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ATTACHMENT A

The Utility Role in Supporting Plug-In Electric Vehicle Charging

Staff Issues Paper
Energy Division
California Public Utilities Commission
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Introduction

This paper discusses utility role and boundary issues associated with plug-in electric vehicle (PEV) charging. Much of the paper focuses on metering issues, but topics related to other aspects of the utility-customer boundary and streamlining of the charging infrastructure installation process are also addressed.

The paper is organized into five parts:
1. General Metering Background
2. PEV Metering Arrangements for Single Family Homes
3. PEV Metering Arrangements for other Customer types
4. Utility Role in PEV Adoption
5. Conclusions, Recommendations, and Questions

Throughout this document, the use of the term 'customer' refers to either the utility accountholder or the charging company that is providing charging services (i.e., the entity that is responsible for the electricity bill for a particular location *or* account).

Section 1: General Metering Background

This section provides background information on metering and how it relates to PEVs, including: PEV charging equipment, utility metering, and meter cost information; party responses to the metering questions posed in the Order Instituting Rulemaking 09-08-009; and several related issues such as PEV charging equipment interactions with the smart grid and the Low Carbon Fuel Standard (LCFS) requirements.

1.1 PEV Charging Equipment

Certain parties expect that Level 2 electric vehicle service equipment (EVSE) will be the preferred charging equipment for residential and commercial PEV users in the long-term.[1] The following equipment and permits are needed for customers who install PEV Level 2 charging equipment at their home or business.

- Adequately-size service panel: Each electricity customer has a service panel that divides the electric circuits and includes a circuit breaker to safely manage electricity consumption.
- Adequate wiring to the charging location: customers will need wiring of the appropriate gauge installed to serve their EVSE. This wiring will extend from the panel to the EVSE.
- EVSE equipment: charging equipment designed to safely manage the voltage used to recharge the PEV battery, meeting applicable electric code requirements.
- City/County Permits for any electrical or land use changes.

Customers using Level 1 charging equipment will likely not need to install EVSE or need panel changes. These customers may only need wiring from the panel to a traditional 3-prong outlet. Separate EVSE equipment may be unnecessary for customers using low voltage levels to fuel their vehicle.

Customers installing direct current (DC) charging equipment will need additional wiring and charging equipment. Panel upgrades and additional permitting requirements are likely for DC charging installations at residential and commercial service locations.

An additional hardware component is the electric meter. The following sections explain the functions and characteristics of an electric meter.

1.2 Metering Basics: What can and can't a meter do?

In its simplest form, an electric meter measures the current going through a circuit at a specific location in the power system, most frequently at the point of service to a customer account.[2] Although parties ascribed numerous functions to the meter, the meters' basic functions are limited to:

- Measuring the accumulated current going through a given wire;
- Measuring the voltage or potential applied to the load;
- Converting these measurements to energy usage or consumption in watt hours;

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[1] PG&E opening comments at p.5.

[2] Energy Policy Research Institute (EPRI), "Accuracy of Digital Meters" May 2010 (p. 2)

- Recording the watt hour readings under different time intervals;
- Storing meter data internally; and
- Communicating stored data (wirelessly or over wires).

The AMI meters currently being deployed by the three investor-owned utilities (IOUs) cannot do the following:

- Measure or store data for specific subloads;
- Respond to demand response or load management signals[3]; or
- Calculate or process billing information.

Meters have four characteristics:

- *Accuracy:* Meter 'accuracy' is defined as the variance of the demand measurement versus the demand delivery. For example, a meter with 1% accuracy would produce meter measurements that may vary by +/- 1% of the actual load delivered. Smaller accuracy ratings reflect greater measurement precision. Electricity meters generally range in accuracy from 5% to .25%. Mechanical electricity meters traditionally used by utilities have 2% accuracy, while the Advanced Meter Infrastructure (AMI) meters currently being installed by California's IOUs are rated at .25% accuracy.
- *Data measurement granularity:* Current AMI meters being installed in each IOU territory can measure a single customers usage under different time intervals. Each IOUs' AMI meter is required to track load at a minimum granularity of hourly intervals.[4]
- *Data Storage Capability:* Meters have memory cards that can store past usage data. AMI meters generally store one day to one month of data.[5]
- *Communication functions:* A meter needs some method to communicate its usage data to the utility. Traditionally, meters required manual, on-site reading by utility meter readers. The AMI meters currently being installed by California's three major IOUs have embedded software that wirelessly communicates usage and other information to the utility back office. Most meters can be configured to communication with the utility and/or with a Home Area Network (HAN). Communication with a HAN could occur through one of several communication protocols (Zigbee, Z-Wave, HomePlug, or others).

The performance of utility-owned meters is verified by the utility. The utility is also responsible for 'sealing' their meter after it has been installed and responding to customer complaints regarding its accuracy. Non-utility owned meters are verified by the California Department of Food and Agriculture and sealed by the local County Sealer.[6]

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[3] If a HAN is used, the HAN devices may be programmed to respond to load management responses. Although the meter could facilitate this communication, the meter itself would not be acting to these messages.

[4] KEMA Report, 2009.

[5] Ibid.

[6] Verbal communication with Matt Stevens of the California Department of Food and Agriculture, Division of Measurement Standards on Aug 24th, 2010.

1.3 Meter Costs

Meter cost depends on the functionality of the meter and the installation cost. According to a KEMA report on CSI metering requirements, meter hardware can range in cost from $35 (for a simple socket meter with no remote communication functionality) to over $1,000 for meters capable of advanced submetering and sophisticated communication functions.[7] KEMA estimates that the average residential solid-state AMI meter costs about $151, which includes remote communication functions and installation cost.

1.4 Party Perspectives on PEV Metering Issues

Several themes that emerged from the October 2009 written responses to questions posed in the Aug 24, 2009 AFV rulemaking are summarized below.

Consider different functionalities that can be included in the meter. Parties assumed a range of functions that should be included in the meter, including:

- Customer price signals (Environmental Coalition)[8]
- Load management functionality (Environmental Coalition, University of Delaware, General Motors, SDG&E, PG&E)[9]
- TOU load tracking ability (Tesla and PG&E)[10]
- Vehicle to grid functionality (Tesla)[11]
- Two way communication functions (PG&E)[12]
- Neighborhood level communication functions to avoid local distribution impacts (TURN)[13]
- Ability to charge for highway/excise taxes (Environmental Coalition)[14]
- Net metering to facilitate vehicle-to-grid power flow (University of Delaware)[15]

Address the EV/Smart Grid nexus. Many parties recognized a need for the meter to be able to communicate with the smart grid (Coulomb, Environmental Coalition, General Motors, SDG&E, TURN).[16] While PG&E and SDG&E thought that PEV meters should rely on the smart grid, Better Place pointed out that enabling the communication and functionality necessary to support PEV load management need not be dependent on smart meters.[17]

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[7] Ibid. (page 7-6).
[8] Environmental Coalition opening comments at p.16.
[9] Environmental Coalition opening comments at p. 16, University of Delaware opening comments at p. 2, General Motors opening comments at p. 2, SDG&E opening comments at p. 8, PG&E opening comments at p. 4.
[10] Tesla opening comments at p. 2 and PG&E opening comments at p. 4.
[11] Ibid.
[12] PG&E opening comments at p. 4.
[13] TURN opening comments at p. 5.
[14] Environmental Coalition opening comments at p. 16, SDG&E opening comments at p. 8.
[15] University of Delaware opening comments at p. 2.
[16] Coulomb Technologies opening comments at p. 10, Environmental Coalition opening comments at p. 16, General Motors opening comments at p. 2, SDG&E opening comments at p. 8, TURN opening comments at p. 4.
[17] Better Place opening comments at p. 5, PG&E opening comments at p. 5, SDG&E presentation at the March 16th Joint Agencies workshop.

Consider LCFS credit issues. Numerous parties suggested that direct metering would be needed for measuring LCFS credits.[18]

Allow for flexibility for metering requirements. Almost half of the parties that filed comments to the OIR encouraged the Commission to allow flexibility in the metering options that would be made available to PEV users. San Diego Gas and Electric (SDG&E), Sacramento Municipal Utility District (SMUD), Interstate Renewable Energy Council (IREC), AeroVironment, Environmental Coalition, Better Place and the University of Delaware all suggested that the market is at such an early stage of its development that narrow metering requirements might be quickly outmoded by new technologies or market challenges.[19] Coulomb and The Utility Reform Network (TURN) both thought that different customer types could benefit from different metering arrangements, requesting the Commission accept multiple metering arrangements for PEVs.[20] Pacific Gas and Electric (PG&E) and Tesla suggested that the Commission should allow for flexibility within defined technological and communication constraints.[21] One party, Southern California Edison (SCE), indicated that the current practices regarding meter investments are appropriate to facilitate early market adoption.[22]

1.5 Metering Requirements

In order to understand what metering functionality might be required for PEV meters, it is useful to review the metering requirements that the CPUC has used in other customer or technology contexts. Metering arrangement issues have been addressed by prior Commission decisions in the four contexts discussed below.

Advanced Meter Initiative (AMI). The May 18, 2005 Assigned Commissioner Ruling in the AMI proceeding established six broad functional requirements for smart meters:

- Support price responsive tariffs;
- Collect hourly usage data;
- Allow customer access to data;
- Be compatible with customer education, energy management, customized billing and complaint resolution applications; and
- Be compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability.[23]

The AMI meters being deployed by each IOU meet or exceed each of these requirements.

[18] SMUD opening comments at p.3, Mitsubishi opening comments at p. 3, and BP America opening comments at p.6.
[19] SDG&E Opening Comments at p. 7, SMUD opening comments at p. 2, IREC reply comments at pp. 2-3, AeroVironment opening comments at p. 2. Environmental Coalition opening comments at p.16, University of Delaware opening comments at p.2, Better Place opening comments at p.2, Division of Ratepayer Advocates (DRA) opening comments at p. 7, Tesla opening comments at p. 2.
[20] Coulomb opening comments at p.4 and TURN opening comments at p. 4.
[21] PG&E opening comments at p. 4 and Tesla opening comments at p. 2.
[22] SCE opening comments at p. 9.
[23] CPUC Decision 05-09-044.

California Solar Initiative. The CSI program uses different metering requirements depending on the incentive requirement used. For photovoltaic (PV) systems receiving a performance-based incentive, CSI requires that a 2% accuracy meter be used. For systems receiving a capacity-based incentive, the CSI program requires that a 5% meter be used. In California and most other states, PV programs require that performance-based incentives have metering that is equal to or better than what is required of capacity-based incentives.[24] Meters are not required to communicate wirelessly. Metering service organizations are required to submit metering data to the utility; however, they are allowed to use whatever remote or manual data collection method they choose.

Direct Access. Direct Access customers are not required to have a utility-owned meter. Instead, the service provider or the customer can provide the meter used for billing. This meter, though not provided by the utility, is used by the utility to calculate transmission and distribution charges, while the energy provider uses the meter to calculate generation charges. The Commission recognizes that third party intermediaries for DA customers may install and operate metering equipment, provided that it meets utility standards.[25] For instance, the meters must measure load on hourly intervals. Energy Service Providers (ESPs) must be able to store 12 months of usage data, but this data does not need to be stored on the meter. In addition, the utility can inspect the meter if they suspect that it is faulty.[26]

Self-Generation Incentive Program (SGIP). SGIP provides financial incentives to customers that install on-site distribution generation. To receive a production incentive, customers are required to use meters with 2% accuracy or better.

1.6 Meters and Smart Grid Communication Functions

Some parties implied that PEV electricity usage needs to be measured separately by an AMI enabled meter. While the meter can play a role in facilitating smart grid communication, a smart meter is not essential to enable a PEV or a customer-owned EVSE to participate in smart grid communications.

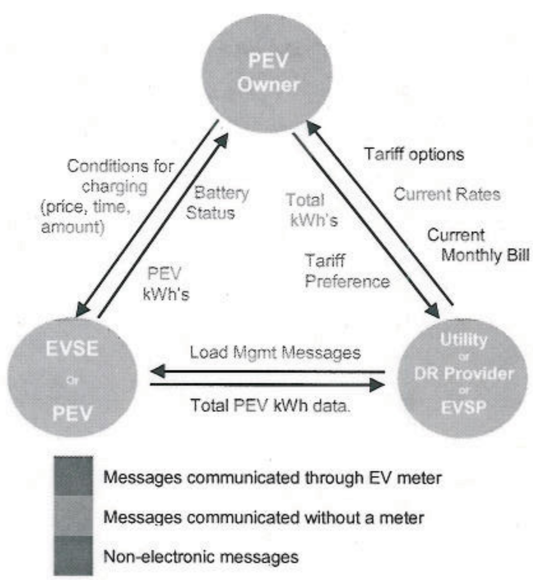

Figure 1. Messages Needed for PEV Charging

[24] Ibid.

[25] CPUC Decision 95-12-063.

[26] PG&E Tariff Rule 22. SCE Tariff Rule 22 and SDG&E Tariff Rule 25.

The following are examples of data and information exchanged between entities involved in the PEV charging process:

- PEV load
- Unique tariffs and billing arrangements for PEVs
- Remote management/control of PEV charging
- Smart vehicle charging communication

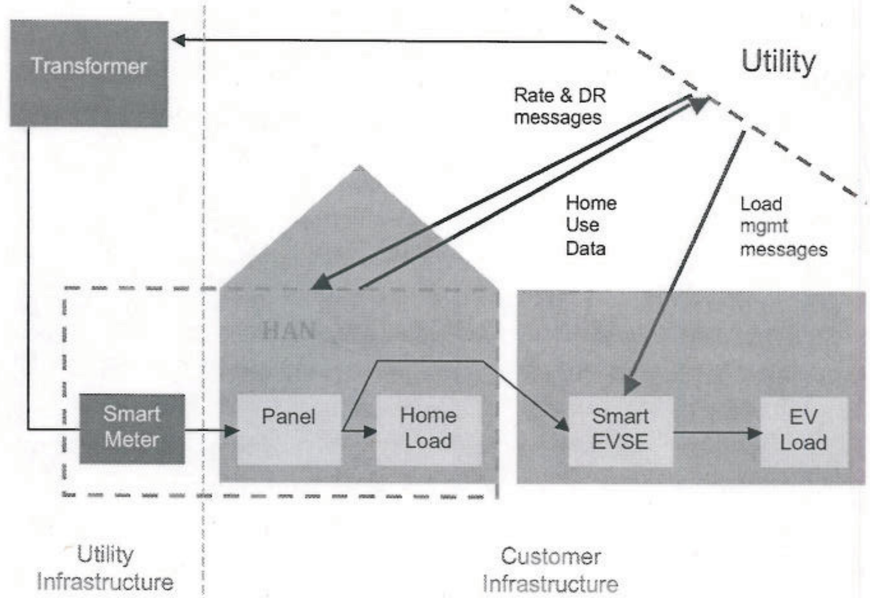

Figure 2. Smart Grid Communication without Separate PEV Metering

Metering communication is a subset of the broader communication that occurs between the utility, the customer and the electric vehicle. Figure 1 is a simplified representation of the information exchanged between these entities.

It is not necessary to have a second AMI meter coordinate all of the communication functions for a PEV identified above. The PEV meter need only communicate the electricity usage.

Other types of remote control devices in the HAN, EVSE or even the PEV can accomplish many or all of the load management control and smart charging communication functions.

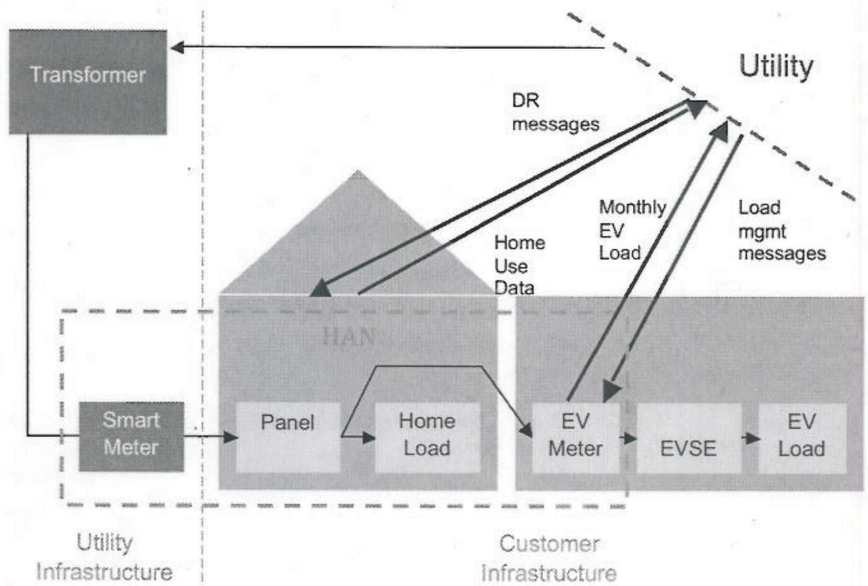

Figure 3. Smart Grid Communications with Separate PEV Metering

Figure 2 shows how these messages are communicated within a residential house using whole house metering. In this figure, the EVSE is responsible for receiving any demand response (DR) messages. All other communications functions can be achieved with out the need for an AMI compatible meter, if the EVSE is AMI-enabled.

Figure 3 shows what communication functions could work when a second meter is AMI compatible. In this example, the PEV meter is assumed to be a submeter of the primary meter. This submeter is responsible for communicating PEV usage data to the utility and receiving load management messages.

In its metering report for CSI, KEMA addressed the need for CSI meters to be AMI compatible. KEMA evaluated three options for CSI participants: no AMI integration, AMI compatible meters owned by the customers, and AMI meters owned by the utility. KEMA found that requiring AMI meters for PV systems would result in increased costs for PV owners but would allow for consistent record keeping.[27] KEMA also found that allowing customer owned meters to connect to AMI would allow customers to take advantage of technology changes. However, KEMA noted that third party electric vehicle service providers (EVSPs) could leave the market, raising subsequent maintenance issues for the AMI-compatible meters that the third party EVSPs installed.[28]

1.7 PEV Metering Requirements under the LCFS and Other Regulations

Parties identified the need for two possible regulatory requirements that may require direct metering of PEVs: LCFS credits and electricity fuel excise taxes. No excise taxes that apply to electricity currently exist in California. However, Executive Order S-01-07 directed the California Air Resources Board (ARB) to establish the LCFS regulation by 2011. The LCFS requires fuel deliverers (at specified points of regulation) to reduce the carbon intensity of fuels used in California by 10% from a baseline applicable to reformulated gasoline and diesel fuels.[29] Currently, alternative fuels below the established baseline carbon intensity may generate surplus LCFS credits. These credits may be traded at a price determined by the supply and demand for the credits. The regulation will go into effect in 2011.

ARB's regulation assigns LCFS credits to a third party provider, where applicable. If there is not a third party provider, the load serving entity that provided the fuel is assigned the LCFS credit. Customers can set up contractual agreements that require the third party EVSP or the utility to turn over the LCFS credits to the customer.[30]

In its Final LCFS Regulation Order, ARB required that electricity fuels used for transportation can only receive LCFS credits if they are "direct metered." Prior to 2015, ARB will allow regulated entities to claim LCFS credit provided they demonstrate that

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[27] KEMA, 2009. Final Report for the CSI Meter and Market Assessment Project.
[28] Ibid.
[29] Air Resources Board, 2010. Low Carbon Fuel Standard Program Background.
[30] Air Resources Board, 2010. Final Regulation Order.

they have a credible alternative to direct metering.[31] After 2015, all credits for residential charging, public access charging, and fleet charging require some form of direct metering (although ARB has not specified how this will be achieved).[32] ARB's regulation does not specify the metering frequently or level of accuracy required for LCFS credits.

[31] EV users that use direct metering prior to 2015 will not have the option of using the estimated methodology to calculate their LCFS credits.
[32] Ibid.

