing Non-Generating Resources (NGR) to participate in the wholesale market by drafting revisions to their metering and telemetry requirements (California ISO, 2012). Although PEVs fall under the classification of NGRs, to date only programs that depend on demand-side management, such as demand response, actively use the NGR guidelines (Kiliccote et al., 2010). For participation with VGI, ISOs are motivated by customer compliance with existing protocols, including minimum resource size (even for NGRs), and metering and telemetry requirements.

Wholesale market resource size requirements differ depending on the ISO. For example, the PJM, which has been working closely with the V2G research group at the University of Delaware, including agreeing to net metering legislation (see Chapter 3), is the entity that aggregates resources. This is a key distinction from ISOs under Western Electricity Coordinating Council (WECC) jurisdiction, which does not permit the ISO to aggregate the resource. Participation in the wholesale market is easier for the customer, whereas managing the aggregation requires more effort from the ISO (MacDonald et al., 2012). Requirements for participation in the CAISO wholesale frequency regulation market are more stringent. The resource must be able to provide at least 500 kW at any time, with a minimum power interval of 10 kW. As most PEV on-board chargers are rated at 3.3 to 6.6 kW in AC, most PEVs that wish to participate will need to provide power in DC mode. If the pre-aggregated resource fails to meet the AGC signal requirements during a verifica-

tion period, the resource is no longer permitted to participate (Federal Energy Regulatory Commission, 2011).

The recently developed expanded options for metering and telemetry with the CAISO are intended to facilitate the market participation of distributed energy resources, such as demand response and NGRs like V1G/V2G. Metering refers to tracking data on actual dispatched units for revenue and billing, and telemetry is required for real-time performance monitoring. The planned expansions will allow the ISO to monitor performance and revenue of small and distributed resources that often need to aggregate their power capabilities in order to meet minimum capacity requirements, while adhering to the ISO's strict communications security requirements (see Figure 4.2 for a schematic of the metering and telemetry organization).

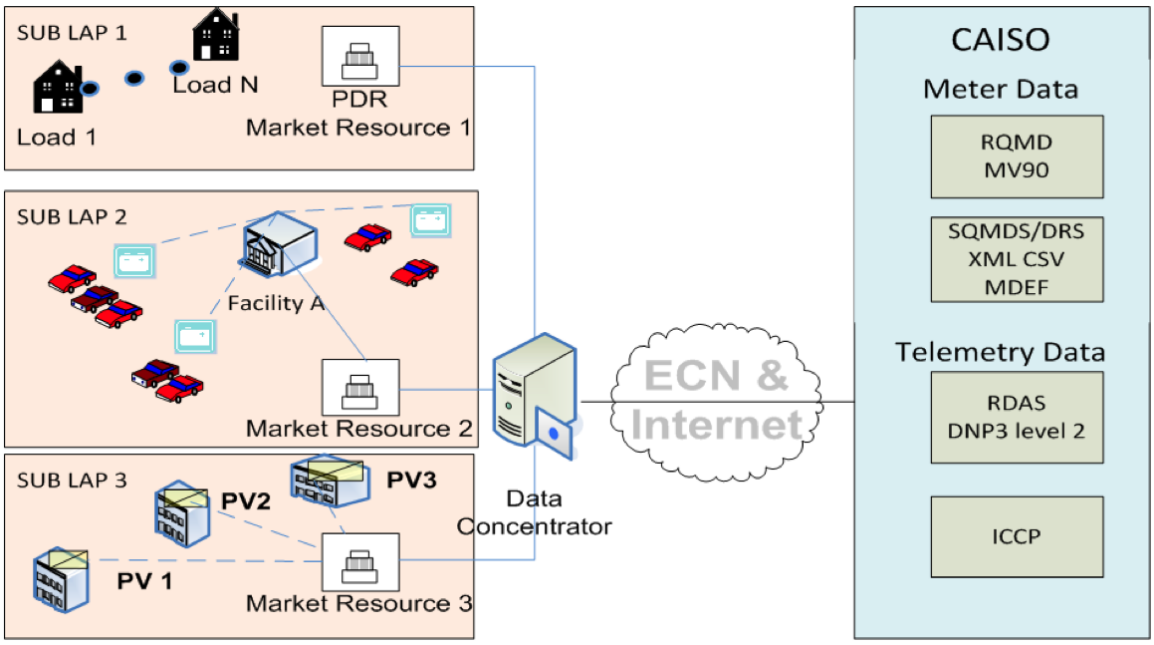

Figure 4.2: Proposed telemetry and metering organization options for VGI from the CAISO. The CAISO telemetry and metering options are being expanded to allow the inclusion of small distributed power sources like PEVs (middle panel, left) such that, below the Sub-LAP level, each market resource functions identically. The power from each market resource (left) is aggregated through a Data Concentrator, and metering and telemetry data from each resource is sent to the CAISO (right) through a secure and direct internet connection called the Energy Communication Network. Eligible market resources for this type of metering and telemetry include Proxy Demand Response (top panel, left), controllable loads from PEVs (middle panel, left), and Photo-Voltaic power sources (bottom panel, left). From California ISO (2013).

Although the CAISO does not intend to aggregate distributed and small resources, like PJM does, it is motivated to facilitate the inclusion of these more dynamic resources into their portfolio of power management capabilities; this is being done through adapting the metering and telemetry options. Smaller resources (like PEVs) that wish to participate in the wholesale market do not typically have the economical scale to obtain a direct Energy Communication Network (ECN[21]) connection. In lieu of a direct ECN, the CAISO is

[21]The ECN is the secure communication line that the CAISO requires for metering and telemetry.

proposing to allow small resources to obtain telecommunications access to the ECN with the internet as part of the first phase of adjustments. In the second phase, the ISO is proposing the use of Data Concentrators to both aggregate the resource for the ISO and control signal disaggregation. The data concentrator would be the entity that interacts with the ISO on behalf of individual resources and would have the capability to aggregate resources from multiple sub-LAPs, as shown in Figure 4.2. All resources below the sub-LAP level will need to be aggregated where the CAISO metering device is located (California ISO, 2013).

4.3 PEV Pilot Project: Pushing Power To The Grid, And Participation In The CAISO Market

Although the concerns and requirements from a growing list of stakeholders in VGI are lengthy and often incompatible, one recent V2G pilot project within the CAISO service territory is paving the way for PEVs to participate in the wholesale market with VGI-enabling legislation. The Department of Defense (DoD) has initiated two V2G pilot projects in the Southern California Edison utility's service area, one of which has all but begun to actively bid into the wholesale regulation market. This is a unique situation, as the DoD is under special mandate to reduce gasoline consumption by 2% annually, increase alternative fuel consumption (such as electricity) by 10% annually, and integrate PEVs into its fleets where economically reasonable.[22] Compounding this shift to PEVs, the DoD has a special interest in ensuring each base has the capability to island itself from the greater power grid for security reasons; the recent push by the DoD to integrate PEVs with the national power grid to ameliorate load fluctuations comes alongside increased research into the potential

[22]Executive Order 13423 (January 24, 2007), Executive Order 13514 (October 5, 2009), and 10 USC Section 2922, subdivision (g).

for PEVs to help manage microgrids such as these (Marnay et al., 2013; Stadler et al., 2012; Marnay & Lai, 2012).

The most significant piece of recent legislation that makes it possible for the DoD to sell its PEV resource to the CAISO on the wholesale market is the CPUC Resolution E-4595, finalized in July 2013 (California PUC & Southern California Edison, 2013). The resolution is a special arrangement between Southern California Edison (SCE) and the DoD at its Los Angeles Air Force Base (LA AFB) and Naval Air Weapons Station at China Lake, with the LA AFB site launching first. In it, SCE manages the DoD PEV resources as its Scheduling Coordinator under the CAISO's NGR model and bids this resource into the ISO's wholesale regulation market on behalf of the DoD. One of the goals of the resolution is for SCE to gain experience with managing direct participation for its customers, specifically those that are classified as NGRs. Similar projects, such as demand response, have no need for an intermediary like the utility, as they were recently granted the ability to enter into direct contracts with the ISO (Kiliccote et al., 2010). The resolution is informally referenced as Electric Rule 24, a CPUC regulation that will expand this new utility-customer relationship to include other IOUs.

The unique advantage to the DoD V2G pilot projects, especially at the LA AFB, is that many of the theoretical constraints of V2G, such as communications hardware, must be sorted out within the project's timeline. Although the solutions the project finds may not prove to work for all VGI applications that wish to participate in the wholesale market, they certainly set precedent for at least one path that can work.

The project-specific infrastructure that is required is used as a guide for the economic analysis in Chapter 5, as it is the only existing example of V2G with wholesale market participation. The infrastructure needed includes a CAISO revenue-grade meter that will disaggregate the PEV power draws from all other loads at the LA AFB, a Bosch "eMobil-

ity" fleet management system, the LBNL Distributed Energy Resources Consumer Adoption Model (DER-CAM) that optimizes and schedules the bids into the market, the Akuacom Demand Response Automation Server (DRAS) that transmits scheduling requirements from DER-CAM to the Scheduling Coordinator (SCE) and from CAISO to eMobility using the LBNL-developed Open Automated Demand Response (OpenADR) communications protocol, and a proprietary bi-directional EVSE manufactured by Princeton Power Systems, which is based on their 15 kW grid-tied inverter model GTIB-15 (Loc & Princeton Power Systems, 2014; California PUC & Southern California Edison, 2013; Marnay et al., 2013). A schematic of the communications architecture for the LA AFB V2G pilot project is shown in Figure 4.3.

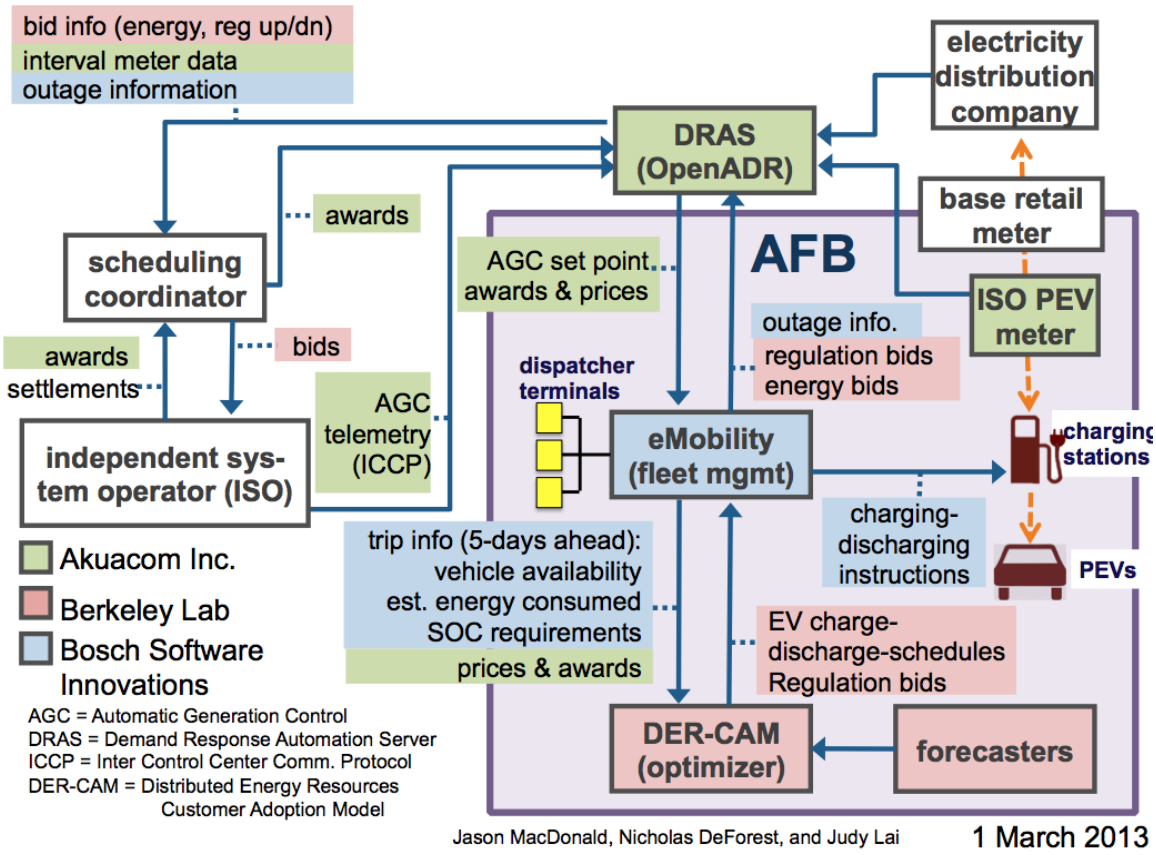

Figure 4.3: Los Angeles Air Force Base V2G pilot project communications schematic, organized by whether the equipment is onsite, and what type of information is being communicated. Red components (managed by the LBNL) relay bid information, such as energy for each regulation market. Green components (managed by Akuacom Inc.) relay interval meter data, and blue components (managed by Bosch Software Innovations) relay power outage information. Onsite, the communications architecture for the Los Angeles Air Force Base V2G pilot project includes fleet management software (eMobility), a PEV charge and discharge scheduling optimizer (DER-CAM), and an ISO PEV that will communicate between the retail utility meter and the Demand Response Automation Server, both offsite. The DRAS communicates with the ISO's offsite Scheduling Coordinator to manage bids, awards, and settlements. As much of this software is currently proprietary, this thesis includes the ISO PEV meter and the V2G charging station in the holistic cost of operating a V2G fleet, as well as CAISO market participation fees. From Marnay et al. (2013).