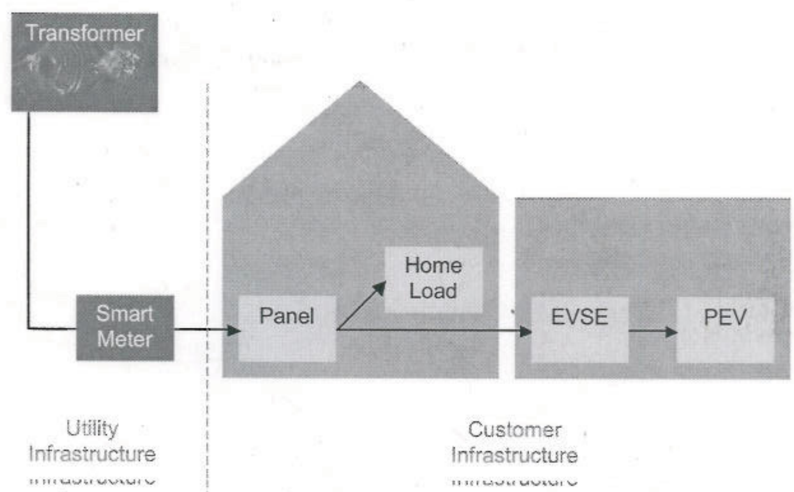
Section 2: Identified Approaches to Metering PEV Load in Single Family Homes

This section addresses PEV metering options for single family homes. Generally, PEV charging is expected to occur predominantly at the customer's home. Three metering options are described in this section, and they are evaluated against four criteria (installation impacts cost impacts, communication functionality, and billing flexibility).

2.1 PEV Metering Options

Three general approaches have been identified that can be used for metering PEV load in a single family residence: single metering, submetering, or separate metering. Each of these approaches can be used by each customer type, though unique customer contexts may require additional specifications. In its presentation at the March 16th Joint Agencies workshop, PG&E identified three similar metering options.[33] (Except for a handful of submetering exceptions described in Section 4.1, California's IOUs currently offer PEV customers the choice of either using a single or separate metering arrangement.)

Single Metering. All PEV load is counted as part of the total house load, and is not separately measured. This approach (which is used for virtually any other new appliance purchased by a household) is sometimes referred to as 'whole house' metering.



Separate Metering. PEV load is measured and billed separately from the rest of the customer load, using a dedicated revenue grade meter. The PEV load is essentially charged to a separate account from the rest of the customer's load, though the accounts can be aggregated onto one bill. Separate metering is sometimes referred to as 'parallel metering.'

Figure 4. Single Metering for a Residential Home with PEV

[33] PG&E Presentation, March 16th Joint Agencies EV Workshop.

During the 1990s, separate metering was often accomplished using a dual meter adapter. The dual meter adapter reduced the number of utility visits during the installation process and avoided the need for some panel upgrades.[34] However, staff understands that SCE will no longer support dual meter adapter installations, because the dual meter adapter is not United Laboratories (UL) approved.

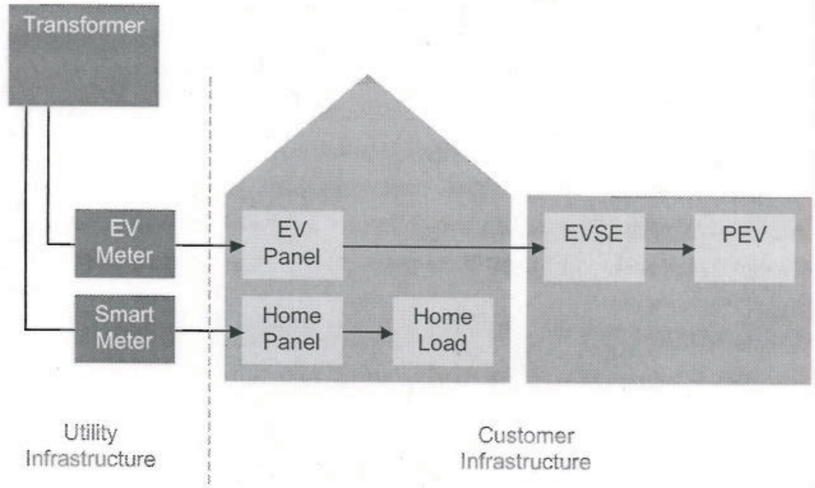


Figure 5. Separate Metering for a Residential Home with an PEV

Submetering. PEV load is measured by a meter installed between the main meter and the EVSE that acts as a submeter for the PEV load. This meter measures PEV load as a subset of the entire load, while the original customer meter measures the entire customer load. For billing purposes, the PEV meter load needs to be subtracted from the main meter load to avoid double-counting the PEV kWhs. Submetering is sometimes referred to as 'subtractive metering' or 'series metering.'[35]

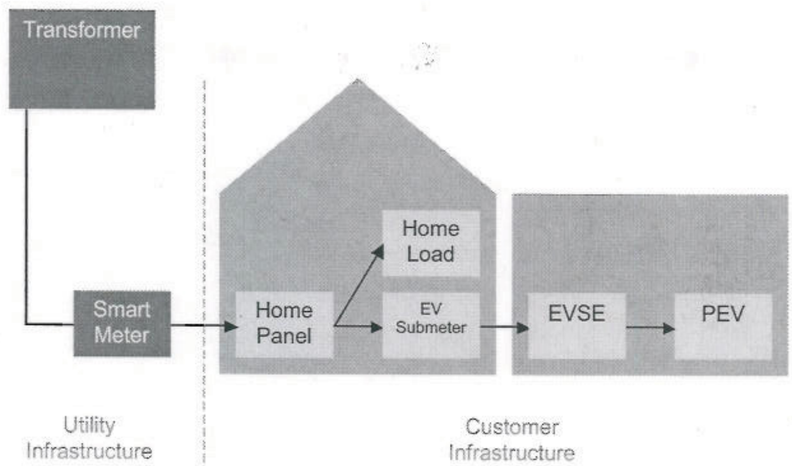


Figure 6. Submetering for a Residential Home with an PEV

These criteria are explored in the following three subsections, evaluating the metering options from the perspective of a single family house.

2.2 PEV Metering Arrangement Criteria

PEV metering arrangements can be evaluated based on the four criteria described below.

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[34] Verbal communication from Enid Joffe (CEO, Clean Fuels Connection) on August 26, 2010.

[35] The term 'series metering' may be considered misleading because the meter is not in series per the electrical definition of the term.

Installation Impacts. Metering requirements may add additional steps to the EVSE installation process. Several parties thought that utilities should use PEV metering arrangements that minimize the installation requirements for EVSE. General Motors expressed the concern that metering arrangements should introduce "neither an inconvenience nor a cost to residential customers and that the installation should be integrated with the EVSE installation."[36] The installation process has already been identified by stakeholders as a potential obstacle to PEV adoption. In the March 16th Joint CEC and CPUC workshop on EVSE installation, several parties (including PG&E and Clean Fuel Connection) identified 'hand-offs,' or transitions/sign-offs between parties, as the primary source of installation delays, rather than the actual labor time associated with the installation.[37] According to Clean Fuels Connection, the average installation took 35-45 days, while the actual work to install the equipment took only about 4 hours.[38] PEV installations that require new meters or changes to the existing meter will require a visit from utility personnel, adding additional 'hand-offs' to the EVSE installation process. Panel upgrades are the source of several additional hand-offs and considered by Clean Fuel Connections to be the biggest driver of installation costs.[39]

Cost. Different meter arrangements require different equipment and total labor time. SMUD argued that the "financial interests of customers" must be factored into the PEV metering requirements in order to avoid stifling adoption.[40] A major source of time and labor costs for EVSE installation is the need to upgrade the panel size. According to Clean Fuel Connection, the average cost of an installation – excluding the charging station and service upgrades expenses - in 2009 was $1,671, and the median cost was $1,494.[41]

EVSE installation may require distribution system upgrades under high PEV penetration rates. However, these costs do not appear to be linked to the metering arrangement. Distribution upgrades are dependent on the customer's panel size and their neighborhood transformer load. Although single metering does not change the 'nameplate' amperage demanded by a household, it can increase the coincident demand on a transformer, impacting the quality of power for customers on that transformer. So although PEV load will be the same regardless of how it is metered, single metering and submetering may not signal to the utility the need for an upgrade evaluation the way that the permitting and installation of separate meter may.

Communication Functionality. The metering arrangement will impact the PEV load information available and the control utilities and customer have over that load. Metering arrangements with fewer communication functions do not necessary prevent the use of remote load management functions. As stated previously, the lack of a unique PEV meter does not preclude a PEV or an EVSE from participating in DR or other load management

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[36] General Motors opening comments (p.2).
[37] PG&E and Clean Fuels presentations, March 16th Joint Agencies EV Workshop
[38] Clean Fuel Connection Presentation, March 16th Joint Agencies EV Workshop.
[39] Clean Fuel Connection Presentation, March 16th Joint Agencies EV Workshop.
[40] SMUD opening comments (p. 3).
[41] Clean Fuel Connection Presentation, March 16th Joint Agencies Workshop.

programs. However, meters that lack these functions will require additional equipment components to participate in DR programs.

Billing Flexibility. A separate meter enables a PEV to be separately billed from the rest of the customer's load. Separate billing allows customers to choose the tariff schedule for their PEV usage separate from the tariff schedule used for their home usage, though it is not a requirement that PEV load be separately billed (each of the IOUs currently has a 'single meter' rate available to its PEV customers).

2.3 Single Metering

Under this arrangement, PEV usage is billed to the house meter. Both the home usage and PEV usage are billed at the same tariff rate.

Total Installation Hand-offs. Minimum of 4. This arrangement requires the fewest hand-offs and results in the fewest installation delays because it does not require changes to the meter. PG&E believes that single metering results in the simplest installation process.[42]

Cost. No additional meter is needed, though it may be necessary to equip the EVSE or vehicle with a communication device to receive load management and other smart grid messages.

Billing Flexibility. No billing flexibility – all PEV load must be billed at the same rate as the rest of the customer's load. This avoids the opportunity to shift usage between two meters to reduce cost ("load arbitrage").

Communication Functionality. Without additional communication devices in the EVSE or PEV, this meter arrangement does not provide any direct communication with the utility or the HAN network. Additional communication devices would need to be included in the EVSE or PEVs to allow vehicle charging to automatically respond to load management messages.

Other Issues. Under a single tariff for both home and EV usage, customers currently on tiered rates could find themselves paying very high rates for PEV charging if they do not switch to a TOU rate. PEV charging would lift their rates into upper tiers, resulting in a very high marginal rate (over $.35/kkWh) for their PEV charging.

Party Comments. SCE commented that whole house metering would meet user needs during the early market stage.[43] PG&E commented that this installation approach results in the simplest back office integration.[44]

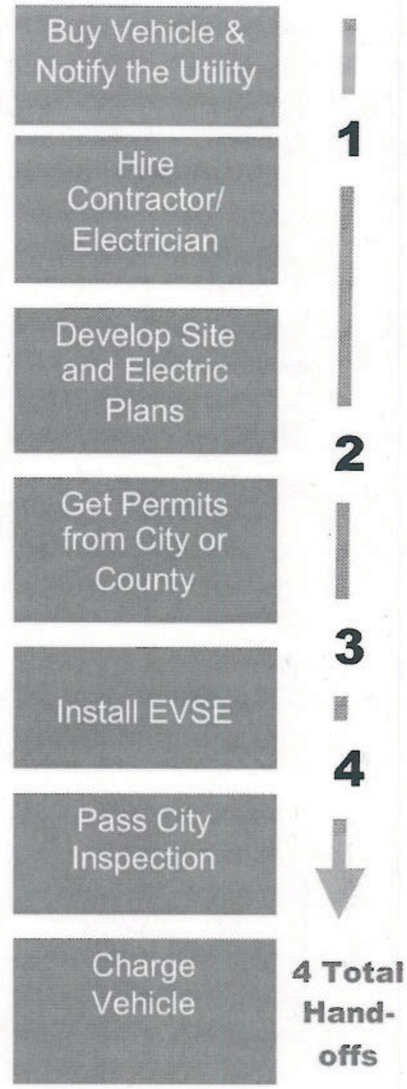

Figure 7. EVSE INSTALLATION STEPS for SINGLE TARIFF METER. **Assumes PEV load is served by AC Level 2 EVSE and metered as part of the total residential load. Assumes no panel upgrade or distribution system upgrades are needed.**

[42] PG&E presentation, March 16th Joint Agencies Workshop.
[43] SCE opening comments at p.11.
[44] PG&E presentation, March 16th Joint Agencies Workshop.

2.4 Separate Metering

The PEV is assigned its own revenue-grade meter, and PEV usage is measured and billed separately from the rest of the house usage. This meter will likely be served by a separate service line, connecting to the transformer, though dual meter adapters that use the same service line have been used in the past.

Total Installation Hand-offs. Minimum of Six. The utility will need to install and seal the meter once the contractor has completed the EVSE installation and other upgrades. According to PG&E, parallel metering results in the most complicated installation.

Cost. This meter arrangement requires a second meter and a dedicated panel for the EVSE.[45] The utility may need to upgrade the service line from the transformer to the customer to serve the new meter and panel.

Billing Flexibility. Maximum flexibility. Customer can use any tariff they want for their PEV, while still separately billing their home load. Separate billing also introduces the opportunity for billing arbitrage.

Communication Functionality. If the PEV meter is AMI compatible, the PEV would appear as an AMI node. As an AMI node, the meter could directly participate in utility demand response and load management programs. Additional communication functions may be needed to enable the customer to connect to the HAN network. Connecting with the HAN could allow customers to control charging, though the user could communicate directly to their vehicle or using a smart grid-enabled EVSE.

Party Comments. IREC commented that separate metering would increase the cost of EVSE equipment and would result in installation delays.[46] SMUD shared this concern regarding installation delays, stating that utilities are not equipped to handle a significant increase in meter installations and inspections. This would only be an added cost of submetering if utilities owned and installed the submeter.

Utility Role in PEV Charging

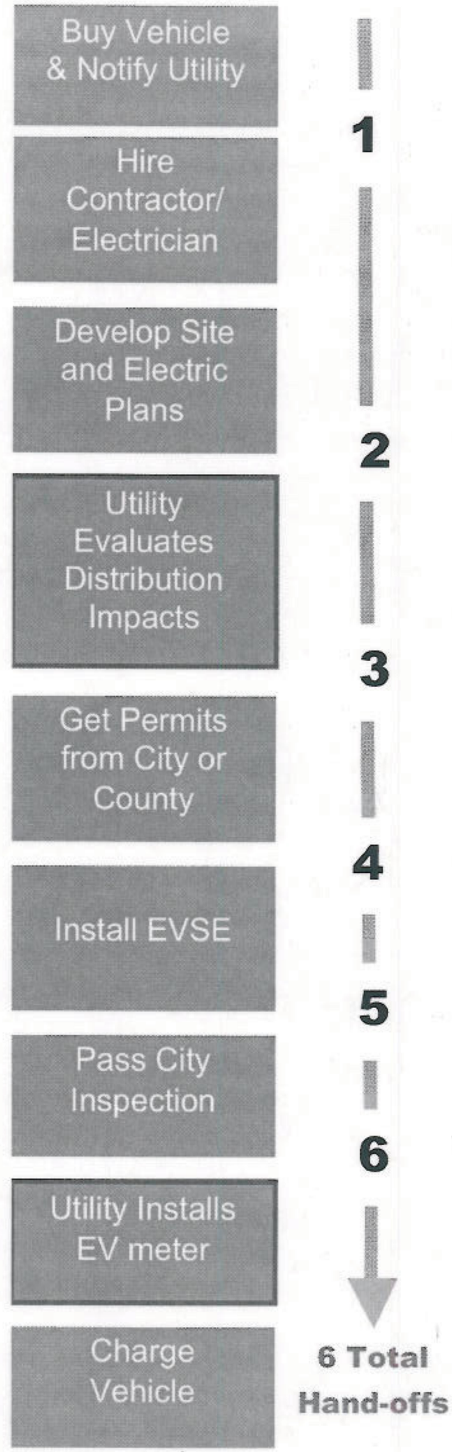

Figure 8. EVSE INSTALLATION STEPS with SEPARATE METERS. **Assumes PEV load is served by AC Level 2 EVSE and metered by a separate, utility-owned meter and does not account for panel or distribution upgrades.**

[45] It is possible that the EVSE could contain the panel and/or circuit breakers.

[46] IREC reply comments at p. 5.

2.5 Submetering

All usage is first measured through the primary meter, while the PEV usage is also measured by a dedicated submeter. The PEV usage can be subtracted from the primary meter to separately bill the house and PEV consumption. This "subtractive billing" is accomplished by back office billing software that links the meter data from the two meters and separately calculates the charges.

Total Installation Hand-offs. Minimum of five.

Cost. This meter arrangement requires a second to serve as the submeter. Additionally, this metering arrangement may require additional utility back office costs to integrate meter data into billing information.

Billing Flexibility. Maximum flexibility, but may require back office utility upgrades.

Communication Functionality. High functionality can be achieved with an AMI-compatible submeter, which would serve as a node on the AMI network and could also be a part of the HAN. Equivalent functionality can be achieved by installing these features in the vehicle or the EVSE.

Other Issues. The submeter could be owned by the utility, the customer, or an energy service provider (ESP). Section 4 discusses the impact of the customer/utility boundary.

Party Comments: Better Place commented that submetering was "an important step to ensuring that independent providers can participate in the market."[47] AeroVironment expressed concern that requiring submetering for customers during the early market phase would be costly and increase installation time.[48] PG&E expressed concerned that submetering could result in increased costs, especially to integrate data for bill calculation.[49] SMUD commented that the submeter would facilitate future metering options – such as including the meter in the EVSE – which may be beneficial to customers in the long run.[50]

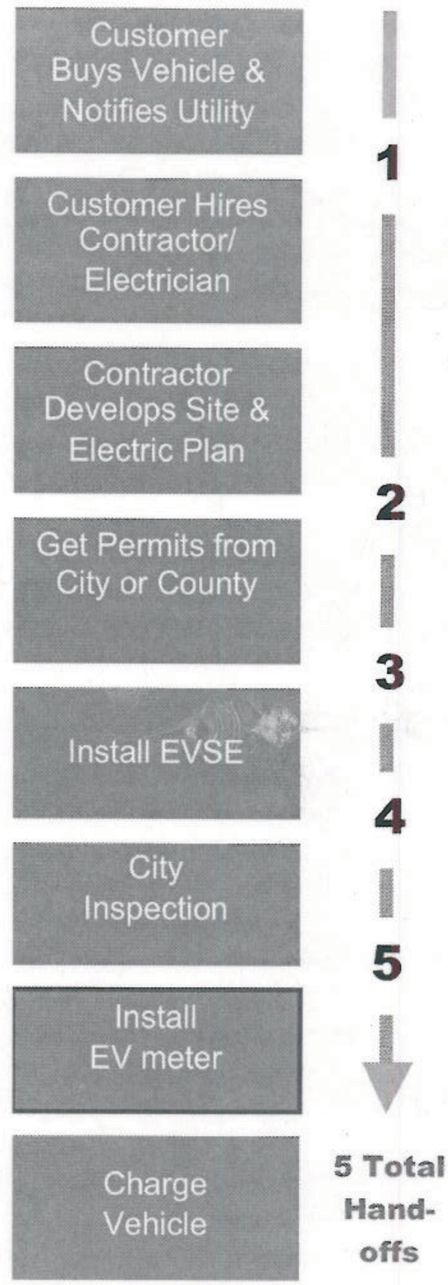

Figure 9. EVSE INSTALLATION STEPS for SERIES METERING. **Assumes all PEV load is served by AC Level 2 EVSE and metered by a PEV meter connected to primary meter on the customer side. Assumes no panel or distribution upgrades are needed.**

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[47] Better Place opening comments at p.6.
[48] AeroVironment opening comments at p. 4.
[49] PG&E reply comments at p.8.
[50] SMUD presentation, March 16th Joint Agencies EV Workshop.

2.6 Safety Issues

Separate metering can trigger safety issues, depending on the installation plan. Emergency responders need to be able to cut off electricity when they respond to fires and other emergencies. Separate metering can create a safety problem if the service line is located far from the main service or if it the service panel is not easily identifiable. Emergency responders would prefer to have a single circuit breaker location. Single metering and submetering do not require a second service line, eliminating this risk to emergency responders.[51] Separate metering can minimize this risk to emergency responders by co-locating the PEV and house panels. A less effective option would be to include maps or signage at the main panel that indicate the existence and location of the EVSE panel.

2.7 Installation Complexity Comparison

The table below compares installation "complexity" based on the estimated number of visits from contractors, utility representatives and inspectors for each metering option, both with and without a panel upgrade.