Beyond V2G-specific infrastructure, market participation also requires monthly fees from both the Scheduling Coordinator and the ISO for several layers of communications

access to the market (discussed in Chapter 5). These fees have been absorbed by large power producers in the past with ease due to economies of scale. Pilot projects like that of the DoD at the LA AFB can help to illuminate the potential economic vulnerabilities for small and distributed resources that wish to compete with existing large-scale power producers.

4.4 Historical ISO/RTO Frequency Regulation Prices

The historical prices awarded for ancillary service bids can indicate a reasonable estimate for revenue from this market. Each balancing authority in the US has different historical trends that are largely caused by differing regulations and local specializations in power production (see Figure 4.4 for a map of the Regional Transmission Organizations in the US). The remuneration price for holding a set capacity of power in reserve for an hour is called the hourly market clearing price (MCP), measured in $/MW-h. The MCP is affected by bid availability and opportunity cost of the most expensive resource awarded, where the final MCP is set by the highest priced bid that is awarded. The MCP, along with the size of the market (volume of procured capacity), determine the state of the ancillary service market. In particular, the size of the market indicates how robust it will be to a large penetration of new entrants; a large fraction of low bid price entrants may in turn lower the MCP (Woychik, 2008).

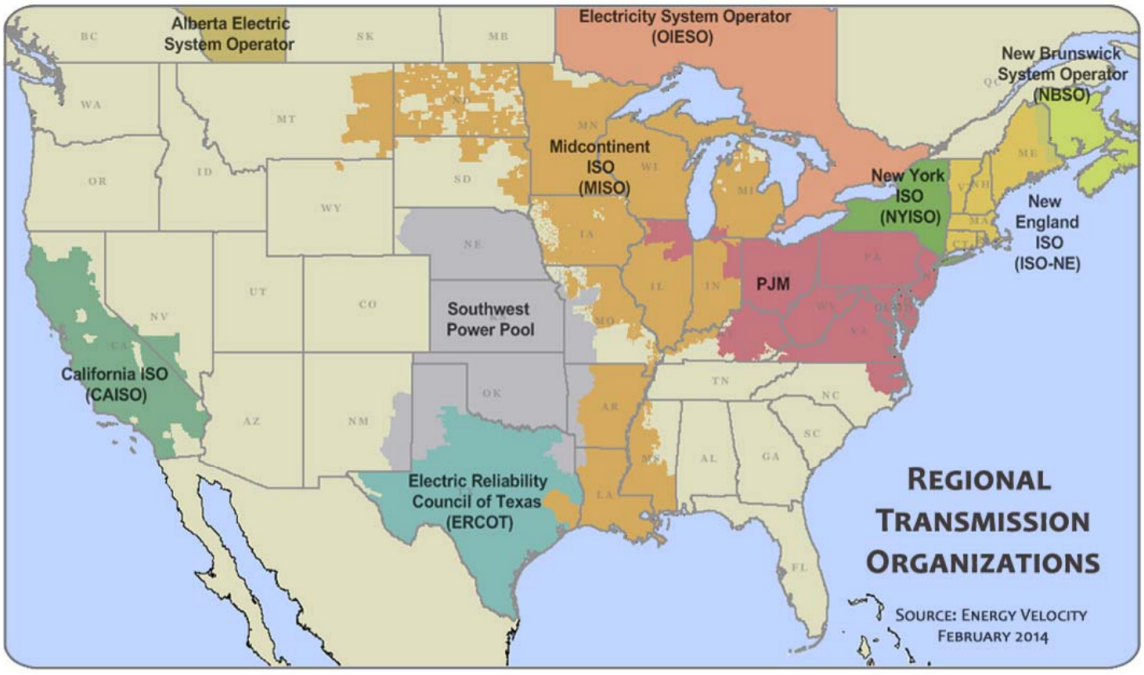

Figure 4.4: FERC-controlled Regional Transmission Organizations in the United States and southern Canada. The California ISO manages power for the majority of the state; some municipalities, such as Sacramento and Los Angeles, manage power independently. From FERC (2014).

Revenues from proposed V2G services have been based largely on the MCP from the year of the study, but this neglects to illustrate both seasonal and long-term variability in prices. Figure 4.5, for example, shows a marked downward trend in the MCP of frequency regulation in the east coast NYISO between early 2009 and late 2011 (MacDonald et al., 2012). This trend is similar to the average annual values in three other east coast RTOs – MISO, PJM, and ISO-NE. Although this exact trend is not replicated on the west coast with the CAISO (see Table 4.1), it illustrates the tendency for long-term MCP forecasting to be volatile.

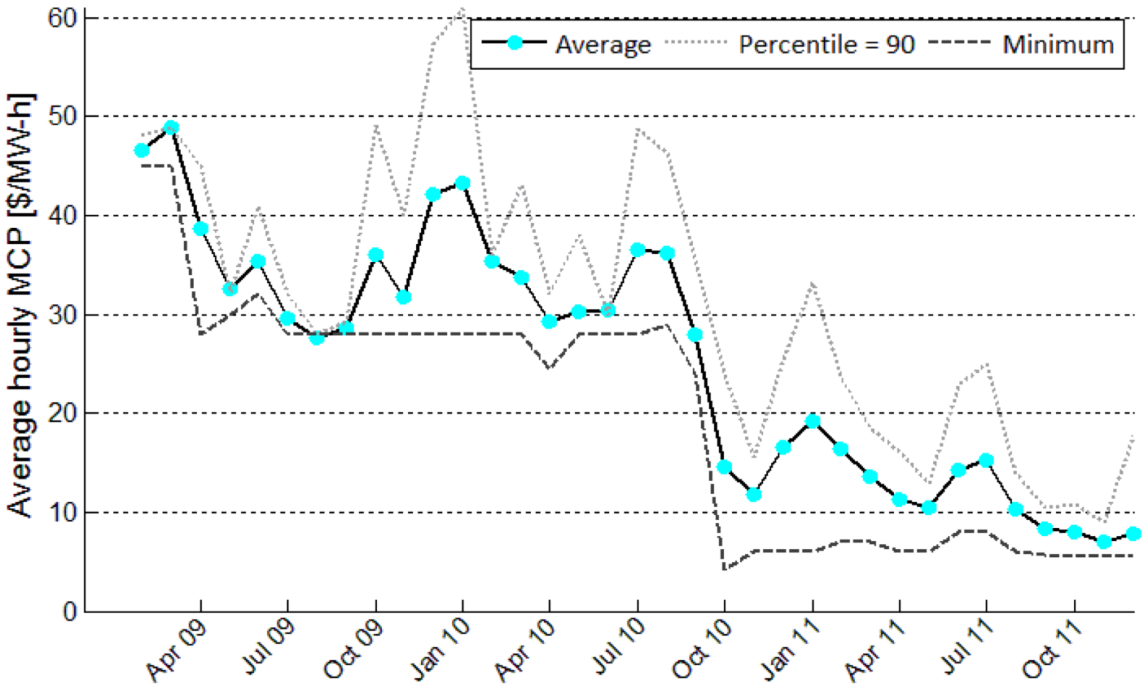

Figure 4.5: Historical frequency regulation market clearing price for the NYISO from February 2009 through December 2011. The market clearing price in the frequency regulation market, shown here for the NYISO, has been steadily decreasing over the last half-decade. This trend is prevalent for most ISO/RTOs in the US. From MacDonald et al. (2012).

Table 4.1: Frequency regulation MCP (combined or up/down) in United States ISO/RTOs, measured in $/MW-h. Italicized values indicate day-ahead market prices, while others are for real-time market prices. Blank indicates unavailable data for that year. Prices from 2002 through 2006 (averages) are from Kirby (2006), and those from 2009 through 2011 are calculated in MacDonald et al. (2012). Although frequency regulation is a comparatively lucrative market, the compensation for this resource has been decreasing steadily over the past decade.

ISO (Reserve Zone)	2002	2003	2004	2005	2006	2009	2010	2011
CAISO (South)	26.9	35.5	28.7	35.2	38.5		8.06/ 6.75	11.93/ 7.27
CAISO (North)	26.9	35.5	28.7	35.2	38.5		5.64/ 4.98	9.21/ 6.93
ERCOT		16.9	22.6	38.6	25.2	9.70/ 7.25	9.81/ 8.27	22.67/ 8.58
MISO						12.43	12.17	10.83
PJM						*23.51*	*17.95*	*16.42*
NYISO (East)	18.6	28.3	22.6	39.6	55.7	37.20	28.80	11.80
NYISO (West)	18.6	28.3	22.6	39.6	55.7	37.20	28.80	11.80
ISO-NE	9.26	7.07	7.16					

Resources that must respond quickly to a signal from the ISO, such as those providing frequency regulation, experience both seasonal and diurnal variability (Mathieu et al., 2012). This can have staggering impacts for predicting the MCP, especially on the day-ahead market. Figure 4.6 illustrates the hourly MCP for a full season of regulation up in the CAISO South region. In the both winter and summer months, the early morning hours are compensated less than the afternoon and evening hours. The summer months, however, can see extraordinarily high MCP for the late afternoon hours. Flexible loads, such as V1G and even V2G from PEVs can take advantage of the diurnal and seasonal variations to provide regulation when it is most valuable; most vehicles will be plugged in during the peak compensation hours.

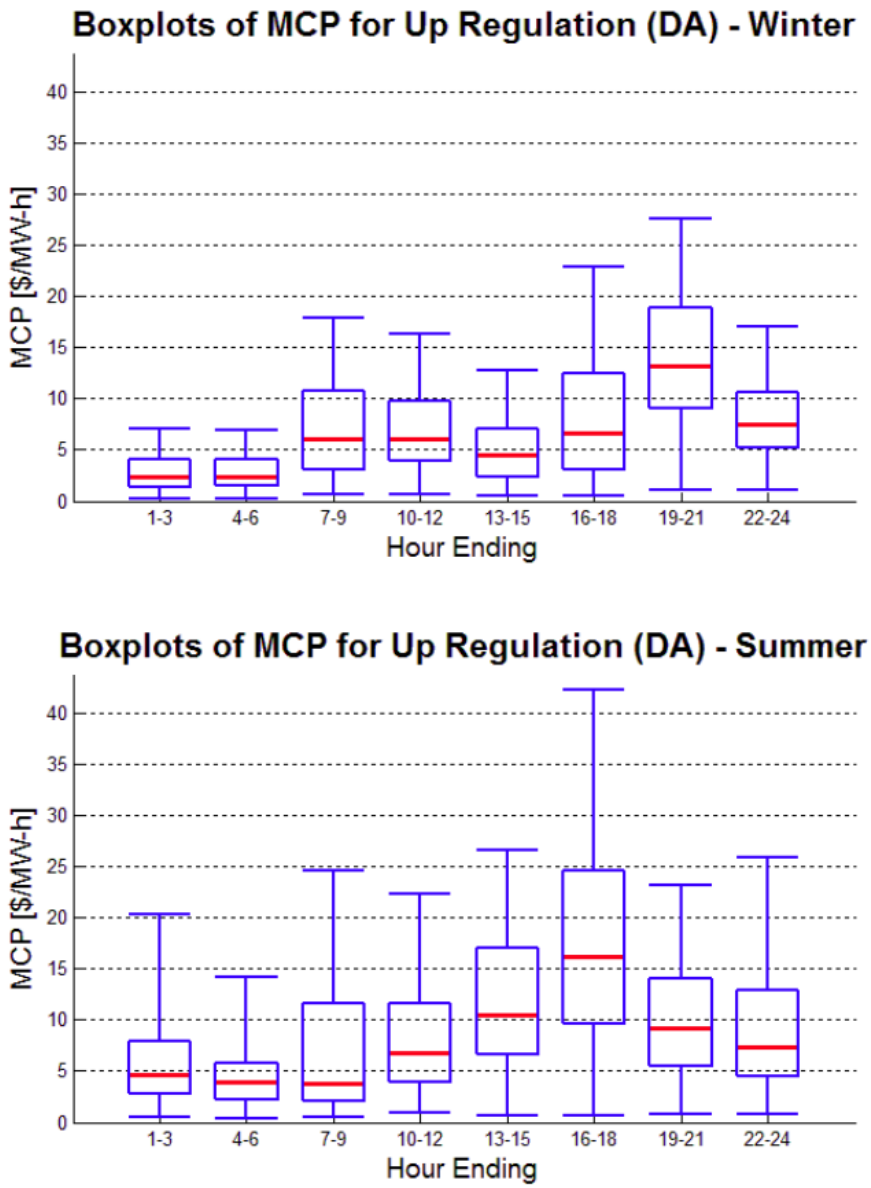

Figure 4.6: Seasonal and daily variability in the market clearing price for CAISO frequency regulation in 2011(South region). The MCP varies dramatically throughout the day, depending on the season. Boxplots for regulation up compensation in the Winter (top) and Summer (bottom) months show the average MCP for each three-hour interval (red line), the first and third quartiles, and the minimum and 90th percentiles. In the summer months, the higher MCP in the afternoon hours reflects the seasonal dependence on cooling units, whereas the MCP in the winter months is driven up by relatively higher demand for power in the early morning and late evening hours. From MacDonald et al. (2012).