Table 1. Installation Visits for Each Proposed Metering Arrangement Scheme

	Without Panel Upgrade				With Panel Upgrade			
	Single House Meter	Separate Meter	Submeter (utility-owned meter)	Submeter (Customer -owned meter)	Single House Meter	Separate Meter	Submeter (utility-owned meter)	Submeter (Customer-owned meter)
Contractor Visits	2	2	2	2	2	2	2 or 3	2 or 3
City Permit Visits[52]	1 or 2	1 or 2	1 or 2	1 or 2	1 or 2	1 or 2	1 or 2	1 or 2
Utility Visits	0	2	2	1 or 2	2	2	2	2
Minimum Visits	**3-4**	**5-6**	**5-6**	**4-6**	**5-6**	**5-6**	**5-7**	**5-7**

2.8 Criteria Matrix

The following table compares each of the metering options based on the criteria listed in subsection 2.2. Submetering is broken into two categories to show the impact of customer-owned submeters versus utility-owned submeters. As PG&E stated in its March 16th workshop presentation, each of the three metering categories optimizes different criteria. Single metering optimizes installation time and cost, but provides no billing flexibility. Separate metering optimizes billing flexibility, but does not minimize costs or installation time. Submetering moderates the impact of some criteria (customer cost, and billing flexibility) relative to the other metering arrangements, but results in additional back office costs for the utility.

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[51] Verbal communication from Kevin Reinertson, California Office of the State Fire Marshall on August 26, 2010.

[52] This counts the trip an electrician makes to the county permit office to get permits as a 'city permit visit.' In some municipalities, electricians can electronically file for permits.

Table 2. Criteria Matrix for Proposed Metering Arrangement Options

Criteria	Single Metering	Separate Metering	Submetering (Customer Owned)	Submetering (Utility Owned)
Minimum Installation 'Hand-offs'	4	5	5	6
Additional Costs (beyond EVSE installation costs)	Minimal, assuming no panel upgrade required	Separate meter + meter installation + dual meter adapter + panel cost	Submeter	Separate AMI meter + meter installation + dual meter adaptor.
Communication Functions	Requires additional communication devices in the EVSE or PEV	Full functionality of AMI meter	Varies depending on meter type. May require additional communication functions in EVSE or PEV	Full functionality of AMI meter
Billing Flexibility	None. Must be billed the same as the home usage	Full Flexibility	Uncertain	Full Flexibility
Other Issues	Need a submeter for LCFS credit tracking.	Introduces electricity rate arbitrage opportunity	Introduces electricity rate arbitrage opportunity	Introduces electricity rate arbitrage opportunity

2.9 Additional Issues for Residential CSI Customers

Parties did not raise any unique metering issues for customers with existing or considering the option of installing solar PV panels and use a PEV. Any of the three metering options discussed could be utilized by CSI customers who own PEVs. Additional analysis will be necessary to determine if there are tariff or other limitations / requirements that suggest a preferential (or prohibitive) metering arrangement for customers who combine the use of solar panels and PEVs.

2.10 Metering Requirements for LCFS

ARB has yet to determine specific metering requirements for measuring LCFS credits, so the metering requirements for LCFS credits could be lower than those for utility revenue grade meters. As discussed in Section 1.5, most CPUC incentive programs set lower technical meter requirements for metering incentive activity as a means of reducing costs for participants. The use of lower cost meters would likely reduce the accuracy of electricity measurements, increasing inaccuracy from 1-5%.

Presumably, the separate and submetering options can be aligned with the LCFS credit program once ARB sets specific requirements; however, the single metering option does not appear to be compatible with the LCFS credit program, since the PEV load is not isolated. In this case, some form of secondary metering will be required to conform with the LCFS credit program.

ARB may want to consider allowing LCFS meters to be located in vehicles. ARB has the authority to set requirements for vehicles that qualify in its ZEV program, and could require that all ZEV vehicles include a meter that meets LCFS specifications. This requirement may increase vehicle costs, but may decrease overall costs for customers under single metering, by reducing their need to purchase an additional meter solely for LCFS credits. ARB and other state agencies would need to determine how this meter would communicate PEV electricity usage to the utility. Additional communication functions would be needed to assign credits between PEV electricity provided by the utility and third party EVSPs.

Section 3: PEV Metering for Other Customer Types

Although the majority of PEV charging is expected to take place at single family residences, PEV charging will need to be made available in other residential and non-residential settings. This section explores metering issues for the following customer types, locations and arrangements: multiple dwelling units, workplace charging, third party public charging, and future metering possibilities.[53]

Charging in other locations will often involve an intermediary between the actual PEV owner and the utility. The metering arrangements described in this section refer to the utility metering arrangement with the account holder. This metering arrangement does not necessarily reflect the billing and meter arrangement experienced by the PEV owner.

3.1 Multiple-Dwelling Units (MDUs)

In the majority of MDUs, tenants in individual units are metered directly by the utility. Decision 05-05-026 determined that the building owner is required to separately bill each tenant using a utility-owned revenue grade meter in all buildings built after 1982.[54]

For the MDUs that are individually metered by utility, all three metering options appear to be feasible. Whole house metering (in this case, billing all the PEV and household load for each tenant under one rate and meter) would appear to be the easiest to implement. Separate metering could face space constraints, which might in turn increase total installation time and cost, as all the building's meters are grouped in one area. Submetering might also generate space constraints, though it might allow for more flexibility in meter location than separate metering would.

Table 3. PEV Metering in Utility-metered MDUs (w/o third party EVSPs)

	Single Meter	Submeter	Separate Meter
Description	Each tenant's overall usage is billed directly to her/his individual meter.	Each tenant's PEV usage is tracked by a submeter and subtracted from their primary meter	Each tenant has a separate meter for PEV usage.
Issues	How are LCFS credits tracked? Does the building owner or tenant receive LCFS credits?	Is there space to add a submeter behind the customer's utility meter?	Is there space to add a separate meter / service line next to the existing service (need to be co-located for first responder safety.

[53] According to PG&E's presentation at the March 16th Joint Agencies EV Workshop, the same general metering arrangements used for residential customers also apply to other customer types.

[54] CPUC Decision 05-05-026 found that landlords could administer submetering through their own meters.

Submetered MDUs with third party EVSPs. An MDU owner may choose to allow a third party EVSP to provide charging services to its tenants. Under this situation, the building owner and the EVSP would need to develop a system for recovering costs. If the EVSP is operating under the building owner's account, the EVSP would need to compensate the building owner for the electricity used, or provide a system for allowing the PEV user to directly pay the building owner for this usage. A building owner would also theoretically have the option of not billing tenants for this usage.

PEV Metering in pre-1982 Apartments (Master-metered MDUs). Owners of MDUs (or mobile/manufactured homes) built during or prior to 1982 can choose to allow the utility to individually meter tenants or use one primary utility meter for the entire building ('master metering'). In the master metered arrangement, the building owner can either embed the cost of electricity into the rent charged or bill each unit separately for their usage with submeters that are owned, maintained, and monitored by the building owner. CPUC Decision 05-05-026 allows building owners to purchase CEC-approved submeters to use in determining the electricity costs of each of their tenants. The building owner is ultimately responsible for paying the utility for the entire facility amount of electricity on the property's master meter. For these accounts, the electricity rates are adjusted to account for the building owner's cost in purchasing and managing the submeters. In 2004, the Commission estimated that less than 40,000 MDUs are currently master-metered.[55]

If a third party EVSP owned and operated EVSE in a master metered MDU, the EVSP would have two choices for getting its electricity: through the owner's master meter or through a separate service. There are no MDU-specific complexities associated with the scenario in which the EVSP obtains its electricity through a separate service. However, if the EVSP received its electricity through the building owner's account, and the EVSP could require that tenants pay for usage directly for their usage directly at the charging station. However, Electric Rule 22 may bar the use of an EVSP in an MDU if the EVSP is determined to be an ESP, per Tariff Rule 22.

[55] CPUC Decision 05-05-026.

Table 4. PEV Metering in Master-metered MDUs

	Single Meter	Submeter	Separate Meter
Description	Tenant usage is billed directly to building owners account.	Tenant PEV usage is tracked by a submeter.	Tenant has a separate meter for PEV usage.
Issues	Building Owner pays the entire bill and passes cost onto tenants How are LCFS credits tracked? Can the building owner or tenant get them?	Building owners of master-metered MDUs are already allowed to submeter their tenants. Building owners can only recoup their cost if they do this, they cannot profit. Is there space to attach a submeter to the customer utility meter?	Building owner sets up a separate account to separately meter PEV usage. Requires new panel and new meter. Separate meter and service line needs to be next to existing service to avoid problems with first responder issues.

Other Metering-Related Issues for MDUs. Determining who pays the costs related to EVSE installation further complicates the installation process. Building owners would benefit from owning the EVSE if it helps attract tenants, but they risk not finding tenants that will compensate them for the EVSE expense. Tenants may be reluctant to buy the EVSE if it is burdensome or costly to remove and reinstall it when they move. Additionally, it is unclear who should be responsible if the PEV installation triggers a panel upgrade. While the building owner would normally be responsible for these costs, it is not clear that they would be willing to bear this cost if only specific customers created and benefited from them.

3.2 Workplace metering issues

The key factors impacting metering arrangements for workplace charging appear to be the need to track LCFS credits and the ability to bill PEV owners directly for their workplace consumption.

LCFS credits. Tracking LCFS credits for workplace charging would require at a minimum some form of monthly kWh load total for commercial facility charging.

User Charges. Workplace charging can facilitate PEV adoption, but also could create special challenges for load management. In its presentation at the March 16th workshop, Clipper Creek explained how PEV users in a pilot test conducted at Georgia Power would charge at work rather than at home, despite the fact that they each had EVSE installed at their homes. Presumably, these customers realized the cost advantage of charging at work, where they did not pay for electricity.[56] The availability of subsidized workplace

[56] Clipper Creek presentation. March 16th Joint Agencies EV Workshop.

charging could encourage daytime charging, reducing the load benefits of nighttime charging at home.

User payment for workplace charging can reduce the incentive to charge during the day. Price signals are ineffective at influencing charging behavior if the user does not experience them. Alternatively, submeters could be billed directly to a customer credit card or billed directly to their home account. Submeters would need to be AMI compatible to communicate billing messages with the utility and the primary meter. However, as in the case of residential charging, submetering may require significant back office costs for utilities.

Table 5.PEV Metering Arrangements for Workplace Charging

	Single Metering	Separate Metering	Submeter
Without Third Party Providers	Simple installation Low cost Difficult to track LCFS credits Need a way for employees to measure usage and reimburse employer	Complex installation High cost Easy to track LCFS credits Need a way for employees to reimburse employer	Medium installation Moderate cost Easy to track LCFS credits Need a way for employees to reimburse employer.
Issues with Third Party Providers	Requires a way for third party charger to measure usage and reimburse employer for electricity cost	Allows third party provider to set up its own utility electricity account. Easy for employer to measure third party provider usage. May need method for third party provider to reimburse employer.	Allows third party providers to provide submeter integrated with the EVSE Need method to reimburse host for electricity cost.
Ideal Applications	Using charging as an employee benefit/incentive	Best for coordinating with third party provider.	Supports flexible billing (between third party, employer and employees) and allows flexible charging arrangements

While businesses would have to pay the cost for EVSE and metering equipment and any electricity they provide, it is not clear that this expense is enough to incent these businesses to bill their workers or customers. It may be possible for workplaces and commercial entities to allow a third party to establish its own electricity account with the utility, thereby eliminating a need for a workplace or commercial entity to collect revenue from the user or the third party EVSP.

3.3 Metering for Third Party EVSP Public Charging Stations

The billing issues in public charging are the same as workplace charging, in terms of metering arrangement options and their respective advantages. Public charging will also raises the same issues in regard to direct billing and LCFS credits.

3.4 Future Metering Possibilities

As SCE pointed out in their opening comments, the technology used in PEVs is rapidly developing, but current technologies limit metering arrangements.[57] Several parties asked the Commission to provide sufficient flexibility to accommodate the various possible directions that the market may move over time. Three possible metering technology changes could impact the Commission's policies: meters embedded in the EVSE, meters incorporated into vehicles, and AMI changes that allow submetering within one meter.

Meter embedded in the EVSE. In the future, EVSE manufacturers could include a meter inside the charging station equipment. Including the meter in the charging equipment would simplify the installation process for submetering, by eliminating the need for a separate installation of the meter. A meter in the EVSE would need to meet utility requirements for communication, data storage, and accuracy. This approach would raise utility-customer boundary issues, which are addressed in Section 4.

Meter Incorporated in the Vehicle. Manufacturers of PEVs are not currently including meters in their vehicles. However, the complex battery charging data tracked by the vehicle's onboard computer is able to provide metering functions at minimal additional cost, which are addressed in Section 4. A meter in the vehicle raises similar utility boundary and specification issues as a meter in the EVSE. A meter in the vehicle may also add complexity to LCFS credit assignment. ARB is currently considering assigning LCFS to the entity that provides the charging service – either the utility or the third party charge provider. For LCFS purposes, a vehicle meter would need to track charge location in addition to total kWhs.

Future AMI Developments. AMI meter technology is expected to evolve as meter communication technology improves and communication protocols are defined. In the future, existing AMI meters may be able to track a subload by communicating with a second meter. If a meter has a communication channel dedicated to communicating with a PEV submeter, existing AMI meters could accommodate separate billing. It is unclear if this functionality will require hardware changes in addition to software changes.

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[57] SCE opening comments at p.11.

Section 4: Utility Role in PEV Charging

All parties agreed that utilities will play an important role in PEV adoption. Based on party comments, this section examines the utility role in five areas: the utility-customer service boundary, EVSE cost, EVSE installation, LCFS credits, and vehicle roaming. Some issues related to the utility role will not be addressed in this paper. In addition, issues related to ratemaking and direct charging management will be addressed in future white papers.

4.1 Utility "Boundary" Background

In general, the Commission has defined the utility-customer boundary relative to what is called the "service point." The service point is the point on a customer's property where the utility delivers electricity via a service wire from the transformer. Customers are responsible for the installation and maintenance of wiring used to deliver electricity from the service point to other parts of their property. An important exception to this rule is the fact that the meter is usually located on the "customer side" of the service point, despite the fact that the meter is usually owned and maintained by the utility. In some cases, the service point is located on the second story, where a meter could not be easily accessed by the utility. The wiring used between the service point and the meter is owned and maintained by the customer. Figure 11 illustrates how the utility-customer ownership boundary is defined for most customers. [58]

It is important to note that the ownership determination does not always determine what entity is responsible for paying for the purchase, installation or maintenance of infrastructure or equipment. In some cases, customers are responsible for paying for upgrades to infrastructure that will ultimately be owned by the utility.

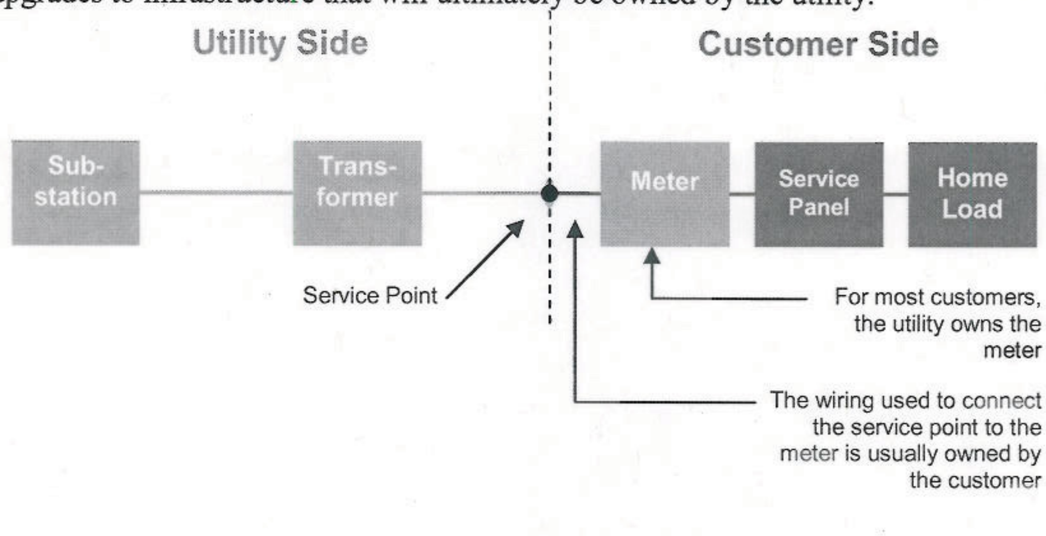

Figure 10. Utility-Customer Infrastructure Boundary.

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[58] Electric rules can be found on each of the utilities websites: PG&E (http://www.pge.com/tariffs/ER.SHTML#ER), SCE (http://www.sce.com/AboutSCE/Regulatory/tariffbooks/rules.htm), and SDG&E (http://www.sdge.com/regulatory/elec_rules.shtml).

Meter Ownership. Generally, the utility owns the meter that is used by customers to measure their billable load. However, there are cases where the utility does not own the submeter that is used for billing purposes:

- 'Grandfathered' apartments that use submetering furnished by the apartment owner to bill customers off of a utility-owned master meter;[59]
- Mobile home parks or manufactured housing developments where the developer is allowed to use submeters and bill customers the utility rate;[60]
- RV parks where the park owner does not absorb the energy cost through rent, but instead uses a submeter to calculate the direct electricity costs for each tenant;[61]
- Multi-tenant commercial buildings where the owner is allowed to submeter tenants with customer-owned meters;[62]
- Marina or harbor operators that opt to submeter individual berths or slips with customer-owned meters;[63] and
- Direct Access customers or their energy provider may opt to own their own meter.[64]

The Commission sets the performance requirements for meters owned by Direct Access customers (see Section 1.5).

In the case of net energy metering, the customer is permitted to own the meter that is used for subtractive metering under a multiple tariff account. Net generation metering customers that have multiple generators receiving different rate treatment are eligible to own their own net generation output meter.[65] The utility must read these meters to determine the generation amounts that are attributable to different generators in order to accurately calculate the total net meter compensation.[66] The utility retains ownership of the primary meter, which measures the aggregate load from which the PEV usage is subtracted. Standby charges and other tariff requirements may also require the use of meters that may be owned by customers.

Rules for Capacity Upgrades to Existing Service. Changes in customer electricity usage (home additions, new appliances, etc.) can necessitate upgrades to customer panels, meters, service lines or other components of the utility's distribution system. Customers requiring service upgrades usually cover the cost of these upgrades, though cost allowances are granted by the utility, if additional load supports the cost.[67] The cost assignment of these upgrades does not change the ownership of these components. For customer owned infrastructure that requires upgrades, the customer must hire a contractor and is responsible for these costs. Any changes made to utility-owned meters must be

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[59] PG&E Tariff Rule 18C-1, SCE Tariff Rule 18, SDG&E Tariff Rule 19.
[60] Ibid.
[61] Ibid.
[62] PG&E Tariff Rule 18C-2, SCE Tariff Rule 18, SDG&E Tariff Rule 19.
[63] Ibid.
[64] PG&E Tariff Rule 22, SCE Tariff Rule 22, and SDG&E Tariff Rule 25.
[65] Non-emitting generation receives a net metering amount, while some emitting distributive generation is refunded at the wholesale rate
[66] PG&E Tariff Rule 22-F (3), SCE website (http://www.sce.com/customergeneration/net-energy-faqs), and SDG&E website (http://www.sdge.com/nem/interconnectionRequirements.shtml).
[67] See PG&E Tariff Rule 15, SCE Tariff Rule 15, and SDG&E Tariff Rule 15.

done by the utility and the utility is responsible for "re-sealing" the meter after modifications are complete.

In some cases, changes to a utility's infrastructure may necessitate changes to a customer's service. In cases where service modifications are driven by utility convenience, the utility bears the cost of these modifications.[68] Although these modifications may impact customer-owned infrastructure (such as panels), they do not impact the utility-customer boundary.

Current Boundary Issues for PEVs. Under existing utility tariffs, the utility owns the meter used by PEV owners who separately meter their PEV load. In the PEV context, several key questions emerge related to the utility-customer boundary. The boundary issue appears to be a foundational PEV policy issue, as it impacts the EVSE installation process, utility cost assignment, and utility rate policies.

4.2 PEV Boundary Issues in Single Family Residences

Section 2 discussed three types of metering arrangements available to residential customers – single metering, submetering, and separate metering. The ownership boundary issue is important to each of these metering arrangements to determine who will bear the cost of what infrastructure.