This chapter was meant to illustrate the complexity that is involved with bringing distributed PEVs as a resource to the CAISO wholesale market. Although several research and development groups have proven that PEVs can respond to an ISO's frequency regulation signal within desired parameters (Section 4.1), the abundance of stakeholders that have concerns and opinions on the implementation of V1G and V2G presents an array of options, some mutually conflicting (Section 4.2). The most recent V2G pilot project, with the DoD's LA AFB, is the first to initiate a partnership with the local utility, SCE, as both an intermediary and a resource aggregator. This project paves the way for V1G/V2G market participation, but also highlights the economic vulnerabilities that come with investing in a new type of infrastructure, especially for small and distributed resources. The following chapter discusses these additional costs, and frames the marginal investments necessary for both V1G and V2G alongside existing CAISO frequency regulation revenue rates to demonstrate economic viability in the near-term.

5 WILL PEVS BE ABLE TO COMPETE IN THE CAISO WHOLESALE MARKET?

The introduction of legislation like Rule 24, which will expand Resolution E-4595 to allow all California investor owned utilities (IOUs) to schedule bids into the CAISO wholesale market on behalf of retail customers, will pave the way for PEVs to participate in the wholesale market even though this Rule limits the aggregating intermediary to an IOU. This initial path will prove useful in highlighting the operational challenges as yet unforeseen with market-enhanced VGI.

The push to include PEVs in the portfolio of distributed resources has, to this point, been focused on mechanisms to allow PEVs to participate in the ISO wholesale market. Most of these studies are economically driven; attention is only spent on the argument that the average revenue rate for frequency regulation, the comparatively lucrative market, will be sufficient to cover the cost of the PEV[23] in a handful of years, and generate surplus revenue for the owner afterwards (see, e.g., Kempton & Tomić, 2005a; Marnay et al., 2013). This comes largely on the heels of anticipated reluctancy to purchase PEVs compared with conventional vehicles because the high cost of the batteries are seen as an impediment to reducing the vehicle's purchase price (Tsang et al., 2012, 12).

No existing studies incorporate the costs of V2G-enabling infrastructure – nor the costs of conventional charging infrastructure – and market participation fees into their analyses when determining whether the CAISO's regulation remuneration rate will generate a revenue. Even the most recent project at the DoD LA AFB, when discussing the economic viability of the project, compares replacing its fleet of internal combustion engine (ICE) vehicles with PEVs based on each vehicle's purchase price, operating costs (i.e., fuel), and

[23] A more complete analysis would include the cost of the EVSE(s) necessary to charge the fleet of PEVs. However, no existing analyses include this cost.

potential as a revenue source (Gorguinpour, 2013). Neglecting to include additional infrastructure costs in such analyses, such as bidirectional EVSE and market participation fees, overlooks the fact that these costs are compulsory to entering into the wholesale market. Thankfully, the market participation example set by the DoD LA AFB project, which is in the process of purchasing V2G-enabled equipment and entering into fee-based contracts with the ISO, provides a rubric by which a more comprehensive economic analysis may be undertaken.

It is highly possible that, in order to cover the additional equipment and market participation costs, a PEV fleet may need to command a remuneration price from the CAISO above existing or historical rates. A revenue requirement such as this will make it difficult for PEVs to compete with existing frequency regulation service providers for bids in the wholesale market. To sort out the long-term viability of V1G/V2G, the following questions are addressed:

1. What bid price will ensure that equipment (in excess of conventional EVSE) and market participation costs are covered? Is it reasonable to anticipate receiving this price in the current CAISO market?

2. Frequency regulation is both the highest compensated and smallest wholesale ISO market. Even if PEVs were granted the lone ability to bid their resource into this market, how soon would this market saturate from V1G and V2G operations?

To answer these questions, this chapter first discusses the analysis methods, then presents the results, and finally frames the results with respect to the viability of integrating PEVs as market participants. The methods and results sections individually assess questions one and two listed above, and the discussion section incorporates the two in order to paint a holistic picture.

5.1 Analysis Methods

The analysis conducted in this chapter assumes that a market-ready PEV resource has similar characteristics to the existing market participating model of the DoD LA AFB: (1) a single fleet of PEVs that is organized by the fleet operator, and scheduled by the local utility, (2) each PEV requires its own V2G-ready EVSE, or its own traditional V1G EVSE,[24] (3) V1G fleets may operate in AC mode, providing a minimum power step of 10 kW, and V2G fleets must operate in DC mode, providing up to 30 kW, (4) all fleet PEVs are operated during normal business hours, and bid the remainder into the frequency regulation market (all hours except M-F 8a to 5p), (5) all PEVs are assumed to last 10 years; a break-even price implies the equipment and other fees are paid for over this time frame, and (6) market participation fees are covered by the fleet operator.

5.1.1 What is the break-even remuneration price?

The minimum remuneration price necessary to cover V2G equipment and market participation fees over the lifetime of a fleet is assessed by calculating the break-even price over a 10 year lifetime of PEVs and equipment for a fleet providing regulation down services, and for a fleet providing both regulation up and down. Once these remuneration prices are calculated, they are then compared with both the long-term, seasonal, and diurnal variations in the frequency regulation MCP presented in Section 4.4, and the current CAISO MCP rate. The sensitivity of the equipment costs is then explored by comparing the necessary break-even MCP with two thresholds of annual average MCPs from 2013 in the full CAISO territory. All potential V1G/V2G projects follow the participation guidelines of the

[24] All existing and future fleets must purchase a conventional, V1G/single-directional EVSE in order to charge their PEVs. As such, only marginal costs to facilitate bidirectional charging are included. The marginal cost of the V2G-ready EVSE is the full V2G EVSE price less the full V1G EVSE price.

only existing model of market participation, the DoD LA AFB: (1) PEVs must be operated as a single fleet (the power from individual PEVs is unified under the control of a fleet operator), (2) the power capabilities of the PEV fleet must meet minimum ISO requirements of 500 kW and 10 kW power step, (3) the local utility is the power aggregator/scheduling coordinator with the ISO, and (4) all vehicles in the fleet are Nissan Leafs with 6.6 kW on-board chargers unless otherwise specified.

Estimation of current CAISO frequency regulation MCP.

In order to make a fair assessment of whether the break-even remuneration price calculated in this thesis can be anticipated on the wholesale market, a brief discussion of the historical frequency regulation remuneration prices in the full CAISO market territory (North and South regions) is first provided. Following the analysis from MacDonald et al. (2012) presented in Section 4.4, two trends are calculated to describe a reasonable expectation for the value of the MCP in today's CAISO market.

1. *Average Hourly MCP:* For the full CAISO service territory, the average, minimum, and 90th percentile of each hour's MCP values are calculated over all hours, binned by month, from December 2010 through November 2013.

2. *Seasonal and Diurnal Variation in MCP, 2013:* Binning the hourly MCP values by season and hour shows the dependance of the price on the time of day, and how this dependance changes seasonally. The MCP is binned into three hour intervals, and grouped for the winter and summer months between October 2012 and September 2013. Box plots, showing the minimum and 90th percentiles, 1st and 3rd quartiles, and average and median values of these trends for summer and winter months are calculated, to update the values shown in Figure 4.6.

Together, these two trends are used to determine a reasonable value for the current

MCP in the full CAISO frequency regulation market. The MCP values used to calculate these trends are for the regulation up market only. Although regulation up is typically compensated slightly more than regulation down (see Table 4.1), the present-day regulation up value, taken from the trends calculated above, is used as an upper bound for both up and down markets. Fleets that contract to provide V1G will need to determine if their break-even MCP is equal to or less than this value. Those that contract to provide V2G will need a break-even MCP that is equal to or less than twice this value, since they will sell their services in both the regulation up and down markets.

Equipment and participation costs.

Chapter 4 addressed how the equipment necessary to bring the PEV resource to market can be extensive (see Section 4.3). If PEVs wish to offer both regulation up and down, then a special bi-directional charging station is needed for each vehicle in excess of an already purchased conventional EVSE. Even if PEVs only enter into a regulation down contract with the ISO, where the ability to control the charging rate is essentially another way for the ISO to manage loads, market participation fees can be steep, especially for this type of small resource. This analysis accounts for the most significant costs involved with V2G equipment and market participation fees except the monthly fees for the Data Concentrator/Scheduling Coordination.

The market participation fees considered in this analysis include the monthly wholesale participation fee and the monthly energy communication network (ECN) connection fee, both per site. The monthly fees are levied by the CAISO to cover bulk power management and transmission of metering information via the secure network, respectively. The equipment costs include the marginal V2G EVSE per vehicle, and the ISO meter installation and certification per site. Although the price for the ISO meter installation and certification is likely to remain stable for the next decade (Hinchman & Trimark Associates, Inc., 2014),

the cost of the EVSE is likely to come down with time. The sensitivity of the results in this analysis to the EVSE cost is addressed at the end of Section 5.1.2. See Table 5.1 for a breakdown of the costs in this analysis.

Table 5.1: Market participation (recurring) and equipment (upfront) costs included in calculation and analysis of the VGI break-even MCP. Equipment costs are per vehicle (EVSE, charging station) or per site (ISO meter), and market participation fees are charged monthly per site. Note that, since this analysis addresses the marginal costs necessary to enable V2G services, it is assumed that the fleet operator has already included the cost of purchasing a V1G EVSE.

Market Participation fee [$/mo, per site]		Equipment cost [$ upfront]	
Wholesale market participation fee	$1,000[25]	V1G/V2G EVSE (per vehicle)	$0/$50,000[26]
ECN Connection	$500[27]	ISO Meter Installation and Certification (per site)	$28,000[28]

Economic accounting for future costs.

All periodic expenses are brought to present-day values using the equation for the time-value of money with a discount rate, $d = 5\%$:

$$\text{Net Present Value, } NPV = A \times \frac{(1+d)^n - 1}{d(1+d)^n}$$

[25]Source: MacDonald (2013)

[26]The only existing bi-directional EVSE is the GTIB-15, currently manufactured as a prototype by Princeton Power Systems. The base price for the GTIB-15 is $55,000 (less installation, networking, and shipping) (Loc & Princeton Power Systems, 2014). The average price for a conventional single-directional EVSE (V1G-ready) marketed to fleet operators is on the order of $5,000. The base price for the ChargePoint CT4011-GW Pedestal Single 7.2 kW charging station is $5,000 (less installation, networking, and shipping). The marginal cost to equip a PEV fleet with V2G capabilities is the cost of the V2G EVSE less that of the V1G EVSE, or $55,000 less $5,000.

[27]Source: MacDonald (2013)

[28]Source: Hinchman & Trimark Associates, Inc. (2014)

where

$$
\begin{aligned}
NPV &= \text{Net Present Value of lifetime costs, } [\$] \\
A &= \text{annual cost } [\$] \\
d &= \text{discount rate } [\%] \\
n &= \text{project lifetime [years]}
\end{aligned}
$$

Break-even price to cover marginal V1G/V2G costs.

This section discusses the methods that were used to calculate the break-even annual average MCP to cover the equipment and market participation costs outlined in Table 5.1 for a 10 year lifetime of the PEVs in the fleet. The revenue that the PEV fleet has the potential to earn depends on three parameters: (1) power rating, (2) size of fleet (number of vehicles), and (3) annual contract hours. The break-even price will be different depending on whether the fleet contracts to provide regulation down alone (V1G), or both regulation up and down (V2G), because the equipment prices are different, and V1G is limited in the power rating it can provide. The break-even annual average MCP, in units of $/MW-h, is calculated for both scenarios as follows:

$$
\begin{aligned}
\text{MCP } [\$/\text{MW} - \text{h}] &= A^I \times \frac{1000}{B \times C \times D} \\
A^I &= NPV \times \frac{d(1+d)^n}{(1+d)^n - 1}
\end{aligned}
$$

where

$$
\begin{aligned}
MCP &= \text{annual average Market Clearing Price, } [\$/\text{MW} - \text{h}] \\
A^I &= \text{discounted average annual revenue needed, 10 year baseline, } [\$] \\
B &= \text{annual hours of operation per vehicle, } [\text{h}] \\
C &= \text{number of vehicles} \\
D &= \text{power rating, } [\text{kW}] \\
NPV &= \text{NPV of lifetime costs, } [\$] \\
d &= \text{discount rate } [\%] \\
n &= \text{project lifetime [years]}
\end{aligned}
$$

Two scenarios were explored using this calculation:

1. **V1G-only mode:** This fleet only contracts to provide regulation services in the regulation down wholesale market. Two parameters are varied in this mode – *size of fleet* and *annual contract hours*. *Power rating* is held constant at 6.6 kW.

   (a) *Size of Fleet:* To meet the 500 kW instantaneous power requirements, at least 76 PEVs are necessary. Results are shown for a fleet of 40 to 1000 PEVs with a constant annual contract hours value of 6,400, in order to facilitate a comparison with the fleet that operates in V2G mode.

   (b) *Annual Contract Hours:* Vehicles are considered fully available to provide regulation down services outside of normal business hours (8a – 5p, Monday through Friday). This works out to nearly 6,400 hours annually. Vehicles may, however, be available to provide services during business hours. To account

for this discretionary use of the resource by the fleet operator, this parameter is varied from 6,400 to 8,500 hours annually with a constant fleet size of 80 PEVs.

(c) *Power Rating:* All vehicles in the fleet are constrained to one-directional charging (the battery pulls power from the grid) in AC mode with the 6.6 kW on-board charger. Each PEV is connected to its own 7.2 kW EVSE[29] to capture the full 6.6 kW power flow.[30]

2. **V2G mode:** This fleet contracts to provide regulation services in both the regulation down and regulation up wholesale markets. All three parameters are varied – *size of fleet, annual contract hours,* and *power rating.*

   (a) *Size of Fleet:* To meet the 500 kW instantaneous power requirements, roughly 40 PEVs are necessary at the average power rating of 15 kW for the V2G-capable EVSE. Results are shown for a fleet of 40 to 1000 PEVs, where the power rating is held constant at 15 kW, and the annual contract hours value is held constant at 6,400.

   (b) *Annual Contract Hours:* As with the **V1G mode**, this parameter is varied from 6,400 to 8,500 hours annually. The fleet size is held constant at 40 vehicles, and the annual contract hours value is calculated from these values at 10, 20, and 30 kW.

   (c) *Power Rating:* All vehicles in the fleet are capable of providing two-directional charging (the battery pulls power from, or pushes it to, the grid) in DC mode. The Princeton Power Systems GTIB-15 bi-directional CHAdeMO charging sta-

[29] The ChargePoint CT4011-GW Pedestal Single charging station was used for this analysis; most conventional charging stations that are rated at 7.2 kW are priced similarly, around $5,000.

[30] Although each vehicle has the capability of pulling at most 6.6 kW from the grid, the fleet operator can manage the PEVs in bulk to provide a minimum power step of 10 kW.

tion can provide up to 50 kW of power in DC mode (MacDonald, 2013). To minimize the effects of battery wear from deep cycling, the annual average MCP is calculated at 10, 20, and 30 kW (to maintain the operational regulation of 10 kW power steps). Annual contract hours are varied from 6,400 to 8,500, and the fleet size is held constant at 40 PEVs.

Sensitivity to V2G EVSE cost.

The purchase price of the V2G-enabled EVSE is likely to come down in the next decade. To capture the effect this parameter has on the annual average MCP needed to break even, three "idealized" fleet scenarios are compared with two bounds for current MCP, where only the price of the V2G EVSE is varied.

The idealized fleet scenarios are: (1) a V1G fleet of 80 PEVs, operating 6,400 hours a year; (2) a V2G fleet of 40 PEVs, operating 6,400 hours a year at 15 kW each ("small fleet"); and (3) a V2G fleet of 400 PEVs, operating 6,400 hours a year at 15 kW each ("large fleet"). The first two scenarios are meant to illustrate the minimum possible entry requirements for market participation, while the third scenario demonstrates economies of scale for an order of magnitude larger V2G fleet.

These three scenarios are compared with two boundary values for the MCP in the full CAISO territory in 2013: (1) the maximum annual average MCP; and (2) the "restricted schedule" annual average MCP. The maximum annual average MCP is the average of the most lucrative 6,400 hours in 2013. The "restricted schedule" averages the MCP from the 6,400 hours that coincide with the proposed business schedule of the LA Air Force Base V2G project, or the 6,400 hours outside of 8a-5p, Monday through Friday, in 2013. These boundary values are meant to illustrate the likelihood that a fleet operator will be able to secure the necessary revenue, depending on when market participation occurs.

5.1.2 When will fleet vehicles saturate the regulation market?

The number of PEVs that will be necessary to saturate the CAISO frequency regulation market is estimated from the CAISO's projections of the maximum regulation requirements under 20% RPS (2012) and 33% RPS (2020) (Helman, 2010). These projected power requirements, in MW, are converted to number of PEVs as follows:

$$\text{number of PEVs} = \frac{\text{Power Requirement, [kW]}}{0.73 \times \text{PEV Power Rating, [kW]}}$$

where the PEV Power Rating, for a fleet providing both regulation up and down (V2G), is equal to 15 kW, and the scaling factor of 0.73 accounts for the potential unavailability of the PEVs during normal business hours, 8a – 5p Monday through Friday, following the fleet specifications from Section 5.1.1.

The estimated projections of the number of PEVs necessary to saturate both the regulation up and down markets are then compared with PEV market penetration projections for the CAISO service territory and California from multiple sources, including the fractional contribution from fleets. These comparisons are meant to illustrate the rapidity with which this niche market could saturate from PEV bid sales alone, assuming that all current regulation service providers exit the market.

5.2 Results

This section covers the results of the analysis. To address the questions presented in the beginning of this chapter, estimates for the following parameters are calculated: the current MCP for the CAISO frequency regulation market, the break-even annual average MCP

to cover V1G costs for a fleet providing regulation down services, the break-even annual average MCP to cover V2G costs for a fleet providing regulation down and up services, sensitivity to the V2G EVSE price, and the number of PEVs necessary to saturate today's market and the future market with 33% RPS in place.

5.2.1 Break-even remuneration price versus current CAISO MCP

This section presents the results of estimating the current MCP for frequency regulation in the CAISO wholesale market, the necessary break-even annual average MCP to cover equipment and market participation for a fleet providing V1G, the necessary break-even annual average MCP for a fleet providing V2G, and a discussion of the sensitivity of the these results to the V2G EVSE purchase price.

Current CAISO frequency regulation MCP.

The MCP in the frequency regulation market in the full CAISO service territory (North and South combined) has been decreasing substantially since the early 2000s (see Table 4.1). In the early 2010s, the MCP held steady around $10/MW-h for a couple of years (slightly higher for regulation up, and lower for regulation down). Since late 2011, however, the regulation up average hourly MCP dropped to roughly $5/MW-h (see Figure 5.1). This price fluctuated between $5 and $10/MW-h in 2012, and has steadily remained at or below $5/MW-h through present day operations. In general, regulation up is compensated slightly higher than regulation down (MacDonald et al., 2012). The price trend for the regulation up MCP, shown in Figure 5.1, suggests that an optimistic estimate of the annual average MCP for either regulation up or down would be roughly $5/MW-h. Providers that bid into the regulation down market will then be compensated, on average annually, $5/MW-h, whereas those that bid into the regulation up and down markets will be compensated $10/MW-h for

securing their services in two parallel markets.

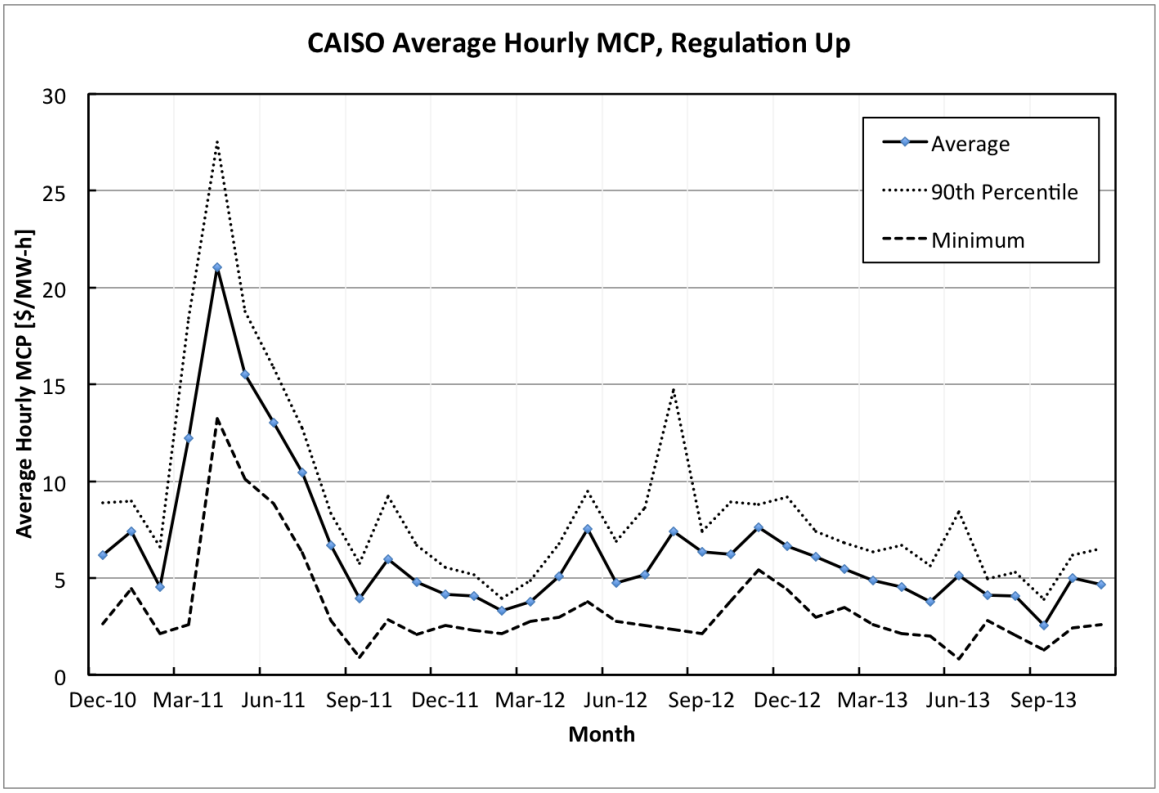

Figure 5.1: Historical frequency regulation MCP (regulation up) for the CAISO (North and South regions together) from December 2010 through November 2013. The historical MCP for regulation up in the CAISO market has decreased substantially in the last half-decade, holding steady around $5/MW-h for the last two years. As with the NYISO (Figure 4.5), this reflects a downward trend in frequency regulation MCP among most ISO/RTOs.

Although the MCP has become relatively stable over the last two years at $5/MW-h, it fluctuates dramatically throughout the day, and depending on the season. Figure 5.2 shows the dispersion of hourly MCP for the regulation up market throughout the day in the winter months (October 2012 through March 2013) and in the summer months (April 2013 through September 2013). As with the previous year in the CAISO South region frequency regulation market (see Figure 4.6), the winter months see a bimodal peak in the MCP in the early morning (6a-9a) and late evening (6p-9p), while the summer months see a strong

single peak in the MCP in the early afternoon (3p-6p). These peaks likely result from power loads influenced by the work week in the winter months, and from an increased demand for cooling units in the summer months. If fleet operators manage the charging and discharging of their PEVs according to this schedule, they may have the potential to secure an average MCP on the order of $7 – $11/MW-h in the winter months, and roughly $10/MW-h in the summer months. Careful management of the fleet's frequency regulation capabilities alongside peak demand periods could nearly double the remuneration price for this service.