Single Meter Arrangement. Under a single meter arrangement, no additional panels or meters are added to the customer side of the meter, though a panel upgrade may be necessary. The customer boundary is not changed with regard to the panel or the meter.

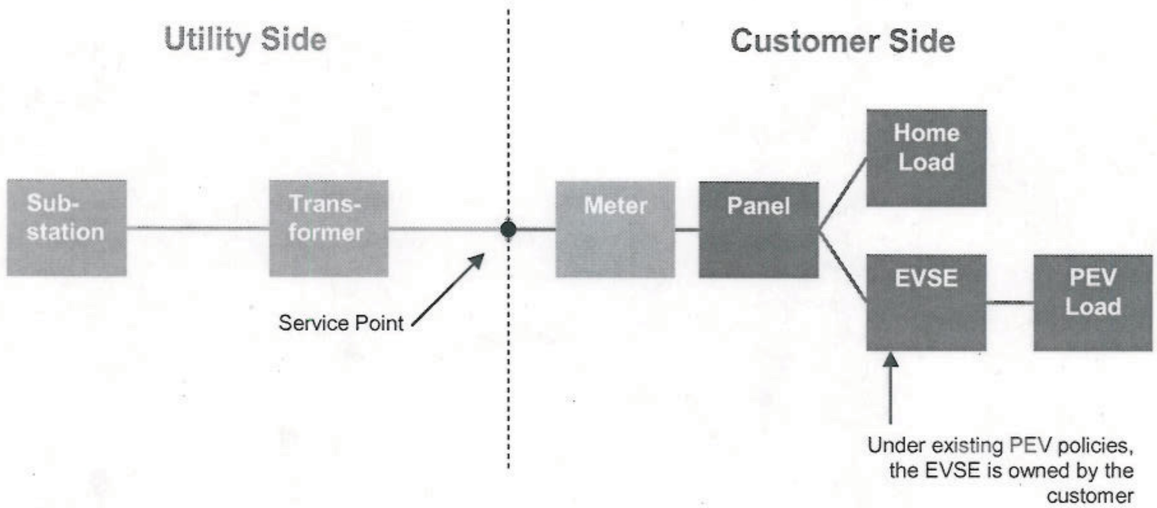

Figure 11. Utility-Customer Boundary under a Single Meter Arrangement.

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[68] Ibid.

Submetering Under submetering, a separate meter is connected downstream of the primary meter to allow for separate billing of PEV load. Under this meter arrangement, the utility-customer boundary will need to be determined in regard to the second meter. The meter is on the customer side of the primary meter and would appear to be customer-owned equipment. However, the utility usually assumes ownership of the meter unless an exception is made in the utility tariff rules.

Better Place indicated third parties should be able to own submeters used for PEVs, and that these meters should be allowed to connect to a third party data management system and not be required to communicate through utility smart grid networks. PG&E agreed that third party ownership of submeters should be considered by the Commission, but that the costs and other impacts should be evaluated by the Commission in making this decision.[69] PG&E contends that if submeters are allowed to be owned by third parties, utilities will require detailed specifications regarding meter performance and integration with utility smart grid networks.[70]

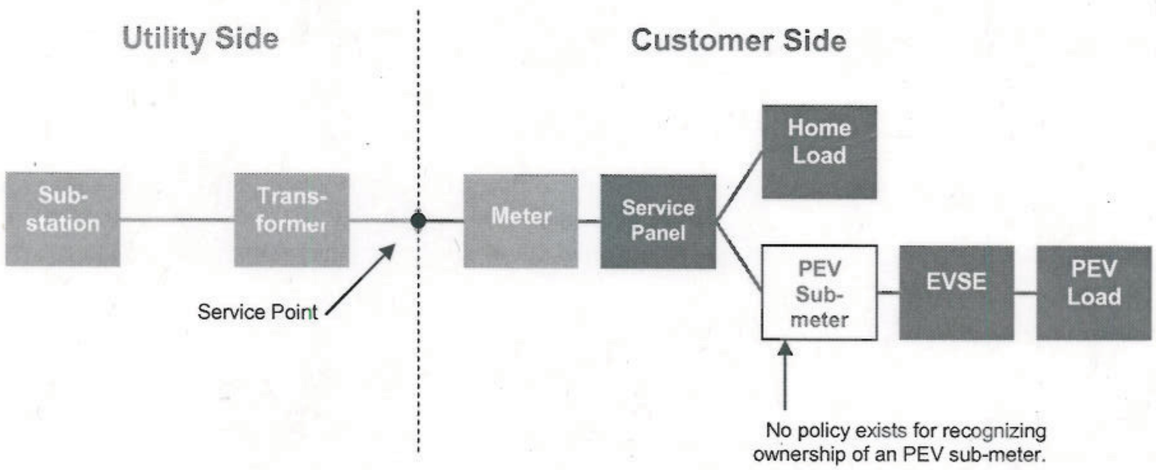

Figure 12. Utility-Customer Boundary under a Submetering Arrangement.

Customer ownership of PEV submeters provides the following advantages:

- Allows customers to respond to changes in technology over time. Allowing customers to own a PEV submeter used for billing may allow the market to develop new metering approaches that provide customers with cost or functional advantages. KEMA identified a similar benefit to allowing customer-owned meters to connect to the AMI network.[71]
- Allows customers to benefit from a competitive market that could reduce total metering costs for customers.

Customer ownership of PEV submeters also raises the following issues:

- If meters are not owned by the utility, the utility's role in calibrating and inspecting them will need to be clarified.[72] Security requirements would also need to be

[69] PG&E reply comments at p. 8.
[70] Ibid.
[71] KEMA, 2009.
[72] SMUD presentation, March 16th Joint Agencies EV Workshop.

developed to prevent tampering with meter data or introducing new opportunities for cyber attacks against the utility network.

- Utility ownership of submeters may introduce economies of scale that reduce customer costs for submeters. Customer-owned submeters may be more costly that utility-owned submeters if a competitive market for submeters does not reduce costs compared to the purchase power of the utilities.

Separate Metering. Under separate metering, a separate meter is connected upstream of the primary meter to separately measure the PEV usage. This meter will likely be served by a separate service line, connecting to the transformer, though dual meter adapters have been used in the past. As a separately metered load, the PEV load will be treated like a separate utility account, though this account can be aggregated on a single customer bill. Some current PEV customers use separate metering for PEV load. In these cases, the meter is owned by the utility, consistent with utility tariff rules.

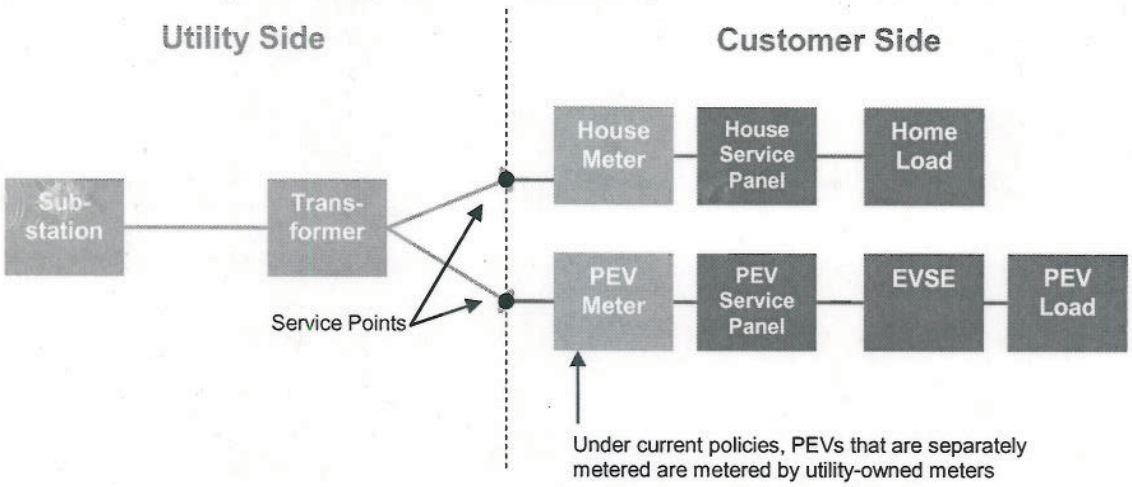

Figure 13.Utility Customer Boundary under a Dual Meter Arrangement.

Customer ownership of the meter under separate metering provides the same benefits as customer ownership of submeters, but introduces similar to those risks (load manipulation, tampering, etc.) for DA customers that have a customer-owned meter.

4.3 Boundary Issues in Other Customer categories

MDUs, workplace charging and public charging face similar boundary issues as single family residences. In each of these charging situations, single metering and separate metering follow well-established boundary rules, while submetering introduces the issue of meter ownership. For workplace charging and public charging stations, rules governing ownership of the submeter may impact their approach to PEV metering, as discussed in Section 3. In master metered complexes, the owners have the authority to submeter their tenants, which would seem to also apply to PEV usage.

4.4 Other Boundary Issues

The technology advances identified in Section 3.5 could raise new metering issues in the future.

Meters in the EVSE. Meters in the EVSE would raise new boundary issues between the utility and the customers for series billing. If the customer is required to use a utility meter for billing, then the EVSE (or, at least, the meter within it) would need to be owned by the utility in order to serve as a submeter in a series metering arrangement. This would represent a significant change in the customer-utility boundary, as the EVSE is currently regarded as customer-owned equipment on the customer side of the meter. However, a vehicle in the EVSE would not necessarily need to be owned by the utility – such a meter could be treated the same as a customer-owned submeter.

Meters in the Vehicle. Vehicle meters used for billing would raise the same boundary issues as EVSE meters. Requiring utility-owned meters in the vehicle would likely form a significant barrier to vehicle-based meters, as vehicle manufacturers would have to meet vehicle meters with the requirements of hundreds of US utilities. Similar to above, a meter in the vehicle would not necessarily need to be owned by the utility.

4.5 Utility Role in EVSE Deployment

Party comments suggested that the utility role in relationship to EVSE raised two issues: utility ownership of EVSE and utility subsidization of EVSE material and installation costs.

Utility Ownership of EVSE. Under existing PEV policies, the EVSE is not owned by the utility because it is located on the customer-side of the meter. Utility ownership of the EVSE would represent a significant change in the existing customer-utility boundary. While utility subsidization of the meter could impact PEV adoption and infrastructure development, it is not clear that utility ownership of the EVSE is also needed to achieve this effect.

Cost subsidization. GM estimates that customers are willing to pay $500-1000 for EVSE purchase and installation - significantly below the current cost estimates for EVSE purchase and installation at a single family residence.[73] Currently, state and federal subsidies are available for customers that install EVSE equipment. A federal subsidy provides a tax credit equal to 50% of the cost of the EVSE, with a maximum of $2,000 available per household.[74] The city of Los Angeles is proposing a $2,000 tax credit to the first 5,000 EVSE installations in the city.[75]

In their opening comments, some parties suggested that the EVSE could be included in the utility ratebase. Utility involvement in EVSE installation and purchase may reduce the cost – Clipper Creek believes this was the case in the Georgia Southern pilot project, which reduced installation and material costs through bulk purchases.[76]

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[73] GM presentation. March 16th Joint Agencies EV Workshop.

[74] California Energy Commission, 2010. 2010-2011 Investment Plan for the Alternative and Renewable Fuel and Vehicle Technology Program.

[75] LADWP presentation, March 16th Join Agencies EV Workshop.

[76] Clipper Creek presentation, March 16th Joint Agencies EV Workshop.

It is unclear what business models for EVSE distribution will be supported by the market. Some automakers may distribute EVSE with their vehicles or customers may buy their own EVSE at retail stores.[77] 'Ratebasing' of EVSE by the utilities could create an "unlevel playing field" on which independent EVSE providers would need to compete.

Beside ratebasing, additional options for financing EVSE could be made available. The City and County of San Francisco suggested that local governments or utilities could finance infrastructure through taxes or utility bills, respectively.[78]

4.6 Utility Role in EVSE Installation

Utilities expressed a need for a notification system that would alert them when a customer purchased a PEV. PG&E states that purchase notification is an important aspect of the utilities role in the installation process.[79] Upfront data on who purchases a PEV is important to start distribution impact analyses and avoid customer service interrupts or future EVSE installation delays. While customers are required to notify the utility whenever they increase their load, however this requirement does not define what constitutes a load increase. Electricians generally define a load increase as anything requires a change to the service panel.[80] If utilities received notice whenever there was a panel upgrade, they would only be receiving notice during the installation process and would not receive notice about the PEV installations that do not regard a panel upgrade. Even if a PEVE installation does not require a panel upgrade, it may still trigger upstream distribution upgrades for the transformer.

Voluntary notification is necessary to avoid privacy issues.[81] Currently, there is no communication program between utilities and customers or car dealers, but utilities are currently exploring agreements with auto manufacturers to establish a system that would provide utilities with notice when a customer in their service territory purchases a PEV.

4.7 Utility Role in LCFS Credits

Most parties agreed that the use of LCFS credits given to investor-owned utilities should be determined by the CPUC. Parties' proposals for the use of this revenue are summarized below.

- *Return value to PEV customers.* DRA, PG&E and SCE all suggested that the Commission return the value to PEV customers.[82] GM made a similar argument, suggesting that this value could be used to reduce costs for customer EVSE and to provide incentives to customers who purchase PEVs.[83] If LCFS value were returned to customers on a per unit basis, staff argues that customers would have a greater incentive to use their PEVs. However, staff also thinks this subsidy could also reduce

[77] GM Presentation at the March 16th Joint Agencies EV Workshop.
[78] City of San Francisco presentation, March 16th Joint Agencies EV Workshop.
[79] PG&E presentation, March 16th Joint Agencies EV Workshop.
[80] Verbal communication with Enid Joffe, CEO of Clean Fuel Connections, on Aug. 26, 2010.
[81] SG&E presentation, March 16th Joint Agencies EV Workshop.
[82] DRA opening comments at p.18, PG&E opening comments at p.30, and SCE opening comments at p. 49.
[83] GM opening comments at p. 23.

price signals during peak hours, which could increase the incentive to charge during peak hours.

- *Return the value to all ratepayers.* PG&E suggested LCFS value should be returned to all customers.[84] PG&E argued that PEV electricity demand could increase electricity costs for all electricity customers. LCFS value could be returned to all customers to offset this cost increase. Under this approach, LCFS credits would not serve as an incentive to the PEV users who generate the credits. SCE, the Environmental Coalition and Coulumb suggested that LCFS value be used for infrastructure investments.[85] SCE, SDG&E, SMUD and the Environmental Coalition suggested that the Commission use LCFS value to reduce the cost of AB 32 mitigation efforts and RPS costs.[86]

4.8 Utility Role in 'Vehicle Roaming'

Some parties commented that utilities should facilitate charging in other territories by providing a billing system that would allow billing to be made directly to a PEV owners account when they travel to other territories.

While this would encourage PEV use and could simplify the user experience when charging away from home, the costs of developing and operating such a system appear to be significant. Utilities would have to develop a 'clearinghouse' that would allow them to exchange information about charging costs to one another and 'true-up' revenue. It is not clear that these costs are justified. The ability to travel long distances will primarily be a factor of the availability of charge stations and less a function of the payment method. Charge stations can easily be equipped with payment methods at the service point, eliminating the need for a costly data/revenue exchange between utilities.

Without a 'roaming' program, LCFS credits generated from sales of electricity would accrue to the third party EVSP or utility that provides the vehicle electricity, rather than the customer or their home utility. More compelling justifications for a 'roaming and true up' billing system could emerge if non-residential charging proves to be a widespread practice and is subject to unfair pricing practices, or if new metering arrangements that facilitate roaming (such as vehicle-based metering) become commonplace.

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[84] PG&E opening comments at p. 30.

[85] SCE opening comments at p. 49, the Environmental Coalition opening comments at p.53, Coulumb opening comments at p. 13.

[86] SCE opening comments at p.49, SDG&E opening comments at p. 33, SMUD comments at p. 16, Environmental Coalition opening comments at p.53.

Section 5 Conclusions, Recommendations and Questions

This section summarizes the conclusions drawn from party comments on the OIR and the information and analysis provided in this paper. Based on these conclusions, staff proposes several policy recommendations regarding PEV metering arrangements and other related policy issues. The paper concludes with several questions staff has identified for further stakeholder input.

5.1 Conclusions

- Metering is a critical policy issue for PEV adoption. Three main themes emerge from the comments received in response to the OIR: the Commission should allow flexibility in metering arrangements available to customers, various options exist for the functionality that should be included in PEV metering requirements, and some form of segregation of PEV load that is deemed adequate by ARB is needed to measure LCFS credits.
- A dedicated meter for a PEV is not necessary to enable communication functionality needed to participate in load management, demand response, or 'smart charging' programs. PEV meters may not need "smart" capabilities if communication functions are included in the EVSE or PEV.
- Metering arrangements will impact total installation cost, installation time, and billing flexibility.
- 'Single metering' results in minimal installation hand-offs, likely reducing the total installation time for customers, and minimize installation costs, but would still likely require a submeter to measure PEV load for LCFS credits and may require smart communication functions embedded in the PEV or the EVSE in order to enable automatic load management control.
- Billing flexibility, where the customer can choose independent rates for their PEV and house usage, can only be achieved under a submeter or separate meter arrangement.
- Different metering arrangements may be attractive to different customer types. Each of the metering arrangements offers different attributes which may be attractive to different customers and customer types. While residential customers may be attracted to single metering for its simplicity and low cost, commercial and workplace chargers might be attracted to separate metering for its billing flexibility.
- Submetering requires that the Commission determine who should own the second (PEV) meter. Meters are usually owned by the utility, though there are examples of the utility using customer owned meters for billing purposes.
- Allowing utility billing from non-utility owned meters would allow flexibility to adopt to future market conditions, including meters located in EVSE or the vehicle itself. This flexibility could reduce costs for consumers and all the market to respond to changing technologies and business models within the PEV and EVSE industry, but may necessitate additional utility back office changes and costs.
- Although LCFS metering requirements have not been recommended by ARB, minimal functionality might be able to meet their requirements.

- Under current IOU rules, the submeter and the EVSE both fall on the customer-side of the meter and would be owned by the customer.

5.2 Proposed Recommendations

Based on its analysis on metering issues to date, staff proposes the following recommendations related to metering arrangements and the utility role in vehicle charging.

Near-term Recommendations (12-36 months)

Until all PEV metering and data requirements are better understood, utilities should encourage single family residential customers to use a single meter arrangement for PEVs to avoid stranded costs. This arrangement minimizes installation delays, avoids possible safety issues, and is adaptable to new metering technologies and metering business models that may emerge for vehicle charging in the future. Each utility should continue to facilitate the use of separate or submeter PEV configurations by customers.

Utilities should establish an installation notification protocol to help understand and prepare for local distribution impacts. These protocols should establish a system that informs the utility of when a customer purchases a PEV without violating personal privacy issues.

Long-term Recommendations (36+ months)

The utilities should propose tariffs that support all three meter arrangements. The three primary meter arrangements should be available to customers, and utilities should design tariff and billing systems to support each type. Given the nascent stage of the PEV market, the Commission should allow as much choice and flexibility as possible.

The CPUC and utilities should establish minimum metering requirements for each of the three potential metering options.

Table 6. Recommended Minimum Meter Functionality for Each Proposed Metering Arrangement

	Single Metering[87]	Submetering	Separate Metering
PEV Metering Accuracy and Functionality	N/A	Greater accuracy of the submeter is achieved at a higher cost to customers.	Require the same accuracy requirements as AMI meters. Require AMI compatibility[88]
Minimum load data granularity	N/A	Multiple time intervals consistent with the number of intervals in the utility PEV tariff structure	Multiple time intervals consistent with the number of intervals in the utility PEV tariff structure
Minimum Communication Functionality for the meter	N/A	Daily reporting will be necessary to enable consumers to track online billing information.[89]	Same as AMI primary meter
Minimum Meter Data Storage Functionality	N/A	TOU data storage	Same as AMI meter
Boundary Definition	EVSE should be owned by customers	PEV meter and EVSE should be owned by customer	PEV meter should be owned by utility, EVSE should be owned by the customer
Who owns for the meter?	Utility owns primary meter used to measure all usage	Customer	Utility

The CPUC and utilities should actively monitor PEV and metering technology to identify new metering options or challenges in the future. Commission metering requirements should avoid proscribing alternative metrologies that may emerge as the market matures.