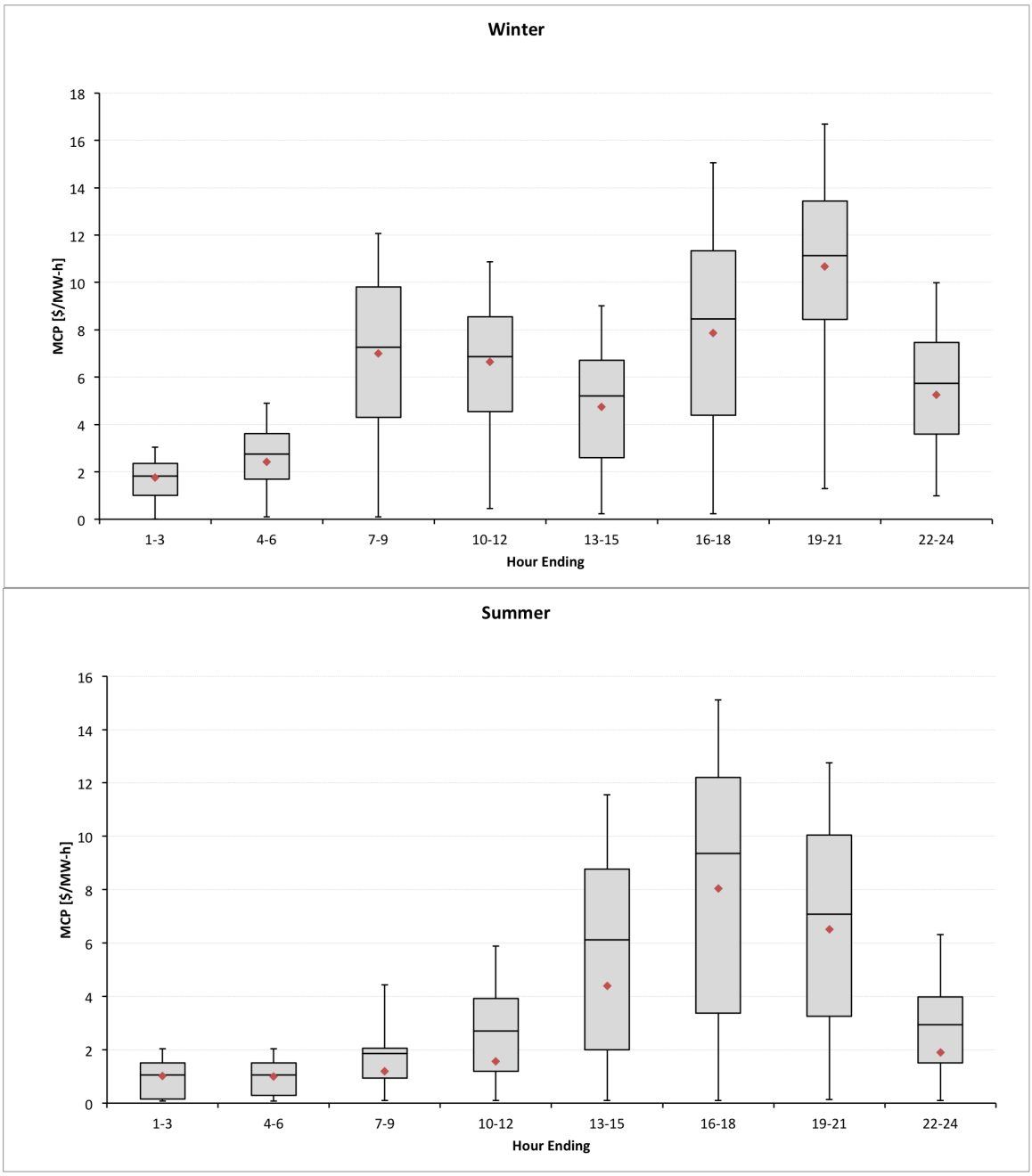

Figure 5.2: Seasonal and daily variability in the MCP for CAISO frequency regulation (full service territory) in 2013. The seasonal and daily variability follows similar trends to those in 2011 (South region), where a spike in MCP during summer afternoon hours can be attributed to demand for cooling units, and a higher MCP during winter morning and evening hours is due to shifted demand for power, including lighting (see Figure 4.6). The red dots and the solid horizontal lines in these boxplots correspond to the median and average MCP for each three-hour interval, respectively.

Break-even price to cover marginal V1G/V2G costs.

To cover the monthly costs of the CAISO wholesale market participation and the ECN connection, as well as the initial investments of the V2G EVSE (per vehicle, for V2G fleets only) and the ISO meter installation and certification (see Table 5.1 for a full list of costs included in this analysis),[31] PEV fleet aggregators will need to secure a significant bid price on the CAISO frequency regulation market. These estimates must be interpreted as a first-order low end estimate, as they do not include scheduling coordination for the data concentrator (see Marnay et al., 2013) and infrastructure upgrades including EVSE installation. Other estimates for costs of the PEV-to-ISO connectivity to the aggregator for a fleet of roughly 800 – 1,000 PEVs, such as an on-site server, network infrastructure, engineering, SCADA software, and project management, can be as high as $70,000 per site (Fell et al., 2010). The results of the two scenarios explored in this thesis, a V1G fleet (regulation down only), and a V2G fleet (regulation up and down) are presented below, along with the sensitivity of the break-even annual average MCP to the V2G EVSE purchase price.

1. **V1G: One-directional AC charging, regulation down market participation, normal fleet-specific EVSE (6.6 kW rating)**

   Most PEVs are capable of on-board charging at 6.6 kW (see, for example, the proposed fleet of Nissan Leafs in Marnay et al. 2013). In order to meet the frequency regulation market requirement of 500 kW minimum instantaneous power, at least 76 vehicles are required for a fleet that is limited by this charging capability in AC mode.

   For a fleet of 76 PEVs providing regulation down outside of normal business hours (8a – 5p Monday through Friday, approximately 6,400 hours per year), an annual average MCP of roughly $6.40/MW-h is necessary to cover the marginal V1G-specific

[31] These are costs above that of the PEV and its single-directional charging station EVSE, or the marginal costs to enable market participation.

infrastructure and basic market participation costs, shown as the dashed line in Figure 5.3. If this fleet of 76 PEVs is able to provide regulation down services for greater than 6,400 hours in a year, as shown by the solid line in Figure 5.3, this price can be relaxed by only $0.50/MW-h for every additional 1,000 annual hours. As the purchase of a V1G-capable EVSE is compulsory to any fleet (and not included in this analysis), increasing the size of the fleet reduces the necessary annual average MCP substantially. This highlights the impact of steep market participation fees on a small distributed power resource. A fleet of 100 PEVs, operating 6,400 hours a year, will need to secure at least $5/MW-h on average annually. As we will see at the end of this section, the selection of the 6,400 operational hours has a significant impact on the necessary annual average MCP.

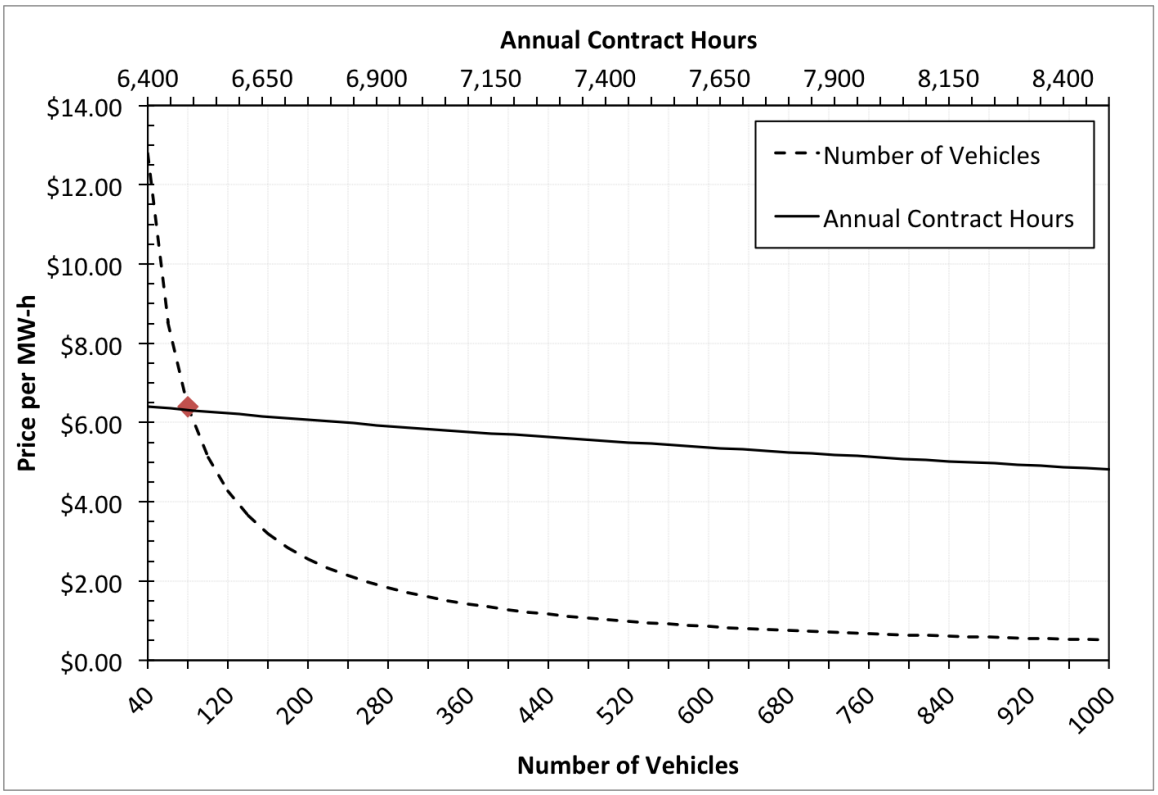

Figure 5.3: Break-even annual average MCP for a V1G fleet as a function of number of vehicles (dashed line, annual contract hours held constant at 6,400) and annual contract hours (solid line, number of vehicles held constant at 76). The red dot on the dashed line corresponds to a fleet of 76 PEVs. A fleet of this size, operating in V1G-mode and outside normal business hours, can reasonably expect to break even on its market and equipment investment with an annual average MCP of at least $6.40/MW-h.

2. **V2G: Two-directional DC charging, regulation up and down market participation, V2G EVSE (up to 30 kW rating)**

   A fleet of PEVs that wishes to bid into both the regulation up and down markets requires special EVSE that can often cost an order of magnitude greater than that of conventional EVSE (see Table 5.1). This V2G-equipped EVSE must be capable of pulling and pushing power between the PEV and the grid, and do so in DC mode in order to provide a premium of higher power throughputs. The only EVSE that is

currently being used to enable this service by PEVs on the CAISO wholesale market can provide power up to 30 kW, but will likely provide 15 kW on average.[32] At this power rating, a fleet of 40 PEVs can easily meet the 500 kW minimum instantaneous power requirement of the CAISO.

Figure 5.4 shows the remuneration price requirements of a V2G fleet for this type of specialized infrastructure and market participation. A fleet of 40 PEV, each providing 15 kW of regulation up and down to the CAISO, must secure roughly $36/MW-h for this service in each market (solid line in Figure 5.4), independent of the annual contract hours above those outside normal business hours (greater than 6,500 hours per year). This will yield an annual average MCP revenue of roughly $72/MW-h.

The largest parameter that relaxes the necessary annual average MCP for the fleet is the power rating, followed distantly by the size of the fleet. A fleet of 40 PEVs operating for 6,500 hours annually, each at 30 kW, can break even on its V2G infrastructure and market participation investment if it secures a annual average MCP of $18/MW-h in each regulation market. For every additional 500 PEVs that are added to this fleet, the necessary combined price can be relaxed by roughly $3/MW-h.

If the fleet can provide 20 kW per PEV on average, this price raises to $27/MW-h (in each market) for 40 PEVs, dropping by roughly $4/MW-h for each additional 500 PEVs added to the fleet.

A small fleet that meets the minimum entry requirements (40 PEVs, operating at 15 kW for 6,500 annual hours), must secure at least $36/MW-h in regulation up and down markets independently.

[32]The LA AFB V2G pilot project plans to provide V2G grid support services at a rate of 15 kW per vehicle, on average, in order to alleviate negative effects from deep battery cycling (Marnay et al., 2013; MacDonald, 2013).