ARB should evaluate the use of on-vehicle usage tracking to meet LCFS credit tracking and consider other alternative metering configurations. Through its ZEV program, ARB has the ability to establish requirements for vehicles meeting the ZEV requirements. ARB should evaluate the cost and effectiveness of tracking LCFS credits through on-board metering devices. If other load management and communication requirements can be accomplished with other devices than a second meter, this may

[87] In order to receive LCFS credit beginning in 2015, customers that use Single Metering may need to incorporate a secondary meter to track the PEV usage. Flexible accuracy requirements (1-5% accuracy) for this secondary meter could allow customers to reduce the purchase cost of this meter.
[88] HAN communication functionality should be an optional component left to the discretion of the EVSE owner.
[89] Communication with the HAN could also serve this function.

ultimately be the least costly approach to tracking PEV-eligible LCFS credits (i.e., rather than installing a second meter solely for LCFS purposes).

5.3 Questions for Parties

Parties should address the following questions in comments on this paper.

- Are there additional meter arrangements that the utilities should consider beyond those identified in this paper?
- Do some metering arrangements better encourage (or discourage) future technology changes or market developments relative to other arrangements?
- What factors should the Commission consider in determining the utility-customer boundary in regards to submeters and EVSE?
- What utility role issues should be prioritized by the Commission in order to facilitate PEV adoption beginning in Winter 2010?
- What back office communication functions are necessary to allow utilities to process submeter data?
- What metering arrangements should be used for residential homes with PV panels?
- How does the issue of roaming impact metering requirements?

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(END OF ATTACHMENT A)

Energy Division Staff Workshop Report
California Public Utilities Commission
Workshop on the Utility Role to Support Plug-in Electric Vehicles
September 27, 2010

Introduction

On September 27, 2010, the California Public Utilities Commission (Commission) held a public workshop on the utility role in plug-in electric vehicle (PEV) charging as part of the Commission's Alternative-fueled Vehicle Rulemaking (R.09-08-009). This workshop provided parties an opportunity to discuss the issues addressed in a Commission Staff Issues Paper, "The Utility Role in Supporting Plug-In Electric Vehicle Charging," issued August 30, 2010. The workshop was divided into four panels covering the following topics: residential metering requirements, workplace and multiple dwelling unit metering requirements, utility notification of electric vehicle charging equipment (EVSE) installation and EVSE ownership and subsidization.

This Energy Division Staff Workshop Report summarizes issues and party positions considered at the workshop. Energy Division staff notes were used to develop this summary. These notes are based strictly on the verbal commentary provided during the workshop and do not refer to party written comments. The Report is being provided to the proceeding service list and will be subsequently entered into the record toward the end of 2010 (October 27, 2010 Administrative Law Judge Ruling at p. 7).

1. Residential PEV Metering Requirements

Panelists:

Christine Cullen, Pacific Gas and Electric (PG&E)
Gregg Morris, Green Power Institute (GPI)
Sven Thesen, Better Place

Party Positions:

Parties agreed that all three metering options proposed in the Commission Staff Issues Paper should be made available to PEV owners. In the short-term, parties felt that whole house metering should not be encouraged by the utility. While submetering presented promising opportunities for the future, it would require detailed protocols in order to determine what specifications the submeter should be required to meet. Parties were divided over the future viability of onboard vehicle meters.

Meter Choice. Although single metering does not allow for separate billing of the PEV load, Commission staff thought that the single metering arrangement could still achieve all of the functionalities presently needed for PEV users by relying on communication functionality embedded in the vehicle and the charger. Demand response (DR) functionality needs can be accomplished through the EVSE of the vehicle capable of communicating with the DR aggregator or utility. Measuring usage for LCFS credits or excise taxes could be accomplished by simple, inexpensive meters in the EVSE or the vehicle. ARB has yet to determine what data requirements will be necessary to get LCFS credits, nor is it understood what data will be necessary for calculating excise taxes. If the data requirements for these metering methods are relatively simple, then using inexpensive meters to accomplish these tasks would be cheaper than using revenue-grade meters for each PEV. Single metering would simplify the installation process and allow time to determine what technology options develop in the mid-term, while reducing infrastructure investments for early adopters. The staff paper recommendation was to encourage, but not require, single metering.

While parties favored providing customers with a choice over their meter arrangement, most disagreed with the Commission Staff recommendation that utilities encourage customers to use single metering over other options in the short term to prevent stranded costs as the market evolves. Parties were concerned that single metering would not discourage on-peak PEV charging, though some parties also acknowledged that customer behavior would be influenced by the tariff used. Better Place felt that the utilities should further explore how single metering would work for PEV users. Green Power was concerned that single metering might limit the benefits the grid can obtain from PEV, though single metering may be beneficial for ramping up the market. NRDC wondered whether the single meter approach was really the lowest cost option, given the functions that would need to be added to allow it to provide all the data collection functions needed. Given the sub metering process may take time to resolve, NRDC asked how the Commission can ensure the single metering option includes a process to integrate the desirable functions down the road.

Rather than encourage single metering, Better Place thought that the Commission should evaluate single metering since it may push some households into unfavorable billing conditions. Better Place also thought that direct metering of electric vehicles provided information important to understanding more about driver's charging behavior. Additionally, Better Place thought that a second meter would be needed to verify DR participation.

Submetering. While parties agreed that a submetering option should be made available to PEV customers, most thought there were many issues that needed to be addressed before this would be a viable option.

Better Place argued that submetering was important for EVSPs acting as an intermediary between the utility and the customer. Putting a submeter in the EVSE may be cheaper than other metering options and can include "smart" communication technology. Better Place hopes to provide charging services for residential customers, including single family homes.

The majority of parties thought that PEV submeters should be owned by the customer or a third party. Better Place thought that this would enable vehicle/home owner access to and control over the data. Better Place expects that meters in the EVSP would be owned by owner operator or electric vehicle service providers (EVSPs) and would communicate directly to utility via HAN system.

SCE urged the Commission to explore submetering by first articulating its vision and goals. If the purpose is to encourage participation in particular utility rates, then the Commission should understand that today's metering options are available to do that. SCE disagrees that imbedded submetering is the only solution. There are other ways to achieve the stated objectives without getting involved in the complexities of imbedded submetering.

Parties agreed that a protocol was necessary to set meter performance requirements and other rules regarding utility access to the meters. Parties identified the following issues that could be addressed through the development of a submetering protocol:

- *Equipment standardization.* PG&E thought that standardization of the equipment for submetering will improve the utilities' ability to utilize these technologies. There is an existing standard that PG&E applies to all its meters and it uses national standards for meter certification. When direct access metering was approved, parties developed a standard for these meters. Parties will need to work with manufacturers to establish standards because this is a new technology.
- *Meter certification.* Better Place thought that EVSPs would prefer to not certify individual meters within IOU territories. Instead, Better Place preferred a statewide common standard for the technical requirements of the submeter. Coulomb thought that submetering requires some certification process, and that process should be lightweight, rapid, and inexpensive.
- *Meter calibration.* SMUD asked how submetering calibration would be addressed. Better Place thought that this was a standards issue and should be included in a Commission timeline for addressing submeter standards.
- *Timeline.* Parties thought there was a need for a timeline to address all of these issues.

SCE identified some resources that would be valuable to consider in conjunction with submetering issues. Under Direct Access, third party owns the submeter that is utilized for billing necessitates the accuracy of the meter. The March 1999 Commission document "Direct Access Standards of Metering and Meter Data" sets the metering standard for direct access customers where the utility does not own the data but uses the data for billing customers. SCE thinks this can serve as a template for the submetering process, as it is a statewide standard developed at the Commission that is not utility specific. SCE thought that the submeter standards would need to address consumer protection, LCFS credits, and road taxes.

GPI thought that onboard vehicle meters are, in effect, sub meters. Standardized technical protocols are very important and enable the mobility of these submeters.

Parties were not concerned about the potential for rate arbitrage when using a submeter at a residence. PG&E did not know of any specific instances of this occurring, but thought that there needed to be protections against attaching additional load to the PEV meter. SCE thought that the current system operates like an 'honor system' -- there is no existing mechanism for stopping load shifting between meters. There may be the potential to develop auto identification systems that would trigger the use of the PEV meter.

TURN asked if Better Place was contemplating having their customers pay for utility side upgrades required to deal with non-utility owned submeters. Better Place thought that it would be appropriate to develop a cost share agreement based on an analysis of costs and benefits of the upgrades related to submeter integration. In the near-term, Better Place might be interested in a "non-proprietary work-around" to avoid the utilities network, since there is current no cost treatment or standards for interfacing with utility AMI networks.

PG&E expressed concern that the submetering issues might be outside of the realm of the Commission's authority if it were only used by EVSPs for their own billing purposes. The Commission has no role over the third parties in terms of their services to the customers. If this is the case, PG&E was unsure what agency would have a role in providing oversight over submetering. TURN also asked who would regulate submeters, including settling customer disputes.

Onboard vehicle metering. Green Power Institute advocated for onboard vehicle meters as a mid-term metering option that could address the numerous data needs associated with electric vehicles. GPI thought that collecting information/data on the vehicle over its lifetime would be very useful for all parties. A smart charging mechanism could perhaps transmit information to the utility and could utilize this communication to modulate the grid supply in response to the vehicle's charging needs. Green Power Institute affirmed that this is not a near term solution, but that there is significant potential to utilize on vehicle metering to benefit the grid, utility and the vehicle owner. For example, with a 'smart' onboard vehicle meter, you could theoretically communicate to different utilities for your billing; i.e. if you charge outside of your service territory, the other power company could communicate with your smart charger and pass information related to your charge onto your home power company for billing purposes.

Better Place did not think that onboard vehicle metering was realistic because car manufacturers and owners themselves do not have a vested interest in collecting this information, in addition to the technical difficulties associated with onboard vehicle meters. Onboard vehicle meters also raise new issues, such as billing when a vehicle leaves home.

EV Connect thought metering could take place in the vehicle, comparing vehicle technologies to the recent rapid change in cell phone technology. EV Connect also thought the single meter solution is the best metering approach, and that it doesn't foreclose the ability to utilize the other metering options. Making metering as simple as possible should be a goal of the Commission's proceeding.

Smart Grid communication with the meter. Green Power Institute though smart charging may require more than one vehicle tariff: one for 'unsmart' charging and another lower rate for charging that integrates with a 'smart device' and can communicate with the grid.

GPI felt that vehicle charging will typically be off peak as vehicles are primarily used in the daytime and charged at night, particularly with TOU rates. There is a potential benefit to allowing some daytime charging as long as it is 'smart' charging that is controllable by utilities.

PG&E thought that the existing smart metering may have the capability to separate each appliance's use in the future, and that a single meter may someday have the option of identifying specific PEV load.

PG&E thought that third party ownership of meters would require that these devices be HAN-enabled. If the devices aren't ready to integrate with the utilities AMI network, then it could result in additional costs.

GPI asked utilities how additional services imbedded within the AMI device get turned on. PG&E said that IOU AMI systems provides 'home area network enablement' but those devices do not currently contemplate IOU-compatible submetering. The HAN is currently viewed as a communication mechanism for monitoring use patterns, not for billing. As home area network devices come into the marketplace, these devices might be upgraded able to provide billing information, but this is unclear because of limited marketplace availability. GPI hoped that national standards would be developed for submetering capabilities.

Other Metering Issues. Dual meter adapters could be an additional option for facilitating separate metering. Dual adapters reduce customer cost, according to PG&E, but are not currently Underwriters Laboratories (UL) compliant. Without a UL listing and with limited deployment in the field, PG&E did not think these devices are not a near-term option.

Audience members asked about the potential impact on transformers from PEV charging. PG&E does not expect transformer overloading to be an immediate concern but could become an issue as market penetration increases.

Staff Observations:
Parties generally agreed that consumer choice is important, submetering has a lot of unanswered questions that need to be resolved through protocol development, and single meter should not be encouraged over other metering arrangements. Parties also thought that the Phase 2 Decision could begin the submeter protocol development.

2. Multi-Dwelling Units (MDUs) and Workplace Metering Requirements

Panelists:
Colleen Quinn, Coulomb Technologies
Jose Salazar, SCE
Jim Brady, EV Connect

Party Positions:
Parties agreed that MDU metering presented technical and billing challenges. Typically, MDUs are metered using a bank of meters, while individual service panels are located within the dwelling unit. Adding a PEV branch circuit breaker and running the line to the parking lot generally involves complicated and costly infrastructure modifications.

Parties did not think that EVSE and meter installation at MDUs introduced new safety issues. Historically meters have been very safe and parties did not see a safety issue specific to the PEV meters in MDUs. These installations may be improved by UL approval of certain equipment, such as dual meter adapters. Anytime a utility customer is doing a service add request, it is routed through utilities so there is the opportunity for oversight.

SCE suggested the use of submeters off a dedicated feeder or circuit that feeds bulk charging for all the vehicles in a given facility, whether at an MDU or a workplace. This could avoid the need for panel upgrades each time a vehicle is added at an MDU. It would be the option of the homeowner / MDU owner to decide to take advantage of the rates; the owner would distribute charging costs and would develop an infrastructure to support that decision. The utility may have to monitor electricity of PEVs due to LCFS and other user specific information.

Commission staff asked SCE about the difference between bulk charging and master metering. SCE thought that bulk charging offered additional options to MDU owners. Due to the complexity of the unit, the location of where a customer is charging is likely not their specific meter. When you add an EVSP as the billable customer in a bulk charging situation, this would be a separate customer who would be billed separately and treated as an independent customer. Coulomb thought their technology could facilitate such a transaction by enabling the host to individually bill their customers.

Coulomb Technologies thought that the Commission should endorse imbedded metering to address the challenges of MDU charging. Imbedded meters allow a separation of the consumer from the ratepayer. The cost of imbedded meters is cheaper than other sub metering technologies. Imbedded meters can also be smart meters – demand response, remote service enabling and disabling can all be components of a charging station that includes an embedded meter. Coulomb provides a 'flex billing' option for the host. The owner of the vehicle charges with a swipe card and that enables the host to distinguish particular users. Identifying the vehicle user and allowing the host to apportion different costs to different users is the premise of their business model and is being applied by MDU owners. Coulomb's technology enables the host to develop their own specific business model for recovering their costs. Creating this flexibility might require changes to the customer-utility boundary. Imbedded metering facilitates flex payment plans as a service. This need for flexibility also applied to the commercial sector and fleet management. Fleet managers may want to utilize the imbedded meters for data tracking.

Regarding commercial properties that already have workplace charging, TURN asked the utilities how often the transformer will need to be changed if the property installs additional charging stations in the future. SCE thought that this issue would be specific to individual facilities. One generalization is that commercial facilities already have large electricity load capacity available to them; in the case of commercial facilities, there is less likelihood of overloading than in residential applications. This also depends on the voltage of charging station installed.

TURN was concerned that offering workplace charging would encourage on-peak charging. Other parties did not think this was an issue -- if commercials facilities use 6-8 kW chargers, most PEV users will be done charging before noon, hence there is not expected to be significant peak charge. In regards to 'when' charging occurs at commercial establishments, SCE thought it might present an opportunity to integrate with renewables. Coulomb also mentioned that usage data from Coulomb stations installed as part of a CEC grant would provide helpful data to understanding the charge impact of non-residential charging.

Regarding billing at commercial sites, SCE thought this issue would be captured if all commercial entities were on time-of-use rates, which would help dissuade employers from allowing peak time charging. SCE also thought that drivers would need to pay for vehicle charging in order for them to respond to this signal. EV Connect shared some of these concerns and thought that workplace charging might need to be a pay service in order for this to work.

Interstate Renewable Energy Council (IREC) asked how the Commission can encourage the use of distributed renewable energy to charge PEVs at the residential and commercial level. IREC wanted to Commission to consider virtual or aggregate net metering to facilitate customers linking their renewable energy production to PEV charging. This is an issue in the case of master metering MDU's. IREC also wanted to know what the Commission is doing now to make net metering an option for PEV owners.

Commission staff asked if utilities were considering how to assign a particular rate to DC charging. SCE did not consider DC charging to be different from other charging voltage levels. With AC charging, the charger is on board vs. DC charging where the charger is remote. DC charging at band 3 is 'fast charging' and is 200 kW, really intended to buses, etc and will need further attention from the utility. EV Connect thought there were many challenges to these installations and that standards should be developed before fast charging stations are installed at customer sites.

Staff Observations:
Parties thought that MDUs present unique PEV metering and EVSE installation challenges. While parties thought that all three metering arrangement options discussed in the staff Issues Paper were possible for MDUs, it was unclear which option would best facilitate rapid installation and flexible billing options. Determining the feasibility and effectiveness of new techniques, such as the bulk charging approach discussed by SCE, requires additional research.

3. Utility Notification

Panelists:

Dan Bowermaster, PG&E
Ed Kjaer, SCE
Alex Keros, General Motors
Eileen Tutt, California Electric Transportation Coalition (CalETC)

Party Positions:
Parties agreed that the notification issue did not fall directly within the Commission's jurisdiction, but encouraged the Commission to continue facilitating a dialog between parties, in the hopes of reaching a mutually-acceptable solution. Parties also felt that utilities would be best served by a notification approach that could draw data from multiple sources.

CalETC stated that there were three pieces of information for notification: coverage (number of vehicles sold in CA), specificity (for chargers of 240 volts and higher, utilities need to know vehicle address, since zip code info will not protect against outages) and time (date when the vehicle is sold). This information can come from three possible entities: OEMs (who will have purchaser addresses), local governments (who have addresses when the permit for chargers is issued), and the DMV.

General Motors thought that a system needed to be developed that would relay system information to utilities while respecting customer privacy. Automakers do not want to impact customers or impact the local grid. GM expects to have third party installers work with the customer on the installation. The first step in GM's installation process is to get a customer survey that will allow customers to opt into information sharing with the utility. GM can provide PEV purchase information (address and vehicle type) to utilities for the customers that allow this information to be shared. Then GM discusses the utility installation process and options with the customer. GM says that their overall goal is to reduce market barriers without adversely impacting grid. However the notification issue is addressed, it will result in an administrative cost for some entity or entities. GM believes that most people will opt to notify the utility if given the opportunity, but research is needed to confirm. Results of the initial deployment of this process (during the next 8 – 16 months) will drive how to implement this process.

GM now has its own privacy statement, which basically reads: "GM will not show your personal information with any third parties unless we get your explicit consent." The California's Driver's Privacy Protection Act, protects driver's DMV information but allows 11 exceptions to the rule about gaining information. Utility lawyers will have to analyze whether utilities can pull information from DMV on driver records. GM's survey does not have customer name in their database for security and privacy issues.

SCE presented a 'purchase funnel' graphic to describe what opportunities exist for getting utility notification of PEV purchases. Lowest granularity is zip code, which is not enough for utility system planning. The next level is zip + 4, which is better, but many people do not know the last 4 digits of their zip. The next more granular level is after purchase, when utilities get address information provided by automakers. This could also happen when customer asks the OEM or the utility for a home inspection to determine if their home is PEV-ready. Customer may decide to upgrade to 240V some time after purchasing car – if so, the utility needs this info from a system reliability perspective.

GM did not know what the administrative costs of operating a 'data clearinghouse' would be, but that these costs would be highly dependent on scalability. A uniform national system would be necessary to reduce costs.

When asked about short-term solutions in the absence of a national system, PG&E thought that utilities needed to know the total number of customers during the early stages. SCE thought that the OEMs and utilities needed to agree on a process that both could live with, while utilities also needed a means of collecting information from the DMV to track vehicle re-sales.

While parties did not identify a specific role that the Commission should play in facilitating utility notification, SCE thought that the current informal stakeholder process is working and there is a need to keep stakeholders working together, especially in early years of this nascent industry.

EV Communities Alliance was concerned about the lack of local government participation in these conversations and was worried this was a sign that local government agencies do not have time to address PEV issues.

PG&E wanted to know what needs to be done for *near-term* readiness on market roll-out and long-term rationalization and institutionalizing these changes. PG&E asked what the Commission and the utilities can do to address gaps on permitting and panel upgrades and OEM notification. SCE said that California Energy Commission (CEC), California Air Resources Board (CARB), and Commission need to continue working together. On outreach and education, CEC can help with the cities, CARB can help with automakers-side, and the Commission can help with other agencies, including cities and local inspectors. SCE thought that getting cities ready was critical.

The Commission asked if it would be appropriate to penalize customer for not notifying the utility when customers introduce new load. GM thought that that was too heavy handed and that it might create a market barrier.

Better Place wanted EVSPs to be included in the notification process. Information about customer should be used for grid planning and reliability, not marketing. EV Connect thought that data gathering has to be at building permitting process and that it is EVSE installer's responsibility.

Commission staff asked if there is a need for legislation to encourage secondary customer (i.e. re-sale transaction has occurred) to notify utilities or a third-party clearinghouse about changes in PEV ownership. SCE said that not all re-sale goes through a dealer, only 1/3 goes through a dealer franchise. That data will need to be procured from DMV registration data after the fact. GM did not think there is a need to get info from DMV, but thought that this information could come from third party installers or EVSPs. There are multiple pathways to get information on secondary customers. Commission staff also mentioned that local permitting agencies were another option.

Staff Observations:
In general, parties thought that there is a need to develop a system of managing notification data, but that it wasn't clear that the Commission had a clear role in developing the system. Such a system would likely cover several data sources, including OEMs, DMVs and local governments. While there is a long-term need for a national system of notification, parties thought that California will need to play a leading role in advancing such a system.

4. EVSE Ownership & Subsidy

Panelists:

Alex Kim, SDG&E
Nina Suetake, TURN
Bill Barbanica, Leviton

Party Positions:

Many parties agreed that there was not a clear need for utilities to own EVSE, however some parties asked the Commission not to rule out utility EVSE ownership at this point, as the marketplace may fail to provide charging services for all situations.

Regarding the "utility boundary" issue, SDG&E thought the Commission needs to make sure it does not limit the market at this early stage. Regulation needs to be customer-centric. The Commission, according to SDG&E, should provide the least amount of barriers and provide for utility participation in the market. Additionally, SDG&E said that there is precedence for the utilities to own devices behind the meter.

TURN was concerned that the focus on reducing regulatory barriers would place burdens on ratepayers. Various parties mentioned subsidies and rate basing, but a PEV is still a consumer product that a customer is choosing to buy. In Direct Access, meters are owned by customers, and TURN does not see why that shouldn't be the case if a meter is within an EVSE. While it may be appropriate for EVSEs to be supported by federal/state incentives, it is completely different to allocate these costs to a body of ratepayers.

Commission staff asked if parties were concerned about a potential unfair competitive advantage to utilities if utilities owned EVSE. SDG&E did not think utilities would have a competitive advantage over non-utility EVSPs. There is value in utilities being in the market because, from SDG&E's perspective, utilities can help open up the market during the early years. Customers should have the option to choose which model to go with, whether utility charging or other commercial entity. TURN thought that utilities could have a huge competitive advantage over other market participants, to an extent that utilities can rate-base EVSE equipment. Leviton thought that not all customers want the utility to know when and how they are charging their cars. A "big brother" perception could affect customer acceptance.

Commission staff asked about the allocation of distribution costs as it relates to the boundary issue. TURN thought that any customer-specific distribution cost should be born by the customers. CEERT asked TURN how to allocate costs that are associated with non-conventional benefit categories. TURN thought that social benefits should be addressed through taxes, not electricity policies. TURN also recognized that there is sometimes a 'gray zone' in which environmental benefits in some cases do need to be recognized through rate treatment.

Clean Energy asked if TURN opposed a utility forming an independent affiliate to participate in the EVSE market. Though unsure of all the legal requirements of an unregulated subsidiary, TURN would have less of a problem with utilities owning EVSE if these activities were shareholder-financed.

Commission staff asked if utility ownership of EVSE could play a role in serving areas where there is market failure. Coulomb was evaluating car-sharing arrangements for low-income customers to utilize PEVs, acknowledging that there is an issue of affordability for these customers. SDG&E thought the analogy of the pay phone might be appropriate for low-income and under-served areas. With this approach, the utility could install charging stations in areas not served by other entities. SDG&E and also thought that the Commission should figure out what the market needs are before it determines whether an IOU should or should not participate in the

EVSE market. SCE agreed with SDG&E's point that IOUs could serve as a back-stop entity to provide services other participants do not provide.

DRA thought that the issue of ownership should be separated from subsidization. It is entirely possible that the IOU could own the EVSE, but pass the full cost on to PEV owners as a monthly charge in the bill. In this case, the IOU could own the equipment and be responsible for its operations and maintenance, but the EVSE cost would not be borne by all ratepayers. Precedents include past TOU pricing programs where the TOU meters are charged to TOU customers. NRDC agreed with DRA, stating that cross-subsidization is indeed different from ownership issue. The Commission does not need to decide the IOU ownership issue in the near-term. DRA reminded parties that in the telecommunication sector, the utilities originally owned the telephone. When this changed, telephone innovations increased rapidly, according to DRA.

Commission staff asked if there was still too much uncertainty to rule out utility ownership of EVSE. Clean Energy Fuel thought that the overall goal is to encourage a competitive market. To the extent that other companies want to enter this market, utility participation with ratepayer backing would certainly distort the market. However, leaving the utility role undefined provides regulatory uncertainty for non-regulated entities.

PG&E stated that the thought the utility ownership issue should be addressed from the perspective of what public policy goals the Commission decides it wants IOUs to achieve in the PEV market. Once the Commission determines a charging market structure, the appropriate IOU role will be clearer. The Commission, according to PG&E, creates more regulatory uncertainty by trying to draw a line that nobody can agree upon. Instead, PG&E thought parties should first decide whether IOUs have an obligation to serve in the EVSE space.

Staff Observations:
Many parties thought that the Commission should maintain the status quo of not allowing utilities to own EVSE. IOUs suggested that it was too early to predict how the market will play out and that the Commission should not rule out future utility ownership of EVSE.

(END OF THE UTILITY ROLE TO SUPPORT PLUG-IN ELECTRIC VEHICLES WORKSHOP - SEPTEMBER 27, 2010)

Revenue Allocation and Rate Design

FACILITATING PLUG-IN ELECTRIC VEHICLE INTEGRATION

INTRODUCTION

The widespread use of plug-in electric vehicles (PEV) is a significant opportunity to reduce greenhouse gas (GHG) emissions in support of California's GHG emission reduction goals, and an opportunity to reduce petroleum consumption in California. Senate Bill 626 (Kehoe, Chapter 355, Statutes of 2009) requires the Commission to evaluate policies to overcome any barriers to the widespread deployment and use of plug-in hybrid and electric vehicles.

Background

In August 2009, the California Public Utilities Commission (PUC) opened the Alternative-fueled vehicle (AFV) Rulemaking (R.) 09-08-009 to ensure that California's investor-owned electric utilities (IOUs) are prepared for the projected statewide market growth of light-duty passenger plug-in hybrid electric vehicles and battery electric vehicles.[1] More recently, the assigned Administrative law Judge's (ALJ), August 9, 2010 Ruling set forth the scope of issues and schedule for Phase 2 of the proceeding. The ruling sets a schedule for four workshops to address Phase 2 issues: Utility Role, Revenue Allocation, Rate Design, and Smart Grid issues that overlap with those in this proceeding. Revenue Allocation and Rate Design are collectively referred to herein as "Rates" workshops.

In this paper Energy Division addresses the topics of Revenue Allocation and Rate Design. As stated in the ruling, the purpose of this paper is to review the existing record on these topics, provide preliminary analysis, and develop discussion questions to focus party comments in advance of the Rates workshops, which will in turn assist Energy Division in structuring the focus of the workshops themselves. Parties are requested to file comments to the specific questions explored in this paper within 13 days (e.g., by September 23, 2010) with the Commission's Docket Office. Comments should also be provided to all names on the service list for R.09-08-009 via electronic mail. This paper will not discuss costs or rates as they pertain to natural gas.

Rate design is a critical issue of this proceeding. Time-of-use (TOU) pricing signals may be designed to encourage PEV drivers to charge when economic and environmental impacts are lowest (e.g., during off-peak hours) to avoid adverse grid impacts and capacity addition requirements due to on-peak PEV charging. Pricing signals should reflect the cost of potential transmission and distribution (T&D) capital upgrades that may be required to support coincident, clustered PEV charging and should also account for supply side-benefits, such as improved dispatch of off-peak (fossil and wind) generation resources, and other asset utilization benefits. A critical issue is how the Commission intends regulated utilities to recover costs associated with dedicated distribution facilities and customer service expenses as cost components in rates. Additionally, there is the issue of societal benefits expected from the GHG emissions shift from oil and gas fuels to electric fuels, causing both a total reduction in GHG emissions, but also a shift in emissions from the transportation sector to the electricity (and gas) sectors. This is the subject of the Low Carbon Fuel Standard (LCFS)[2] electricity fuel credits.

Senate Bill 626

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[1] Order Instituting Rulemaking (OIR) on the Commission's Own Motion to Consider Alternative-Fueled Vehicle Tariffs, Infrastructure and Policies to Support California's Greenhouse Gas Emissions Reduction Goal (Rulemaking 09-08-009).

[2] http://www.energy.ca.gov/low_carbon_fuel_standard/

California Public Utilities Code § 740.3 requires the Commission "to evaluate and implement policies to promote the development of equipment and infrastructure needed to facilitate the use of electric power and natural gas to fuel low-emission vehicles. The Commission is required to ensure that the costs and expenses of any authorized programs are not passed through to electric or gas ratepayers unless the commission finds and determines that those programs are in the ratepayers' interest."[3]

Pub. Util. Code § 740.2 (as amended by Senate Bill 626, Kehoe, 2009) requires the Commission to adopt, by July 1, 2011, rules to address impacts on electrical infrastructure, including necessary upgrades and the role and development of public charging infrastructure, impacts of plug-in vehicles on grid stability and integration of renewable energy resources, and the impact of widespread use of plug-in vehicles (PEV) on achieving California's climate goals, which includes possibly shifting emission reduction responsibilities from the transportation to the utilities sector. The scoping memo issued in R.09-08-009 on January 12, 2010 indicated that the requirement in Pub. Util. Code § 740.2(f), regarding achieving the state's climate goals, may best be taken up in other proceedings or forums.

Scope of the Revenue Allocation and Rate Design Paper

This paper addresses issues for parties around revenue allocation and rate design, as it pertains to PUC Section 740.2 (a) and (b):

> (a) The impacts upon electrical infrastructure, including infrastructure upgrades necessary for widespread use of plug-in hybrid and electric vehicles and the role and development of public charging infrastructure.
> (b) The impact of plug-in hybrid and electric vehicles on grid stability and the integration of renewable energy resources.

Specifically, this issue paper will explore the following: If PEVs have "the potential to increase total energy consumption, substantially increase daily load capacity requirements, alter peak load shapes, increase transmission and distribution system demands, and result in net negative emissions of carbon dioxide (CO2), while increasing the electricity sector's emission profile",[4] what measures should be taken in order to allocate and recover necessary infrastructure costs, efficiently and equitably, and what rate design principles shall be employed in order to shift load, lower emissions, ensure grid stability and promote adoption?

The approach to addressing revenue allocation and rate design issues in the context of a 'new load' is dependent upon the type of application filed by the affected utility. A typical approach might follow a 3-step path:

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[3] http://www.leginfo.ca.gov/cgi-bin/waisgate?WAISdocID=3568795470+0+0+0&WAISaction=retrieve

[4] CPUC PPD white paper: "Light-duty vehicle electrification in California: Potential Opportunities and Barriers," 2009. http://www.cpuc.ca.gov/NR/rdonlyres/AD8A4A5E-6ED9-4493-BDB6-326AB86A028E/0/CPUCPPDElectricVehicleWhitePaper2.pdf

1. Determine the nature and extent of the new costs and benefits resulting from this new load, based on existing tariff electric rules, and determine which of these costs should be borne by the individual and which should be paid by all (or an appropriate subset or "class" of) customers;
2. Determine the revenue requirement associated with identified new costs and the appropriate revenue allocation; and
3. Develop a rate structure and, if appropriate, true-up mechanism that appropriately recovers the additional costs from individuals and/or all (or the appropriate class of) customers.

Evaluating these issues is a complicated, iterative process, particularly in the context of this new, not well-understood load. For example, consider the complexities in recovering the costs, net of benefits, associated with new PEV load through the rates being charged to several different classes of customers. At low PEV penetration, the calculation of net costs will be driven primarily by the distribution system upgrades that are needed to safely and reliably integrate into the grid the new PEV charging load. The distribution upgrade costs, though, will be dramatically different depending on charging behavior and charging voltage. However, it is expected that charging behavior, in turn, will be strongly influenced by the rates assigned to PEV charging. It may be, therefore, that a particular rate that is established for the initial market may influence behavior (or may not) such that the Commission may need to revisit PEV rate schedules as load profiles evolve.

This paper explores these broad issues and how they play out in the context of PEV charging by considering the following questions[5]:

- What types of time-variant rates should be offered to PEV owners?
- What characteristics should PEV rate designs have?
- How should residential PEV rates be designed given the inverted-tier (e.g. rising prices from Tier 1 to Tier 5) rate structure? And should the utility offer whole-house time-variant rates for electric vehicle owners, rates that only apply to electric vehicles, or both?
- What types of rates should apply to stand-alone commercial and public PEV charging?
- What types of rates should apply when a "customer" offers charging services?
- Should utilities be permitted to make expenditures in residential, commercial and public charging infrastructure? If so, how should a utility recover expenditures on charging infrastructure?
- How should a utility recover costs of distribution system upgrades attributable to electric vehicles? Should utility costs be recovered directly from the users of the infrastructure or from the wider body of ratepayers?
- Should utilities seek recovery of expenditures related to PEVs through general rate cases or are special applications necessary and appropriate?

This paper also provides some general ratemaking background to help parties better understand the issues and processes under consideration.

Paper Organization

This paper is organized into six sections. Section 1 provides general ratemaking principles that guide Commission rate design and explains the rationale behind these principles. Sections 2 and 3 (Revenue

[5] Based on questions posed in the January 12, 2010 Scoping Memo, R. 09-08-009, pgs. 9 & 11

Requirement and Revenue Allocation, respectively) consider the three steps described above. Section 4 provides background on the types and objectives of different rate designs, examines existing rates and special considerations for new PEV rates. Section 5 discusses strategies for encouraging PEV adoption and Section 6 provides conclusions, recommendations and questions.

SECTION 1: RATEMAKING PRINCIPLES AND METHODOLOGIES

The revenue allocation and rate design analyses provided in this paper adheres to a variety of principles and methodological approaches. This section identifies and provides an overview of these principles and methodologies.

1.1 ENERGY ACTION PLAN

The PUC's cost-setting and ratemaking policies are consistent with the Energy Action Plan (EAP) II, adopted by the PUC and California Energy Commission (CEC) in 2005, and updated in February 2008. The EAP identifies six sets of actions of critical importance, including optimization of energy conservation and resource efficiency, acceleration of California's goal for renewable generation, reliable and affordable electricity generation, and the upgrade and expansion of the state's electricity T&D infrastructure.

1.2 REVENUE REQUIREMENT

In California, cost-of-service regulation is based on periodic forecasts of IOU revenue requirements. The revenue requirement is equivalent to the sum total of the IOU's forecast cost of providing service, represented by the sum of operating expenses, depreciation, taxes and a rate-of-return allowed on the utility's investment, for the period under review, while accounting for annual attrition, or inflation adjustments, typically adopted for a 3-year "test period."

The rate-of-return is determined by analyzing the components of the utility's capital structure in order to arrive at a composite return adequate to meet the utility's capital requirements; in other words, to reflect the cost of debt and provide a fair return on equity capital. Investments, or capitalizable costs, on which utilities are permitted to earn a return, are collectively referred to as ratebase. The ratebase is the book value of the generation, distribution and transmission infrastructure assets owned and operated by the utility. The revenue requirement is the total allowable revenues to be collected, via rate schedules, from various classes of customers.

In 1982, California adopted a decoupling policy that broke the link between energy sales and revenues. Decoupling ensures that utilities achieve their CPUC-approved earnings even if energy conservation programs reduce sales.[6] Typically, excess revenue is returned to ratepayers and any shortfall is collected from ratepayers in subsequent periods. As a result, investor owned utilities (IOU) no longer have a built-in incentive to promote consumption in order to maintain their earnings, which has allowed California's per capita energy consumption to remain flat over the past thirty years.

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[6] In 1982, California adopted an Electric Revenue Adjustment Mechanism (ERAM) and became the first state to decouple utility revenue from sales, removing disincentives for energy efficiency and conservation. Revenues from electric sales are limited by the ERAM, therefore, incremental sales will not increase revenues. What is argued in this paper is that though the IOU is not collecting more revenues the average cost is decreasing because it is spread over more kWhs, thus the margin, between revenues collected and costs incurred, increases. It is the substantial increase in kWhs, from PEVconsumption, that contributes to the margin.

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Costs that can be fairly accurately forecast and budgeted are examined and approved by the Commission in General Rate Case (GRC) proceedings. These proceedings are on a three year cycle. The revenue requirement forecast is reviewed and adopted for the first year of the cycle, known as the test year, and an attrition rate is applied to adjust subsequent years for expected inflation. Typically, the revenue requirement is determined in the Phase 1 GRC.

In Phase 2 of the OIR the Commission may need to consider whether to direct utilities to seek cost recovery through the GRC process or through special Application. IOUs file applications for GRCs, but they also file special applications for rate increases, mergers, certificates for construction of large projects, etc. General rate cases utilize established marginal cost methodologies but other applications may explore other methodologies for quantifying impact or cost/benefit frameworks. GRCs examine planned forecasted capacity upgrades in a comprehensive manner whereas applications may arise in response to unplanned capacity upgrades. Often the type of application filed by the IOU is a matter of timing, because IOUs are on different GRC schedules.

For the early PEV market (e.g., prior to 2015), applications may allow utilities to be flexible in planning for cost recovery outside of the GRC process. Applications may be appropriate in the interim given the uncertainties around PEV market penetration. If this approach were deemed appropriate, the Commission may in turn need to adopt a tracking mechanism for PEV-related utility expenditures.

This issue as it arises in the context of this Rulemaking may be informed by recent Commission precedent set in the Smart Grid Rulemaking (R. 08-12-009). In D.10-06-047, the Commission concludes "that a utility may seek approval for Smart Grid investments either in its GRC and/or through separate applications"...[and that]..."either review path – as part of a GRC review of investments or in a separate application – offers a practical way to review proposed investments."[7] The review path by which IOUs seek recovery of expenditures related to PEVs is an issue that requires resolution in Phase 2 of the OIR.

Utility costs are typically categorized into three major components: generation, distribution and transmission. This categorization not only reflects major areas of utility operations but is also utilized in allocating costs to various customer classes, given that some customers do not receive full bundled[8] service from the utility.

Utility fuel and power purchase costs are reviewed and approved by the Commission in annual Energy Resource Recovery Account (ERRA) proceedings. These approved power procurement costs are passed through the revenue requirement and collected directly from ratepayers. These costs are not included in the rate of return calculation.

1.3 REVENUE ALLOCATION AND RATE DESIGN

[7] D.10-06-047, p.95

[8] Bundled refers to utility provided services (e.g. generation, transmission, distribution, etc.) summed to one aggregate rate. Some customers (e.g., direct access or community choice aggregation customers) pay an unbundled rate that does not include generation costs.

Revenue allocation and rate design are the topics typically addressed in Phase 2 of a GRC. Ratemaking principles adhered to in the rate design process rest on concepts of fairness and equity, with respect to both the utility and the customer.

In theory, rates are based on cost causation. The objective of a rate structure is to enable the utility to collect its revenue requirement without creating inequity between customer classes; burdening one for the benefit of another. Proper rate design results in rates for classes of customers that are proportionate to the cost of serving each class of customer and which serve to encourage efficient utilization of the system. Pricing structures therefore fall between two theoretical extremes: individual tariffs for each individual customer and identical tariffs for all customers.

To successfully integrate PEVs, reliance on broader Commission guiding principles may be helpful. For example, PEV rate design could generally conform to the following dynamic rate design guidance identified in Decision (D.) 08-07-045[9] in Phase 2 of PG&E's 2007 GRC:[10]

- Rate design should promote economically efficient decision-making.
- To promote economically efficient decision-making, rates should be based on marginal cost.
- Other objectives such as energy efficiency, and legal requirements such as baseline allowances, should be addressed when designing specific rates, and any deviation from marginal cost should be minimized.
- Rates should also seek to provide stability, simplicity and customer choice.