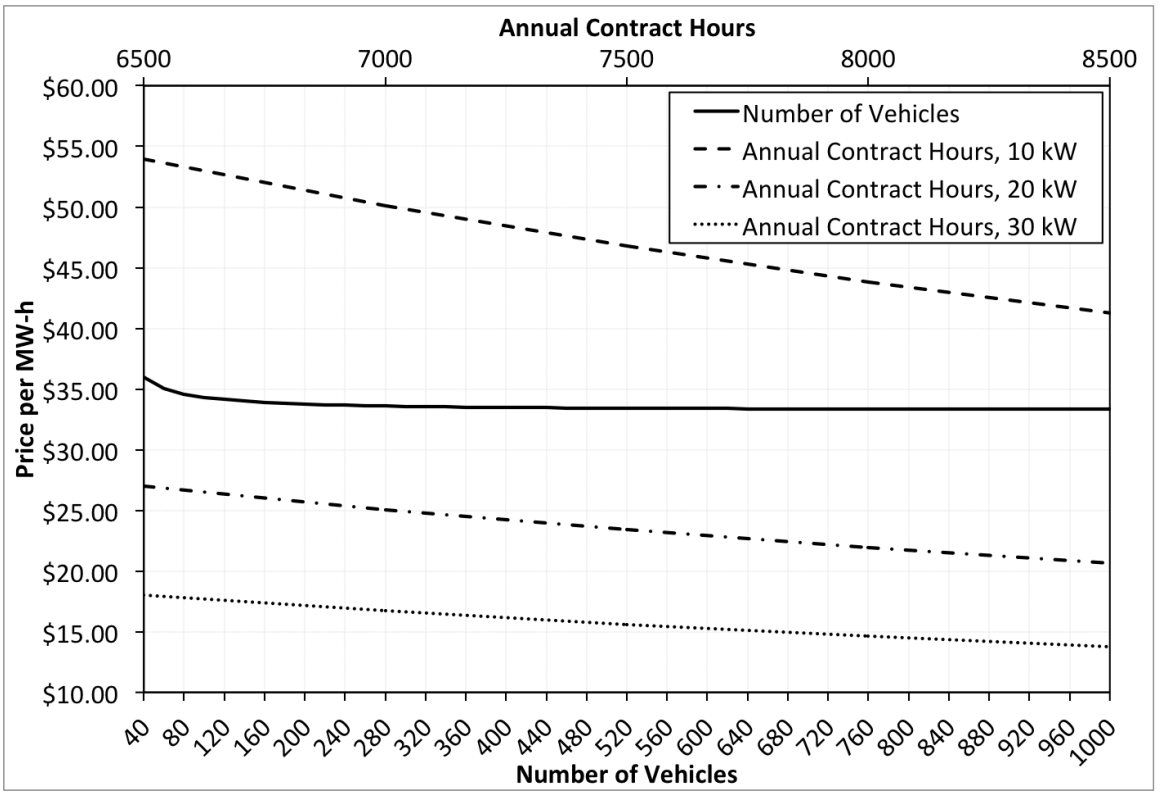

Figure 5.4: Break-even annual average MCP for a V2G fleet as a function of the number of vehicles in the fleet (solid line, annual contract hours held constant at 6,400, power rating held constant at 15 kW), annual contract hours (dashed lines, number of vehicles held constant at 40), and power rating (dashed lines; 10 kW, 20 kW, and 30 kW from top to bottom, number of vehicles held constant at 40). The annual average MCP reflected in this graph, or price per MW-h, corresponds to the necessary bid price in the regulation up and down markets individually; a break-even price of $35/MW-h means that, on average, a bid price of $35/MW-h is necessary in the regulation up and down markets individually, and the fleet operator will collect $70/MW-h from both markets together. Above roughly 80 PEVs, the fleet size has little effect on the break-even annual average MCP for a fleet operating in V2G-mode. The largest contributor to reducing the break-even annual average MCP is the power rating.

Sensitivity to V2G EVSE cost.

The annual average MCP that is needed to break even on a market participation investment is sensitive to the purchase price of the marginal V2G EVSE equipment, shown in Figure 5.5. In order to determine the likelihood of this investment paying for itself, all sce-

narios are compared with the maximum annual average MCP and the restricted schedule annual average MCP.

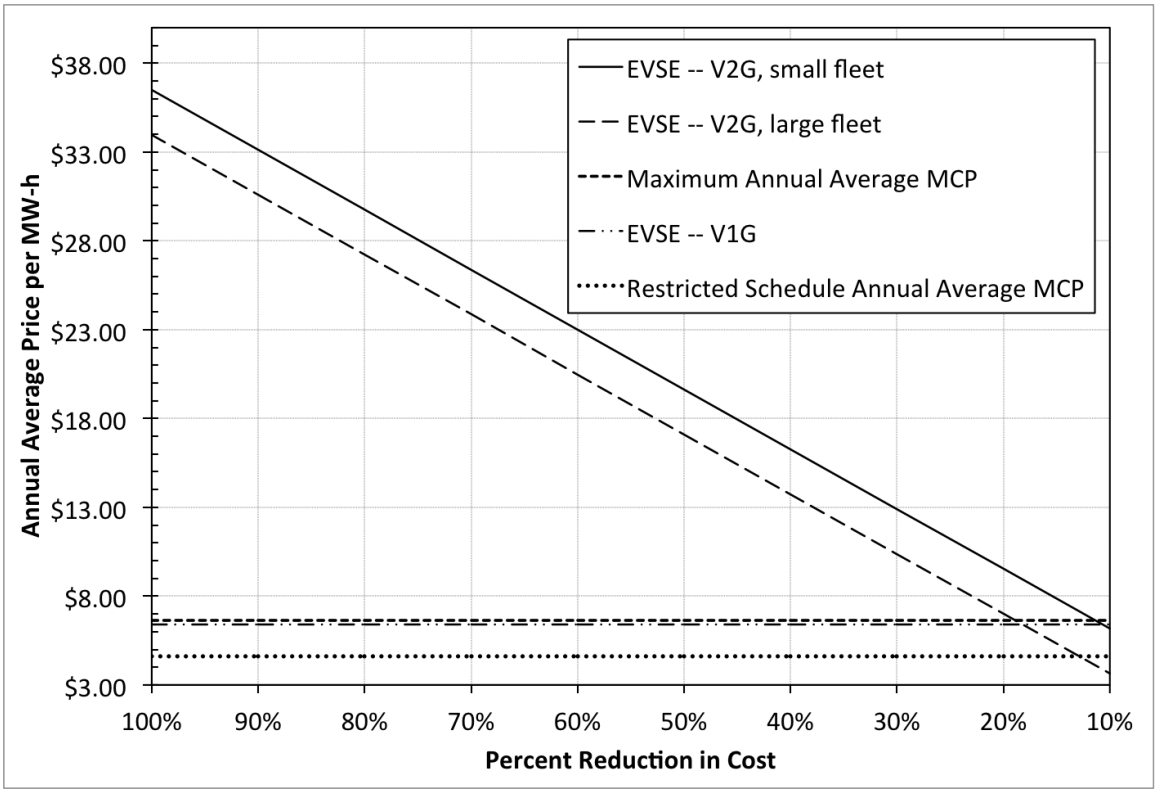

Figure 5.5: Break-even annual average MCP as a function of the percent reduction in cost of the V2G EVSE with boundary comparisons for the maximum and restricted schedule annual average MCP. The break-even annual average MCP is highly sensitive to the V2G EVSE cost for fleets that operate in both the regulation up and down markets. The maximum annual average MCP ($6.60/MW-h) and the restricted schedule annual average MCP ($4.60/MW-h) illustrate the power of optimizing the hours of market participation. A V1G fleet (80 PEVs, 6,400 hours annual participation) may break even on its marginal equipment and market participation costs (necessary annual average MCP of $6.40) if the fleet operator can select the most lucrative hours in a year. A small V2G fleet (40 PEVs, 6,400 hours annual participation, 15 kW) can expect to secure the maximum annual average MCP only once the V2G EVSE is reduced to 10% its current price. A large V2G fleet (400 PEVs, 6,400 hours annual participation, 15 kW) can expect to break even on its investment with a restricted schedule once the V2G EVSE is reduced to roughly 12% its current price.

The maximum annual average MCP, $6.60/MW-h, corresponds to a gross revenue of

roughly $42,400 in the highest compensated 6,400 hours of 2013. The restricted schedule annual average MCP, $4.60/MW-h, corresponds to a gross revenue of roughly $29,500 from the hours outside of 8a – 5pm, Monday through Friday in 2013. These two boundaries illustrate the economic value in optimizing a fleet's hours of participation in the market, and the limitations of a restricted schedule for revenue generation.

A V1G fleet, comprised of 80 PEVs participating for 6,400 hours annually, must secure at least $6.40/MW-h on average annually in order to break even on its marginal equipment and market participation investment. This may be possible if the fleet operator is able to bid into the market during the most lucrative hours, but will not be possible for a fleet with a market participation schedule that is a second priority to normal business operations.

A small V2G fleet, comprised of 40 PEVs participating for 6,400 hours annually at 15 kW each, can only break even on its marginal V2G equipment and market participation investment if the V2G EVSE is reduced to 10% its current price and the bid schedule is optimized for the most lucrative 6,400 hours in the year. A large V2G fleet, comprised of 400 PEVs participating for 6,400 hours annually at 15 kW each, can break even on its investment under a restricted participation schedule if the V2G EVSE is reduced to roughly 12% is current price. A large fleet can more easily relax its requirements for a break-even annual average MCP because it is able to bid a much larger storage capacity resource into the regulation market. This demonstrates the difficulty that very small resources have in entering the existing market.

5.2.2 When will fleet vehicles saturate the regulation market?

It is impractical to assume that PEVs will be able to monopolize the frequency regulation markets, as existing service providers will not wish to terminate their existing contracts.

That said, the requirement for regulation services will grow substantially in the coming years, but not necessarily enough to surpass both the supply of PEVs and the supply of power services from existing providers. Figure 5.6 shows both the maximum regulation requirements for each season in 2012 and 2020 and the number of PEVs, each operating at 15 kW, that would satisfy these requirements.

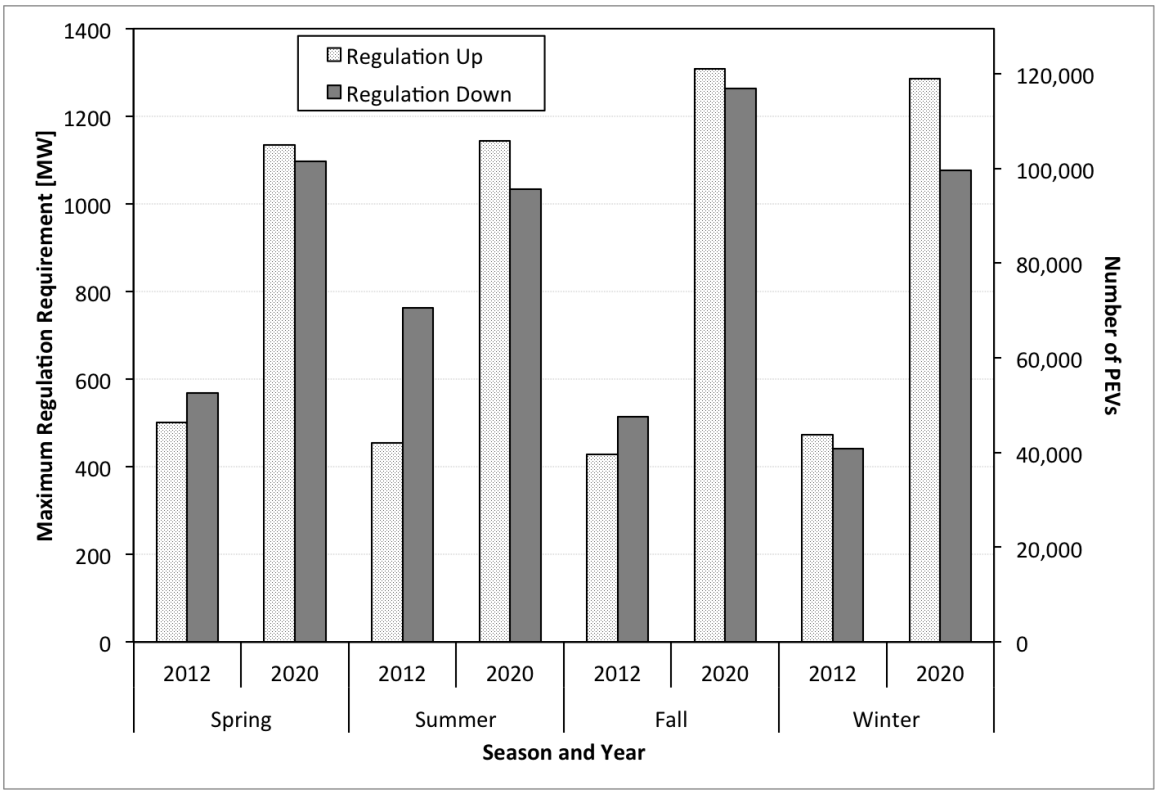

Figure 5.6: Maximum regulation requirements, and the number of PEVs in California needed to meet these requirements, for the CAISO by season through 33% RPS. Between 2012 (20% RPS) and 2020 (33% RPS), the maximum requirements for regulation by the CAISO (left axis, Helman (2010)) will nearly double for spring and summer months, and more than double for fall and winter months. The number of PEVs (right axis) correspond to the minimum number of PEVs in California, each connected at 15 kW, necessary to saturate these regulation requirements.

The need for regulation services will grow between 2012 and 2020 as a direct result of incorporating renewable power (see Chapter 2), where the requirement in 2012 is a result of

a 20% RPS, and that in 2020 of a 33% RPS (Helman, 2010). At today's regulation requirement level, roughly 50,000 PEVs, each connected at 15 kW for 6,400 annual hours, could satisfy all the grid's regulation needs. By 2020, the number of PEVs to fill all regulation requirements would need to jump to almost 120,000.

If PEVs were granted uncompetitive access to secure bids in the wholesale regulation market, would there be enough vehicles to saturate the need for this service? Figures 5.7, 5.8, and 5.9 shed some light on the forecasts for PEV market growth in both California and the CAISO service territory over the next decade.

Although President Obama's 2011 State Of The Union call to secure one million PEVs on the road by 2015 has recently been relaxed (Obama, 2011; Rascoe & Seetharaman, 2013), a recent analysis of the projections for PEV growth by ISO from KEMA suggests that the CAISO territory will see the most rapid increase in PEVs (see Figure 5.7). If one million domestic PEVs are on the road by 2015, nearly a third of these will be within the CAISO service area. Of these, 30,000 PEVs are projected to be operated in fleets (Fell et al., 2010).

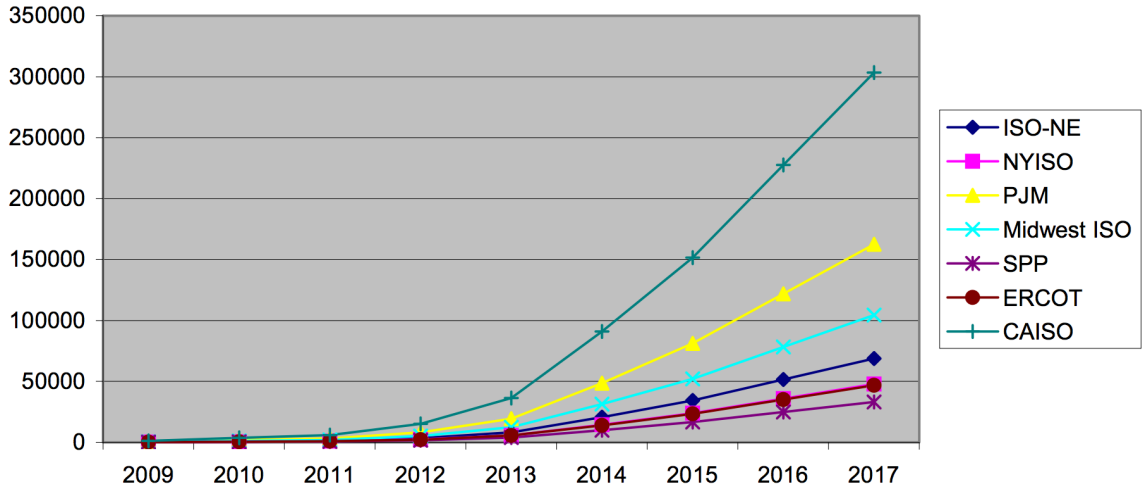

Figure 5.7: KEMA projections for PEV growth, by ISO, through 2017. Growth targets for PEVs in the CAISO service area are expected to dwarf those of other ISO service territories. From Fell et al. (2010).

Another recent analysis, prepared by the UCLA Luskin Center for the Southern California Association of Governments, suggests an even steeper growth rate for California (see Figure 5.8). This analysis draws upon the results from KEMA shown in Figure 5.7, and incorporates a parallel study done by TIAX. The most conservative estimates for PEV forecasts in California suggest there will be between 300,000 and 600,000 PEVs on the road by 2020. Of these, nearly 30,000 will be full battery-electric vehicles, and most likely to come equipped with larger batteries, and higher powered on-board chargers (Ben-Yehuda, 2012).

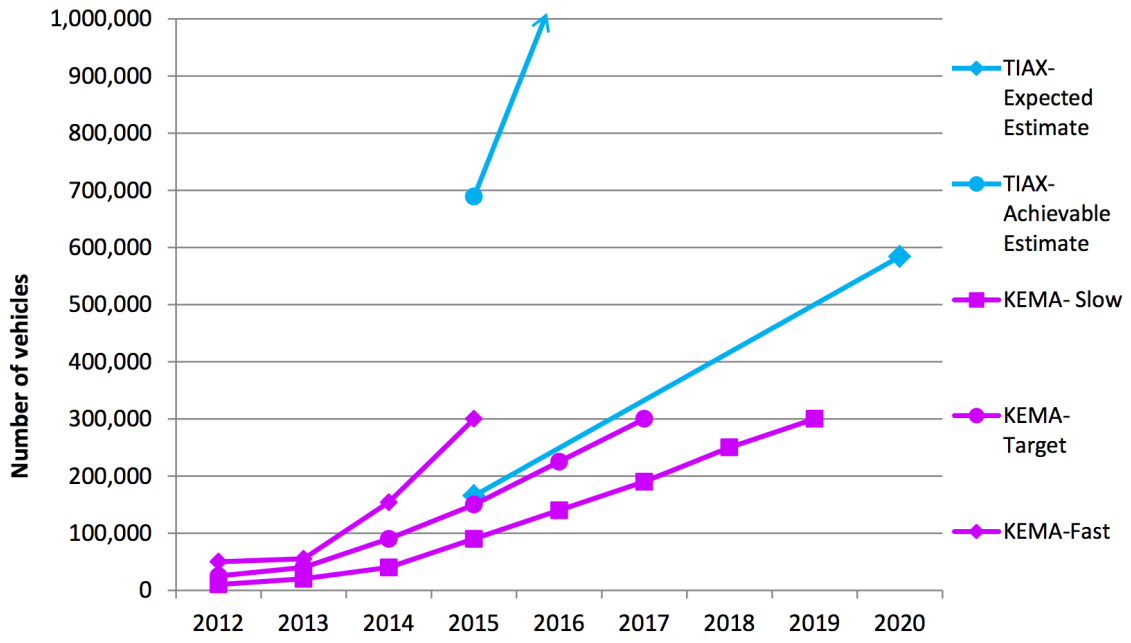

Figure 5.8: Cumulative PEV forecasts for California from analyses by KEMA and TIAX. KEMA conservatively estimates that nearly 300,000 PEVs will be on the roads in California by 2020. Many of these PEVs will be outside the CAISO service territory. From Ben-Yehuda (2012).

Navigant Research now forecasts that national sales of PEVs will grow at a compound annual growth rate of 18.6% between 2013 and 2022 (see Figure 5.9). California is expected to see the largest growth in PEV ownership, at nearly 100,000 PEVs annually by 2020 (Alexander & Gartner, 2013).

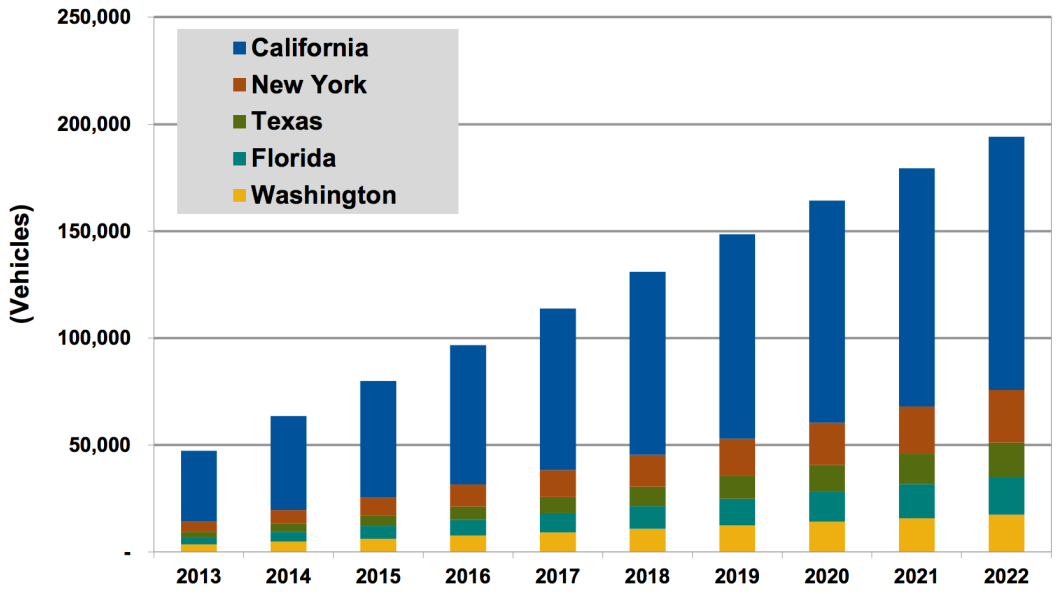

Figure 5.9: Annual Light Duty PEV Sales, Top Five States, United States: 2013-2022. By 2022, annual sales of PEVs in California will top 100,000 (blue stacked bar). From Alexander & Gartner (2013).

The results of these three studies suggest that PEVs are projected to grow in market penetration rapidly over the next decade. In a 2014 report, the U.S. Bureau of Transportation Statistics estimates that there will be 300,000 PEVs on the road in California by 2020, with 6,000 of these in fleets (U.S. Bureau of Transportation Statistics, 2014). If all 300,000 PEVs both intend to participate in the market and are able to successfully compete for a bid alongside existing service providers, this would nearly saturate the wholesale regulation market. However, if this technology remains feasible only for fleets, market saturation is not likely to be an issue.

5.3 Discussion

The analysis in this thesis addresses the economic viability of PEV fleets as distributed short-term energy storage on the CAISO frequency regulation wholesale market, with the

inclusion of specialized infrastructure and market participation fees necessary to facilitate V2G and V1G services. This is quantified with two parameters: (1) the break-even annual average MCP for V2G or V1G services, and (2) forecasted demand for regulation services compared with anticipated supply of PEVs. This section discusses the results presented in Section 5.2, and frames them with respect to the anticipated pathway for PEVs as a distributed energy storage resource.

5.3.1 Will the current MCP allow PEV fleet operators to break even on their investment?

In order to ensure that the necessary infrastructure and market participation fees (see Table 5.1) are covered by revenue from the CAISO wholesale market, PEV fleets that actively supply V1G services must secure at least $6.40/MW-h in the regulation down market (Figure 5.3), and those that supply V2G services must secure at least $36/MW-h in the regulation up and down markets independently (Figure 5.4). The current average hourly MCP, however, is $5/MW-h, rarely exceeding $7/MW-h (Figure 5.1). Moreover, this value has been falling substantially over the last decade (Table 4.1), where the $5/MW-h value has only been stable over the last two years (Figure 5.1). In general, these additional costs – which are compulsory to participation in the market – will make it difficult for PEV fleet operators to see a return on their investment from selling their battery storage capabilities to grid operators.

If managed properly, PEV fleet operators may be able to secure MCPs as high as $10-$15/MW-h during the highest compensated hours of the day for a handful of days (Figure 5.2). During the winter months, the hours between 6a and 12p see average MCPs of $7/MW-h, with peaks of $12/MW-h, and the hours between 3p and 9p can be compensated roughly $10/MW-h, and up to $17/MW-h. During the summer months, the hours between

12p and 9p are compensated at $7/MW-h on average, and can peak at $15/MW-h between 3p-6p.

Is it practical to assume that PEV fleets can take advantage of select hours? This may be practical, but will depend entirely on the operational needs of the vehicles in the fleet. Moreover, the total number of these peak compensation hours is minimal (see the "Maximum Annual Average MCP" boundary condition in Figure 5.5). For the economic analysis in this thesis, it was assumed that PEVs were dispensable for grid services outside of normal business hours, i.e., outside the hours of 8a to 5p, Monday through Friday. During the winter months, the highest compensated window is from 6p to 9p, where the MCP is $11/MW-h average, and $17/MW-h peak. However, between the hours of 9p and 6a, the MCP drops significantly, averaging around $5/MW-h. During the summer months, the highest compensated window is from 3pm to 6p, at $9/MW-h average, and $15/MW-h peak. For the majority of the hours the fleet is available – between 10p and 8a – the MCP hovers between $1-$3/MW-h. A typical daytime-operational fleet may be able to secure higher MCP bids during some portion of the day in the winter and summer months, but the majority of the dispensable hours do not align with these peak hours, especially in the summer months.