[9] http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/85984.pdf at p.47

[10] Though rate design guidance provided in D.08-07-045 was provided within the context of dynamic rates and was specific to PG&E, the other IOUs have since adopted these overarching principles. (SCE A.09-12-024, SDG&E A.10-07-009)

SECTION 2: REVENUE REQUIREMENT ISSUES RELATED TO PEV LOAD

In response to question 28[11], posed in the August 20, 2009 Rulemaking (R.) 09-08-009, parties agreed that the types of costs and benefits on different aspects of the electricity system, generated by PEV adoption, are an area which requires further study. Phase 2 of this OIR on Alternative-Fueled Vehicles must explore the costs and benefits of PEV deployment. This is a two step process. Identify costs and benefits, as discussed in this section, and then allocate costs and benefits, as discussed in Section 3. After identifying the costs and benefits associated with the additional PEV load and determining which of these costs are appropriately borne by the individual customer, the resulting revenue requirement can be determined.

This section considers issues related to assessing the revenue requirement for PEV load. The first step in this process is to identify costs and benefits in order to determine the total increase in net cost[12] of service associated with the new load.

2.1 NATURE AND EXTENT OF EXPECTED COSTS

PEV charging location, timing, voltage, and response to demand-side management signals influence potential electrical system impact costs. The cost implications of off-peak versus on-peak charging scenarios are vastly different, and depend on the existing customer service amperage. Preliminary utility analysis suggests that distribution upgrade costs to accommodate charging for residential circuits may be as much as <u>five to twenty times greater</u> on-peak as compared to off-peak.[13]

There exist two issues with regard to expected costs related to PEV load:

1) The potential for a new peak, and
2) The adequacy of the distribution and transmission system serving certain neighborhoods

In comments to the proceeding, parties identify potential distribution system impacts associated with coincident, geographically clustered PEV charging, particularly for Level 2 charging (e.g., 240V at 30A) on certain residential circuits. This impact is particularly an issue for charging that occurs on-peak, or shoulder periods, creating a "new" peak load issue. Issues related to mechanisms to allow the utility to offer direct charging management services to stagger charging times and mitigate this new peak concern will be discussed in greater detail in a subsequent options paper to be released in advance of the Smart Grid/Alternative-Fueled Vehicle workshop in November.[14]

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[11] 28. What types of costs and benefits are generated by electric vehicle adoption on different aspects of the electricity system, including transmission, distribution and procurement costs?

[12] Note that it is revenue, not cost, that is allocated, because it is the ratebase cost plus the rate of return that makes up the total allowable revenues to be collected from ratepayers. In other words, the cost to a ratepayer of a new transformer is not just the fair value of the ratebase asset but the fair value plus a rate of return on that value.

[13] PG&E T&D analysis. PG&E's analysis tests Level 2 charging based on utility estimates of market preference for Level 2 charging. This analysis was provided during an April 15, 2010 meeting with Energy Division staff.

[14] August 9, 2010 ALJ Ruling on Phase 2

Utility preliminary analysis[15] on this issue suggests certain customer premises (particularly in climate zones where A/C is not needed and thus the distribution system was not sized for seasonal or intermittent large loads) may require secondary line drop upgrades, transformer size upgrades, and primary line upgrades to support PEV charging. In contrast to residential PEV charging, a commercial service with a larger A/C demand typically already would have higher voltage service, supported by existing distribution infrastructure, and therefore can accommodate a greater amount of off-peak PEV charging. As expressed in comments, transmission system upgrades will likely be needed once the PEV market has matured and not at the outset. In the long-run, transmission system operators will need to determine whether clustered charging creates transmission constraints in load centers.

PG&E, SCE, SDG&E and DRA agree that even for off-peak charging, there will be an increase in costs. However, SCE states that in the near-term generation and transmission constraints are not urgent issues and should be discussed longer-term in the resource adequacy (RA) and long-term procurement proceedings (LTPP).

2.1.1 FACTORS AFFECTING COSTS

Both fixed and variable costs, capital and operating, must be examined. Using only energy or variable cost estimates, could underestimate the potential value provided by avoided generation capacity costs, as a result of off-peak charging. Exclusion of capacity upgrades or other fixed costs will provide conservative estimates of benefits.

Costs are location dependent. Preliminary utility testing of distribution system impacts due to PEV charging show distinct impacts for areas with less distribution system capacity (e.g., coastal areas) than for those with greater distribution system capacity (e.g. areas where customers frequently use air conditioning cooling load). Initial utility tests show distribution system upgrade costs may be greater per PEV in coastal areas.[16] Some utility forecasts predict that experience to date with dense hybrid vehicle (gas/electric without plug-in function) adoption prevalent in certain coastal communities may predict the geographic pattern of early market PEV adoption.[17] As a result, the early PEV market may require greater distribution capacity upgrades than may be expected to occur later in the market adoption curve for distribution zones sized to support air conditioning cooling load.

Costs may be class-dependent. Given that distribution systems are sized to peak load, typically, electricity infrastructure in commercial zones is more robust than infrastructure in residential areas. Consequently, the need for distribution system upgrades may be quite different for day-time and coincident charging in commercial areas as compared to residential.

Costs are charging-voltage dependent. Customer preference for charging voltage will be influenced in part by battery storage capacity, onboard DC outlet availability, customer's charging infrastructure and tariff choice and preference for recharge times. Level 1 (e.g. 120 VAC[18] at 15A) charging is not

[15] PG&E T&D analysis. PG&E's analysis tests Level 2 charging based on utility estimates of market preference for Level 2 charging. This analysis was provided during an April 15, 2010 meeting with Energy Division staff

[16] Pacific Gas & Electric, Presentation to March 16, 2010 Joint Agency Workshop

[17] Pacific Gas & Electric, Presentation July 15, 2010 Smart Grid workshop

[18] Voltage Alternating Current

expected by parties to pose significant distribution system issues.[19] However, some parties expect customers to prefer faster Level 2 (e.g. 240VAC at 30A, up to 80A) charging. The much more rapid DC fast charging is designed for commercial and public charging. The off-board DC charging equipment is typically served by a three-phase circuit at 480 or 600VAC.[20] The Society of Automotive Engineers has not yet approved a standard plug for DC charging, although it is considering an automaker industry standard.

Costs are also time dependent. Customer charging behavior will ultimately determine the PEV cost impacts on utility generation, transmission and distribution assets. Impacts may be difficult to assess given that TOU-based impacts can capture area T&D $/kW-yr capacity cost differences, but cannot capture need differences (e.g. timing or coincidence). This is not to say that TOU rates cannot capture generation differences, only that diversity of usage on each circuit is highly variable.

In the reliability context, customer outage costs are typically caused by storms, hot weather, or accidents. A distribution system upgrade necessitated by outage is considered economic if the cost of upgrading the distribution system is less than or equal to the outage cost that is avoided. Decision (D.) 04-10-034, in PG&E's 2003 GRC, requires IOUs to utilize distribution system reliability performance indices (e.g. SAIDI, SAIFI), measuring interruption frequency and duration. Granted most outages are non-capacity distribution system related, but to the extent that clusters of PEVs negatively influence SAIDI or SAIFI, it may be necessary to differentiate between interruptions expected from more routine outages and those expected from the new phenomenon of PEVs in order to determine the reliability impact of PEV clusters.

Lastly, rate design complexity may require costly upgrades to the utilities' billing systems.

2.2 NATURE AND EXTENT OF EXPECTED BENEFITS

This section describes the types of benefits that should be considered in relation to PEV usage. For the purposes of this analysis, this paper equates ratepayer benefits with ratepayer interests. As used in PUC Section 740.3, "interests" of ratepayers, short-or long-run, mean direct benefits that are specific to ratepayers in the form of safer, more reliable, or less costly gas or electrical service. PUC Section 740.3(c) states, "The commission's policies authorizing utilities to develop equipment or infrastructure needed for electric-powered and natural gas-fueled low-emission vehicles shall ensure that the costs and expenses of those programs are not passed through to electric or gas ratepayers unless the commission finds and determines that those programs are in the ratepayers' interest."[21] PEVs are expected to provide both direct and indirect benefits. Some benefits are quantifiable while others may serve only as supporting arguments in the cost/benefit analysis.

2.2.1 INFRASTRUCTURE-RELATED PEV BENEFITS

As noted in the introduction, there are significant benefits associated with increased PEV adoption that result from spreading fixed infrastructure (e.g. T&D) costs over a greater volume of kWhs. This benefit does not imply special treatment for PEV-related infrastructure upgrades, rather

[19] Southern California Edison, Opening comments to R. 09-08-009 OIR, p. 31

[20] Ecotality / eTec Electric Vehicle charging infrastructure deployment guidelines V. 3.1 at p. 5, May 2010

[21] http://www.leginfo.ca.gov/cgi-bin/waisgate?WAISdocID=38429921205+0+0+0&WAISaction=retrieve

it is a countervailing point that highlights the asymmetry in the quantity of PEV load compared to other new load. There are also operational efficiencies (with regard to generation) that result from increased nighttime consumption specifically, and flattening the state's load profile in general, including reduced shutdown or ramping of generators, increased utilization of nighttime wind and seasonal hydroelectric generation (and the associated reduction in GHG emissions when displacing fossil generation).

As stated by SDG&E in response to question 23[22], "allowing the capital cost to be spread over more kWhs, would result in lower cost per kWh." In the same way that utilities try to retain high-use, high-load-factor customers that share a large portion of the fixed costs otherwise shouldered by other customers, there exists a cost-reduction benefit in that 'new load' may offset the expected increase in fixed costs required to serve them. If a sufficient contribution to fixed costs is made then other ratepayers may be held indifferent.

To prove that the new PEV load might offset costs, one must conduct both a short-run and long-run impact analysis based on one's assumptions regarding electric vehicle market penetration. It is conceivable that a new and substantial increase in load may result in a lower average variable generation cost and reduced average fixed T&D costs per all kWhs sold. The most advantageous conditions for PEVs are where utilities have high fixed T&D and low variable generation costs and ultimately and is dependent upon "whether average variable costs associated with the additional generated or purchased power necessary to serve the P[H]EVs are greater than or less than the reduction in average fixed cost achieved by spreading fixed costs over more kWh."[23]

As described in the 2009 Policy and Planning Division White Paper[24], and as SCE stated in response to question 28[25], posed in the August 20, 2009 Rulemaking (R.) 09-08-009, "capital costs are expected to be concentrated in localized distribution circuits or transformers with increased O&M costs to facilitate consumer adoption. The degree to which customers' charging patterns improve overall system load factors will help quantify the net physical system and procurement benefits of PEV market expansion." **PEV charging could represent a new and substantial increase in load. However, if the load factor of each utility, the ratio of average to peak demand, is low this can indicate a utility's generating capacity would be used more fully, or efficiently (reducing the cost per kWh consumed), if load were more evenly distributed.** One way to increase load factor is to encourage customers to shift portions of their demand that coincide with the utility's peak load to off-peak periods. Rates and demand-side management mechanisms can be used to create a more evenly distributed load, which allows for more cost effective system operation.

In assessing PEV benefits, the value to all ratepayers of improved wind supply throughput, both as a supply side resource advantage and cost advantage, to meet off-peak PEV demand, must also be

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[22] 23. In the long term, what are the benefits and drawbacks on electric generation and transmission associated with projected PHEV and BEV market growth in California?

[23] Impacts Assessment of Plug-In Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids: Part 2: Economic Assessment; Scott, Kintner-Meyer, Elliot, Warwick, PNNL; November 2007; p.14

[24]CPUC PPD white paper: "Light-duty vehicle electrification in California: Potential Opportunities and Barriers," 2009. http://www.cpuc.ca.gov/NR/rdonlyres/AD8A4A5E-6ED9-4493-BDB6-326AB86A028E/0/CPUCPPDElectricVehicleWhitePaper2.pdf

[25] 28. What types of costs and benefits are generated by electric vehicle adoption on different aspects of the electricity system, including transmission, distribution and procurement costs?

quantified. In response to question 29[26], DRA stated that "off-peak [P]EV loads cause virtually no marginal capacity costs." In addition, ratepayers benefit directly from the avoided costs associated with shut-down and start-up of peaker units and increased utilization of baseline generation. Filling in the nightly load valley can reduce average costs per kWh and greenhouse gas (GHG) reductions will occur by replacing fossil generation with renewable generation.

2.2.2 OTHER PEV BENEFITS

Under the AB 32 Cap and Trade program that the Air Resources Board is currently developing, any decrease in the state's GHG emissions will result in a lower demand for GHG compliance instruments, which will in turn lower the total societal cost of the program. The 2009 Policy and Planning Division White Paper made preliminary findings (see Table 1) regarding GHG emission reductions as a result of various PEV population forecasts:

Table 1 Draft Impact of PEVs on GHG emissions

PEVs in 2020	Increased GHG emissions from electricity generation (MMtCO2e)	Net MMtCO2e Reductions, accounting for avoided emissions from reduced gasoline consumption (MMtCO2e)
3,000 BEVs 58,000 PHEVs	0.083	(0.158)
33,000 BEVs 312,000 PHEVs	0.460	(0.900)
455,000 BEVs 2,500,000 PHEVs	0.620	(7.730)

Additionally, the Low Carbon Fuel Standard (LCFS)[27] classifies electricity fuel as an "eligible fuel pathway"[28] for electricity fuel deliverers in California, which amounts to a transfer of responsibility from the transportation sector to the utility sector. The LCFS will develop protocols for measuring the "life-cycle carbon intensity" of transportation fuels in the process of meeting a 10% reduction in intensity by 2020. LCFS credits may represent a large financial benefit for the utility sector and to some degree, the ratepayer. In response to question 33[29], parties diverged on who exactly should receive the direct benefits of any "credits" generated by reduced greenhouse gas emissions resulting from increased electrification.

Following identification and forecasting of costs and benefits to be realized from PEV adoption, there will be a need to determine whether, on a net present value basis, a net cost or net benefit will be

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[26] Ibid

[27] http://www.arb.ca.gov/fuels/lcfs/030409lcfs_isor_vol1.pdf

[28] Defined as, the combinations of feedstock, production technologies, and/or fuels that qualify as renewable fuel and which are categorized to meet certain Energy Independence and Security Act of 2007 (EISA) requirements.

[29] 33. What recommendations, if any, should the Commission make to the California Air Resources Board regarding the treatment of electricity under the Low Carbon Fuel Standard?

imposed on the system. In either instance it is important that costs and benefits be tracked in order to inform the capacity planning process and assure cost recovery for those expenditures deemed recoverable by the Commission.

2.3 NET COST RECOVERY

A methodology for quantifying PEV specific costs, net of benefits, for multi-year PEV market penetration forecasts may need to be developed. **This would require differentiating between PEV load separate from other new loads (to the extent this is feasible from an engineering perspective); establishing criteria for determining (and a mechanism for tracking) identified costs; and ultimately allocating the net costs (e.g. after taking into account offsetting benefits).**

Tracking costs incurred for PEV-specific infrastructure upgrades is essential not only to providing more accurate extrapolation and capacity planning in future years, but in accurately accounting for costs and recovery of those costs. As an alternative to traditional ratemaking, the Commission has utilized the following tracking mechanisms in the past:

- Balancing accounts that allow IOUs to track and recover authorized costs and/or benefits (the balance is reconciled at year-end and carried over and applied to the following); and
- Memorandum accounts that allow IOUs to track costs that may or may not be recoverable in rates and which are subject to further scrutiny by the Commission via an after-the-fact reasonableness review.

Establishing either mechanism may represent an interim step, until IOUs present testimony in their next GRC that addresses all PEV-specific generation, transmission and distribution upgrades in an integrated fashion. The duration of this interim period is a topic deserving of further discussion.

2.4 ADDITIONAL CONSIDERATIONS FOR THE DETERMINATION OF TIME-OF-USE BASED COSTS AND BENEFITS

In response to question 29[30], posed in the August 20, 2009 Rulemaking (R.) 09-08-009, some parties called for tariff structures that reflect real-time costs and benefits. As stated earlier, though rates are designed to be cost-based, currently rates are based upon embedded costs identified in the GRC process and not on real-time wholesale or CAISO nodal conditions. However, if long-term marginal costs are greater than embedded costs, to the extent that service demands are elastic, rate designs can encourage customer conservation. The difficulty, however, arises in determining precisely what represents marginal cost and how to modify that value to match a total revenue requirement.

[30] 29. Should the electric vehicle rate structure be designed to align rates with the system costs and benefits of PHEVs and BEVs, and if so, how? Should the Commission assign additional costs and benefits attributable to PHEVs and BEVs to specified electric vehicle rate classes or socialize the costs and benefits attributable to PHEVs and BEVs to all customer classes? Should the PHEV and BEV rate classes bear existing rate component costs?

SECTION 3: ALLOCATION OF EXPECTED COSTS / BENEFITS RELATED TO PEV LOAD

As given in the introduction to Section 2, the second step in the regulatory process is allocation of costs and benefits. Allocation requires an understanding of traditional ratemaking tools of cost apportionment and electric rules and terminology. Proper revenue allocation, as discussed in Section 1.3, results in rates for classes of customers that are proportionate to the cost of serving each class of customer and which serve to encourage efficient utilization of the system. Allocation pertains to apportionment of infrastructure and operating costs. The electric rules, however, differentiate between system costs and costs borne by the customer.

3.1 REVENUE ALLOCATION

Revenue allocation is the process by which the portion of each customer class' revenue responsibility is determined. In the GRC context, marginal cost methodologies are utilized in arriving at a forecasted marginal cost for each cost function (e.g. generation, distribution). An equal percentage multiplier is then used to adjust the aggregate functional marginal cost revenue to the actual revenue requirement.

Allocation factors provide for varied treatment of the shared costs and benefits depending on their nature. Demand, or fixed capacity, costs which represent fixed plant investment, at a level of operations needed to meet the maximum service demands placed on a system, are costs that continue regardless of service rendered, since the peak service must be available whenever demanded. These costs do not diminish when the plant is inactive and are generally allocated to customers based on their contribution(s) toward total demand at the maximum operating level. Commodity, or variable, costs which represent costs that fluctuate with consumption are generally allocated based on consumption in kWh. "Customer costs" reflect other fixed costs, and arise by virtue of the fact that the customer exists (e.g. bills and bill preparation). These costs are generally allocated based on the ratio of customers in the class to total customers. Common costs are those which are necessary to operate the system without regard to the levels of usage or number of customers (e.g. Administration & General expenses).

As will be discussed further in Section 4, directly assignable costs may take the form of a separate non-volumetric charge. Identifying and isolating the components of distribution investment necessitated by the need to serve additional load may prove challenging, but existing tariff electric rules provide precedent regarding how and where that boundary is traditionally drawn.

3.2 ELECTRIC RULES

IOUs allocate specific costs to a customer based on existing electric tariffs. **An understanding of the electric tariff rules described in this section is essential, prior to considering potential PEV rate modifications. Since PEVs were not contemplated when these Rules were adopted, it is necessary to determine whether existing Rules imply inclusion or must make PEV inclusion explicit.**

Tariffs detail rates, charges, rules, service territories and terms of service, all of which are filed for approval, per General Order (GO) 96-B, with the Commission. **Tariffs govern legally binding**

contracts[31] **between the utility and its customers. The rate schedules, contained within the tariffs, include electric rates, charges and other terms of service to individual customer classes (e.g.. residential, commercial, industrial, agricultural, streetlight, etc.).** Electric rules serve as complements to rate schedules and detail the terms of service. Before any changes can be made to utility tariffs, an application and/or advice letter must be filed with, and approved by, the Commission. Revisions to tariffs are subject to PUC Section 761. Some electric rules determine which costs are standard, and to be ratebased, and which are special and paid directly by the individual customer. Electric rules are almost identical for all IOUs.

Current tariff treatment considers service capacity upgrades to an existing customer as a 'permanent new load'. This treatment has implications in that the cost of the required system upgrade is typically ratebased. Per IOU responses to an Energy Division data request dated August 13, 2010, existing customers that charge PEVs on premises, requiring a service upgrade currently are treated as 'permanent new load.'