The total cumulative hours that yield these higher compensation rates are minimal. If a fleet operator had the capability to secure bids in the 6,400 most lucrative hours in 2013, the annual average MCP for this year would be only $6.60/MW-h (Figure 5.5).[33] Restricting the PEV fleet to market participation outside of normal business hours yields a much lower, and more realistic, annual average MCP, at $4.60/MW-h.

Even if PEV fleets could arrange to take advantage of peak remuneration hours, are

[33]Sufficient foreknowledge of the MCP is a persistent exogenous variable in current analyses. Although idealized scenarios may show that these prices will yield sufficient revenues in many cases, they are impractical given current predictive capabilities (Zarkoob et al., 2013; Goebel, 2013; Donadee & Ilić, 2012b).

they likely to cover their market participation investments with the MCP available during these hours? V1G-capable PEV fleets can relax their annual average MCP requirements in two ways – by increasing the fleet size, and by increasing the annual market contract hours (Figure 5.3). Increasing the fleet size to at least 110 PEVs (30 additional PEVs) may reduce the necessary annual average MCP to less than $4.60/MW-h, or the annual average MCP from a restricted, non-business hours, schedule of operations. Increasing the annual contract hours has little effect on relaxing the necessary annual average MCP. Fleet operators must also weigh the economics of purchasing and installing conventional EVSEs for normal operation, especially considering that current V1G/V2G analyses neglect to include basic charging infrastructure costs.

V2G-capable PEV fleets can relax their MCP requirements in three ways – by increasing the fleet size, by increasing the annual market contract hours, and by increasing the power connection (Figure 5.4). Increasing the fleet size has a comparatively small effect on reducing the necessary annual average MCP; the break-even price asymptotically approaches $33/MW-h for each regulation market. Increasing the annual contract hours can relax the necessary annual average MCP, but the effect is not sufficient to break even with current MCP rates, even for fleets that provide 30 kW of regulation services per PEV. The largest effect on reducing the necessary annual average MCP comes from operating each PEV at 30 kW. Fleet operators require $18/MW-h in each regulation market at this power level if they operate only outside business hours, and as little as $14/MW-h if they provide regulation services at all times. As with the V1G fleets, however, this price is only achievable for a narrow window of the day, both in the winter and summer months. Moreover, although battery degradation resulting from the increased frequency of shallow battery cycling that comes from participating in regulation services is typically an order of magnitude less than that from driving a vehicle (see Section 4.2.1), cycling a PEV battery at 30 kW is

no longer considered shallow cycling. Providing regulation services consistently at 30 kW may dramatically reduce the PEV's battery lifetime, and thus increase the fleet operator's costs over the lifetime of the vehicles, as these batteries will need replacement. The largest contributing factor to realizing a net-neutral investment comes from future reductions in the V2G EVSE equipment cost. If the price of the V2G EVSE is reduced by 88%, a relatively "large" fleet of 400 PEVs could reasonably expect to break even on its market participation and infrastructure investment at $4.60/MW-h (Figure 5.5).

It may be possible for a V1G fleet operator to break even on his or her market participation investment, but this requires careful, and sometimes impractical, optimization of contract bid hours. It will be difficult for a V2G fleet operator to break even on his or her V2G investment until the cost of V2G EVSE comes down by at least 90%, or the order of magnitude of current conventional EVSE charging stations. This cost parameter is the most likely to be reduced in the coming years, since the technology is still in its infancy. The ISO meter and installation fees ($28,000 per site, see Table 5.1), however, are expected to remain stable for the foreseeable future (Hinchman & Trimark Associates, Inc., 2014).[34] This suggests that, although PEVs represent a new source for electricity storage, the costs to individual participants to integrate with the power market may remain insurmountable unless subsidies are made available to soften the initial EVSE investment. As the frequency regulation MCP is unlikely to increase in the future, this application of electricity storage is likely to remain viable only for pilot projects until the V2G-enable EVSE costs come down substantially.

Policies and subsidies aimed at facilitating the adoption of both EVSE and advanced

[34]Incumbent thermal generators have a comparatively lower cost of supplying the regulation market because they can spread the fixed market participation costs over more production. This affords these existing service providers an economic advantage in continuing to supply the regulation market. See Lamble (2011) for further discussion of the cost recovery challenges to V2G/V1G services for advanced metering infrastructure.

energy storage exist, but the availability of funds is not reliably consistent. Table 2.1 summarizes the existing policies that will reduce the regulatory challenges of Vehicle-Grid Integration, but does not address potential sources of funding to facilitate this process.

The California Energy Commission's (CEC) annual investment plan for the Alternative and Renewable Fuel and Vehicle Technology program has been the most reliable source of funding for PEV charging station infrastructure (EVSE) for the past six years. Although fleet applications are a second priority to subsidizing residential EVSE, nearly $800,000 were allocated to nonresidential sites in the most recent award cycle, and $2.5 million were awarded to support the purchase of DC fast chargers (the closest analogue to V2G-enabled EVSE). Moreover, this program regularly earmarks funds for "emerging opportunities" such as V2G applications. In particular, the LA AFB V2G project was awarded $1 million (out of a possible $4 million) in 2013 to support the CAISO's interest in commercializing this grid service (Allen et al., 2013). Depending on the availability of funds each cycle year, this funding source may prove a crucial mechanism to facilitate V1G/V2G investments.

Thanks to its application for energy storage, V1G/V2G projects may be able to secure funding through energy storage program solicitations. The CEC recently advertised the availability of $6 million in a program opportunity notice to further the state's goal of "Developing Advanced Energy Storage Technology Solutions to Lower Costs and Achieve Policy Goals." In particular, electric vehicle charging is described as an eligible use case for customer-sited storage behind the meter (CEC, 2014). As with the previously described funding opportunity for charging equipment, this will benefit V1G/V2G projects most if it becomes a reliable source until the equipment costs are reduced by at least 90% (Figure 5.5).

5.3.2 Can PEVs saturate the frequency regulation market?

The frequency regulation market is small, but will at least double over the next decade (Figure 5.6). With more anticipated demand for the service from the rapid inclusion of renewable power sources, it may be reasonable to project that the MCP will recover within this time period to a level that allows V1G/V2G to become profitable for a short time period before equilibrating to the current MCP (Callaway, 2014; and forthcoming publication). This assumes, however, that there will not be fierce competition within the market for the additional anticipated bids.

One of the primary reasons that the frequency regulation MCP has been dropping substantially over the last decade, and will likely not increase in the near future, is due to the market weight of existing regulation service providers (Klauer, 2013). Current providers include thermal generators such as combustion turbines and combined cycle and steam turbines. Although the rapid cycling required by frequency regulation has been shown to cause substantial damage to these systems, the generator operators have a vested interest in retaining their share of this comparatively lucrative market; many thermal generating units bid as much at 16% of their capacity into the regulation market (Leitermann, 2012). This suggests that, even if the MCP recovers due to increased demand for regulation services, there will be strong competition to secure bids in this market.

Even if competition for current and future bids in the frequency regulation market were not an issue, it still remains the smallest market. If V1G and V2G are intended to provide substantial load shifting and energy storage services to the grid in order to facilitate the integration of intermittent renewable power sources (see Chapter 2), how rapidly would this comparatively lucrative market become saturated by PEVs? In other words, will the "lucrative" market saturate quickly, or before infrastructure and market participation in-

vestment cost reductions can support a lower MCP from other markets? Without a baseline for the timeframe of reduced market participation fees (which are not likely to reduce with time, as opposed to EVSE infrastructure costs), these costs are assumed to remain stable for the foreseeable future. A qualitative analysis of this question – can PEVs saturate the frequency regulation market, unimpeded by competition from existing providers – requires two parameters for consideration: (1) a projection of the number of PEVs that will satisfy demand for regulation (in 2012, at 20% RPS, and in 2020, at 33% RPS); and (2) the growth in PEV ownership, or the anticipated supply of this resource.

Between 2012 and 2020, the number of PEVs that would be necessary to satisfy all demand for regulation services in California must expand from roughly 50,000 to 120,000 (Figure 5.6). Although there are many different studies that forecast growth in PEV sales, even the most conservative suggest that the supply of PEVs in California will exceed 300,000 by 2020 (see Section 5.2.2). At least 10% of these, or 30,000 PEVs, are expected to be full battery-electric, with larger batteries and higher power on-board chargers. Roughly 2% of all light duty vehicles are operated in fleets, corresponding to 6,000 of the 300,000 PEVs on the road by 2020 (U.S. Bureau of Transportation Statistics, 2014). If all 300,000 PEVs participate in the regulation market by 2020, the market will be easily saturated. However, if market participation remains relegated to fleets, there is little reason to suggest that this market will suffer from saturation by PEVs.

There are three prevailing factors that will limit entry for PEVs to the regulation market: (1) the MCP is currently too low to cover marginal V2G-enabled EVSE; (2) market participation costs are substantial, and stable for the foreseeable future; and (3) the market is already dominated by existing service providers.[35] The equipment price for V2G-enabled

[35]These existing regulation service providers largely intend to retain their hold in the market, and have the market weight to prevent entry by new participants due to the cost advantage from sunk-cost investments in capacity to supply the regulation market (Klauer, 2013).

EVSE may come down in the future, but this parameter must be reduced by at least 88% to have any impact. Fleet operators that wish to contract their PEVs in the regulation down market (V1G) have the potential to break even on infrastructure and market participation investments, but these costs do not consider a number of additional fees, such as installation upgrades. Moreover, this requires the fleet operator to optimize bid scheduling for the most lucrative hours in the year, which is currently impractical. Until these obstacles are overcome, such as infrastructure funding opportunities through the CEC, V1G and V2G are likely to remain relegated to pilot projects for the foreseeable future.

6 CONCLUSION

This thesis traced the potential role that PEVs may play in facilitating the integration of intermittent renewable energy sources with the power grid. Although large banks of power storage will be necessary to shift load from renewable sources in the long-term, the CAISO and other grid operators have identified fast-responding units capable of increasing quantities of storage as necessary to bridge this pathway. PEVs are seen as a potential key contributor to this endeavor, and policies that facilitate both the inclusion of energy storage on the grid, and the compensation of this resource to small distributed units (fleets of PEVs), are gaining traction.

Pilot projects are currently underway testing both the ability for PEVs to provide short bursts of power to the grid in the frequency regulation market and initiating regulatory frameworks that will pave the way for large-scale adoption in a way that is satisfactory to all stakeholders. In order to attract the distributed energy storage resource that PEVs represent, the arrangement between PEV owner/operator, PEV aggregator (often the utility), and grid wholesale market must generate revenue for the PEV owner.

The frequency regulation market is the highest compensated of all ancillary service markets; this has lead researchers over the last decade to calculations that suggest the PEV owner may see annual revenues on the order of $2,500 (Kempton & Tomić, 2005a). However, these calculations neglect to include the equipment (EVSE) and market participation fees necessary to secure a contract in the frequency regulation market.

This thesis finds that, when the costs of purchasing V1G/V2G charging station equipment, ISO metering, and monthly market participation fees are included in a simple life-cycle economic analysis, the currently available market clearing price for the service of frequency regulation is insufficient to ensure the investment will break even over its life-

time. The primary obstacle to the economic viability of this service is the purchase price of V2G-enabled EVSE, but the CEC currently has two independent funding programs that can help to reduce this cost.

If interest in this application of energy storage is to grow, fund support is needed to help vehicle owners cover costs associated with V2G-enabled EVSE until the purchase price is reduced by an order of magnitude and to reduce the cost of market participation fees. Fleets that operate only in V1G-mode (bidding only into the regulation down market) are not plagued by the steep EVSE investment costs of V2G fleets, as they can potentially rely on traditional EVSE to interact with grid operators. Even without this cost, V1G fleets can barely manage to break even on their investments to provide energy storage services because the market participation fees (largely dominated by the ISO meter installation and certification and monthly ISO fees) are designed for resources at a larger scale than a fleet of roughly 100 vehicles. The amount of energy provided for regulation services from small resources like PEV V2G/V1G fleets is economically inefficient relative to these fixed cost elements. Future analyses of V1G and V2G services should address the possibility of subsidies for ISO market fees, or the potential for a new classification of reduced market fees for these and other small resources.

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