As it stands, any system capacity upgrades upstream (meaning on the utility system side) of the service point (typically very close to where the meter is located), would not be charged to the individual customer adding the load, as long as the customer does not exceed the allowance. The allowance will be described further in Section 3.2. Under current rules, neighborhood distribution system upgrades triggered by customer installations of electric vehicle charging facilities are treated the same as upgrades triggered by any 'new load', and their cost is ratebased. In other words, there exists no special treatment for neighborhood distribution upgrade costs driven by PEV market penetration. However, under current rules, should the customer's existing service equipment not be able to accept the additional load, the customer, at his/her own expense, would need to install a larger, or additional, service panel capable of accepting the added load. In summary, upstream of the service point, system upgrade costs are ratebased, while downstream (customer side of the service point) the customer is responsible for the costs.

Per IOU responses to an Energy Division data request dated August 13, 2010, failure to notify the utility of new load, per tariff Rule 14, even if not requiring a service upgrade, may result in adverse distribution system impacts and the customer increasing the load will be required to pay for whatever corrective measures the IOU determines are necessary.[32] **Phase 2 of this OIR must reevaluate whether or not PEV charging conforms with the tariff definition of 'new load' especially with higher penetration, and if PEV charging is considered 'new load' whether it is subject to the same, or different, allowance provisions or dispensation afforded other 'new load.'**

What follows is an examination of Electric Rules 2, 15, 16, 18 and 21. Rule 2 provides a 'Description of Service' as it relates to voltage delivered to the customer. It provides a foundation for more specific types of service described in subsequent Rules. Rules 15 and 16 are applicable to extensions of existing service, primary and secondary, respectively. Given the mix of charging level, meter and rate

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[31] Tariffs that have been approved by the PUC are binding legal documents and must be made available to the public; Resource: An encyclopedia of energy utility terms, 2nd Ed., p.444

[32] August 13, 2010 data request posed question 2, given as, (2) For existing customers, electricity rules require that existing customers notify the utility when they increase their load beyond the existing service. In practice, are there any industry norms that electricians follow for determining what constitutes a change in load? How and when do customers or electricians notify the utility of a "change in load?" Please also describe how the utility has dealt with a PEV owner who has failed to notify the utility of the presence of the PEV. In your response, please detail whether the customer's failure to notify the utility resulted in adverse distribution system impacts.

options available to PEV owners, it bears comparing service impacts that arise from 'new load' relative to impacts that arise from PEV charging versus other 'new load'. Rule 18 pertains to the 'Supply to Separate Premises and Submetering of Electric Energy' and therefore is relevant in the multi-dwelling context. Rule 21 describes 'Generating Facility Interconnections' for distributed resources such as wind and solar and is relevant in that PEVs may be treated similar to generation when used as storage in the future.

Currently the utility is obligated under Electric Rule 2[33] to maintain the nominal service voltage to its customers. As a customer adds **'new load'** to their existing service, should the service voltage level fall below the minimum given below, the utility must take corrective action to restore the service voltage to its minimum level or better. The utility will maintain the proper voltage level at utility expense. That is to say those, costs incurred in maintaining service are ratebased.

Rule 2

Electric Rule 2.B.2.a, "Customer Service Voltages", states in part, that under all normal load conditions, distribution circuits will be operated so as to maintain secondary service voltage levels to customers within voltage ranges specified as given in Table 2 below.

Table 2

Nominal Two-Wire And Multi-Wire Service Voltage	Minimum Voltage To All Services	Maximum Service Voltage On Residential and Commercial Distribution Circuits	Maximum Service Voltage On Agricultural And Industrial Distribution Circuits
120	114	120	126
208	197	208	218
240	228	240	252
277	263	277	291
480	456	480	504

For example, if a PEV owning ratepayer that charges at Level 2 is located reasonably close to the transformer, particularly in a climate zone where many customers have air-conditioning, then it is likely that that customer will be delivered in excess of 120V and an upgrade may not be necessary. However, if the customer is located at the greatest distance from the transformer and the delivered voltage drops below the minimum 114V (120 V with residential circuit tolerance of +0%/-5%), then the IOU will be obligated to upgrade that customer's service. Recognizing that the customer is responsible for all costs behind (aka. downstream) of the service point/meter which includes the service panel, the cost of the service upgrade upstream of the service point/meter is dependent upon the age, capacity and location of secondary wiring, the transformer, and primary wiring.

It bears noting that there exists a distinction between standard installation and **'special facilities.'** Standard installation typically represents the overhead service, closest to the primary line, the cost of

[33] Tariff Rules; Retrieved from http://www.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE2.pdf

providing which, is collected in the distribution component of the each ratepayer, up to the allowance. In other words, the upgrade cost is shared amongst all customers in that class. Special facilities, however, are those, as defined by Rule 2, that are non-standard and paid by the customer only, and at cost. These facilities can include, but are not limited to underground service, power quality conditioning equipment, customer connection costs, installation of facilities downstream of the meter, facilities where the cost is in excess of the standard extension allowances, and alternate service equipment. Monthly maintenance fees are also paid by the customer for special facilities.

Rule 2(i)2 defines 'special facilities' as "facilities requested by an applicant which are in addition to or in substitution for standard facilities which [the utility] would normally provide for delivery of service at one point, through one meter, at one voltage class under its tariff schedules, or a pro rata portion of the facilities requested by an applicant, allocated for the sole use of such applicant, which would not normally be allocated for such sole use. Unless otherwise provided by [the utility's] filed tariff schedules, special facilities will be installed, owned and maintained or allocated by [the utility] as an accommodation to the applicant only if acceptable for operation by [the utility] and the reliability of service to [the utility's] other customers is not impaired."[34] Rule 2(i)2(a) goes on to state that "where new facilities are to be installed for applicant's use as special facilities, the applicant shall advance to [the utility] the estimated additional installed cost of the special facilities over the estimated cost of standard facilities" As an alternative the customer may pay a finance charge within the monthly cost-of ownership charge which covers maintenance of the special facility."[35] Per IOU responses to an Energy Division data request dated August 13, 2010, PEV charging upgrades currently constitute standard facilities and are not subject to the 'special facilities' provisions.

A number of factors typically contribute to the need for PEV-related distribution system upgrades. These include, but are not limited to, the number of homes on the same transformer, the age of the homes, the capacity to which the transformers were sized and whether the home is in an air conditioning concentrated region, the location and type of transformer, diversity factor [36]assumptions, the length, size, configuration, and number of secondary conductors, the size and length of service conductors feeding customers with charge stations, and the timing and voltage of charging.

With regard to transformers, underground services or pad-mounted services, are characteristically of larger capacity and easier to maintain than overhead transformers. Though underground transformers may possess the capacity to serve a greater number of homes, they also typically have much lower diversity factors than overhead transformers. Overhead services, or pole-mounted services, have weight constraints and are typically of smaller capacity and more difficult to maintain. Overhead transformers have the capacity to serve fewer homes and larger diversity factors as a result.

Residential single-phase, three-wire distribution service delivers one two 120V phases to neutral and 240V between the two phases. A typical residential 200A service panel, downstream of the meter, has a series of 15A or 20A sub-breakers. Typically these sub-breakers total to greater than 200A based on assumptions regarding diversity of usage. A Level 2 charger will draw 240V through 30 or 40A, providing, without accounting for loss, 7.2kw or 9.6kw, respectively. **Depending on the coincident**

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[34] http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_2.pdf

[35] Ibid

[36] Diversity factor, defined as, the ratio of the sum of the individual non-coincident maximum demands to the maximum system demand. Diversity occurs when the maximum demand, or peak, occurs at different times. The degree of diversity depends on customers' energy-use patterns.

load on the service panel, and the amperage rating of that panel, the customer may need to upgrade his/her panel to allow for concurrent vehicle charging and home use. Commercial and industrial services may have a higher amperage and/or voltage to accommodate incremental load dedicated to PEV charging than a typical residential service.

The utility distribution system is divided into primary and secondary services. The line of demarcation between the two is generally the primary side of the distribution transformer. Upstream of the transformer is the primary, comprised of substation transformer banks and main feeder lines. In response to question 20[37], parties noted that preliminary analysis shows that impact associated with Level 1 or 2 charging on the primary, at least at low penetration of PEV charging, are rather small. Downstream from, and including, the distribution transformer to the service point/meter is the secondary. The boundary between the utility and its customer is discussed in the Staff Issue Paper entitled "Utility Role in PEV Charging" henceforth referenced as the "Roles" Paper. PEV charging impacts are expected to be more pronounced on the secondary facilities.

Rules 15 and 16

Electric Rule 15[38] pertains to 'primary' services. This Rule is applicable to extension of new electric distribution lines of utility's standard voltages necessary to furnish permanent electric service to applicants. Distribution lines refer to the utility's overhead and underground facilities which are operated to provide distribution voltages as set forth in Rule 2, and which are designed to supply **two** or more services/premises. A distribution line upgrade may be required if a transformer is added or replaced or load added..

Electric Rule 16[39] pertains to 'secondary' services. This Rule is applicable to both utility service facilities that extend from utility's distribution lines to the service delivery point. Service facilities include underground or overhead service conductors, poles, transformers, utility-owned metering equipment and other utility-owned service related equipment. An upgrade of secondary wiring may be required following either a service panel upgrade or addition of a second service panel, depending on the rated ampacity[40] of the second service panel.

Per Rules 15 and 16, the customer has the option to have a utility-approved contractor design and/or perform the installation of the new load upgrade. However, the utility must inspect and connect the new facilities to their system. By law and per Rule 16(a)4, only the utility can own and operate utility facilities. In other words, the utility is not required to serve over private lines. The installed facilities must therefore become the property of the utility and be maintained by the utility.

Per Rule 15, allowances are provided towards the cost of upgrades for new load.. The allowance for residential load is a fixed amount. The allowance for non-residential load is based on forecast consumption. If the cost of the <u>secondary</u> system upgrade is less than or equal to the allowance, the

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[37] 20. What are the potential electrical distribution system impacts associated with geographically concentrated PHEV and BEV charging in the near-term? How will utilities anticipate these impacts and make capital investments needed to ensure service network reliability? How should the utility capital investments be paid for and recovered?

[38] Tariff Rules; Retrieved from http://www.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE15.pdf

[39] Tariff Rules; Retrieved from http://www.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE16.pdf

[40] Defined as, the maximum amount of current a cable can carry before sustaining immediate or progressive deterioration

customer, residential or non-residential, pays nothing upfront. The allowance represents a prepayment of future ratebase expenditures to be repaid over time by all ratepayers. If the cost of the system upgrade is greater than the allowance then the customer, residential or non-residential, must pay the difference. If the cost is less than the allowance the excess can be applied to the primary system upgrade cost.

A refundable amount, however, is the amount paid by a customer toward the cost of an oversized, or non-standard, primary system upgrade that is utilized by the customer, or other customers', over a ten year period. The customer is refunded a portion of the capital cost when additional load is added to the primary line. Only actual refunded amounts are added to the rate base. Customers have a non-refundable option of paying half the upgrade costs for the primary system only.

As 'new load', PEV-related capacity upgrades are eligible for allowances. Should this treatment still apply once PEV charging penetration increases, and should the upgrade cost exceed[41] the allowance, then the residual costs must be allocated equitably; either through a customer charge (if not constrained by Senate Bill 695), establishment of a new rate class, or by revisiting electric rules. If the net cost is less than, or equal to, the allowance then PEV load is treated as any new load. Similar to the PEV charging load contribution to margin benefit cited in Section 2.2.1 an allowance is only granted for upgrades that represent new load because the new load will generate distribution revenues, which will contribute to the fixed cost of the capacity upgrades. Therefore, each new load represents a new allowance.

Electric Rule 15(c)1, pertaining to the primary distribution system, dictates that the utility will "complete a Distribution Line Extension without charge, provided [the utility's] total estimated installed costs do not exceed the allowances from permanent, bonafide loads to be served by the Distribution Line Extension within a reasonable time, as determined by [the utility]. The allowance will first be applied to the Residential Service Facilities [aka. the secondary], in accordance with Rule 16. Any excess allowance will be applied to the Distribution Line Extension to which the Service Extension is connected [aka. the primary].

The allowance, as given in (SCE) Rule 15(c)2 for Distribution Line Extensions, Service Extensions, or a combination thereof is based upon a revenue-supported methodology equivalent to the quotient of forecast Net Revenue divided by a Cost-of-service factor.[42] The non-residential allowances are based on the above referenced formula. The residential allowance is currently fixed at $1918, $2322, and $2026 per meter, or residential dwelling unit, for PG&E, SCE and SDG&E, respectively, based on the IOU-specific net distribution revenue associated with the average residential consumption.

Electric Rule 16(a)2, pertaining to the secondary distribution system, defines Service Facilities as those facilities that consist of "primary or secondary underground or overhead service conductors, poles to support overhead service conductors, service transformers, [utility]-owned metering equipment, and

[41] It should be noted that per Rule 15(D)4 costs in excess of the allowance are considered a taxable contribution to the IOU and therefore incur an income tax component of contribution (ITCC). In other words, in addition to the costs in excess of the allowance the customer has to pay approximately 30-40% tax on this amount to the IOU to compensate it for the ITCC.

[42] The cost-of-service factor includes assumptions with regard to asset life, depreciation schedule, kWh 'new load' assumptions and other considerations

(e) other [utility]-owned service related equipment."[43] Ownership of service facilities, as given in Rule 16(a)3, if installed under the provisions of Rule 16, "shall be owned, operated, and maintained by [the utility] if they are located in the street, road or Franchise Area of [the utility], installed by [the utility] under section D.2 below on Applicant's Premises for the purpose of the delivery of electric energy to Applicant, or installed by Applicant under the provisions of this rule, and conveyed to [the utility]."[44]

Currently system upgrades that are due to 'new load' from a PEV are not explicitly referenced in the tariff rules. However, for the sake of example, if a residential PEV owning customer in PG&E's territory upgrades his/her secondary services to accommodate PEV charging and the cost to do so is equal to, or less than, $1918, then the ratepayer pays nothing upfront and the cost is ratebased. If a non-residential customer, a public charging facility owner perhaps, upgrades its secondary services to accommodate PEV charging and the cost to do so is equal to, or less than, the Net Revenue divided by a Cost-of-service factor, that customer pays nothing upfront.

Table 3 below, describes the difference between existing and new service as it pertains to new load for residential and non-residential customers. Existing service is in reference to capacity upgrades on premises and New service represents capacity upgrades required due to no pre-existing infrastructure. Per Rule 15(C)1, should the secondary system capacity upgrade cost be less than the allowance, the excess will then applied to primary system upgrade costs.

Table 3

	Existing Service Capacity Upgrade		**New Service Capacity Upgrade**	
Designation	Primary (Rule 15)	Secondary (Rule 16)	Primary (Rule 15)	Secondary (Rule 16)
'New Load'	Refund Eligible; plus Excess Allowance	Allowance Eligible	Refund Eligible; plus Excess Allowance	Allowance Eligible
Residential		Fixed Allowance		Fixed Allowance
Non-Residential		Refund Eligible; Formulaic Allowance		Refund Eligible; Formulaic Allowance

Rules 18 and 21

Rules 18 and 21 are additional Rules that have implications for our approach to facilitating integration of PEVs with multi-dwelling units (MDU) and with customers with onsite generation. There is of course the possibility of a MDU with onsite generation as well, for which these Rules are equally applicable.

[43] http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_16.pdf

[44] Ibid

Electric Rule 18[45] describes the terms of service to supply separate premises and submetering of energy. Rule 18(C)1 refers to residential multi-dwelling units (MDU) and Rule 18(C)2 refers to non-residential MDUs. Currently if a MDU is a master-meter customer and the tenants are not submetered, per Rule 18(C)2(b), the cost of electricity must be absorbed in the rent and the rent cannot vary with electric consumption. However, if the tenants or condo owners are submetered, customers using submeters must submit to [the utility] certification by a meter testing laboratory, satisfactory to [the utility], as to the accuracy of the submeters upon initial installation of such submeters, or for existing submeters upon request by [the utility]." The "Roles" Paper explores the issue of customer submeter ownership.

Electric Rule 21[46]**, the distributed generation (DG) interconnection rule, states that non-Net Energy Metering (NEM) customer generators (e.g.. customers that do not export) <u>are required</u> to pay for Distribution System Modifications to interconnect.** In theory, this would apply to a DG interconnection whether it exports or not which may be interpreted to include PEVs once vehicle2grid (V2G) technology is available. However, DG that does not export would rarely trigger Distribution System Modifications and therefore customers designated as non-NEM DG are not likely to have to pay costs of system upgrades. Currently NEM generators are exempted from Distribution System Modification costs entirely. They are also exempted from interconnection study costs. These costs are paid for in distribution rates. In the vehicle-to-grid (V2G) context, there might be some justification for treatment similar to this for residential PEV. It remains to be seen if PEVs will be regarded as NEM-eligible distributed resources.

Existing electric Rules are not specific in regard to PEVs. There is currently no differentiation between upgrades for Level 2 service and those for DC fast charging service. Both represent new load, just differing quantities. Phase 2 of this OIR will require examination of existing allowances, associated cost-of-service factors, refunds, and alignment with other distributed resources in order to further define terms applicable to PEV charging facilities.

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[45] http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_18.pdf

[46] http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf

SECTION 4: RATEMAKING CONCEPTS AND RATE DESIGN

Sections 2 and 3 discussed the issues associated with identifying and allocating individual and shared costs and benefits. The next step is to design a rate structure to recover the identified net costs in a manner that is consistent with the rate design principles discussed in Section 1 and that conforms with any charging behavior assumptions embedded in the cost calculations.

Rates have multiple objectives. One objective common across differing rate designs is cost recovery; **rates are a vehicle for remittance. However, the appropriate rate structure is dependent upon the end goal.** Flat rates offer simplicity. Inverted-block or tiered rates might promote conservation. Time-of-use (TOU) rates could lead to load shifting. Peak time rebates, or payments for short-notice load reduction, promote temporary demand reductions. The relative success of an electric rate meeting its objectives is dependent upon a customer's elasticity of demand. Demand is either elastic (if usage is expected to drop when price increases) or inelastic (if usage is not expected to decrease when prices increase). Generally, the value of a service is considered high if demand is inelastic and low if elastic.

Rates may have both fixed and variable components. Fixed charges are non-volumetric, may take the form of a customer or demand charge, and are typically based on marginal costs. Customer charges recover costs associated with dedicated distribution access facilities (e.g. meter). Demand charges represent a price signal to customers of the capacity costs they impose on the system. Typically, demand charges have only been applied to non-residential customers. In the context of PEVs, pending Commission authorization, a fixed demand charge for certain BEV customers who charge at higher voltages (say, 240V @ 80A) could be established based on the maximum demand on the distribution circuit, independent of whether the charging equipment throttles the BEV voltage down for a portion of the PEV charge. Variable charges are volumetric and typically take the form of an energy/commodity charge or other non-bypassable charges, which are discussed in further detail in Section 4.4.

Phase 2 will provide guiding principles, not set specific rates. IOU-specific PEV rates will likely be requested in applications filed by the IOUs upon conclusion of the proceeding. With this in mind, this section is divided into four subsections that focus on various rate design principles relevant to the PEV charging load. The first subsection identifies various rate structures. Subsection 4.2 describes examples of the existing IOU rates for residential and commercial customers. Subsection 4.3 considers the issues associated with developing a customer class specifically for PEV load. Finally, subsection 4.4 identifies topics that warrant special consideration in the context of developing a rate structure for PEV load.

4.1 RATE DESIGNS

This subsection describes the various existing rate structures that could be used to recover costs associated with PEV charging, including tiered (or block) rates, time-of-use rates, and combined rate structures.

Tiered Rates

Tiered rates are structured such that blocks, or tiers, of usage correspond to different rates (e.g. the higher the usage, the higher the rate). For the IOUs, the lowest tier is equivalent to a statutorily-mandated "baseline" amount and represents **"a significant portion of the reasonable energy needs" for a residential customer at the lowest cost** (see Table 4 below).

Baseline quantities, in kWh, are set in each IOU's GRC. The baseline amount is between 50 and 60 percent of average use for basic-electric customers in both the summer and winter and for all-electric customers in the summer. The Public Utilities Code[47] also requires that baseline quantities fall between 60 and 70 percent of average use for all-electric customers in the winter. Tiered rate structures are based upon the baseline, with inclining block tiers to promote conservation, whereas non-tiered rates have no such starting point. **The baseline amount is dependent upon the customer's location within the service territory, the season, customer's heat source (gas or electric), and medical needs, regardless of the size of home or number of occupants.**

Table 4

Tier 1	Up to the Baseline amount
Tier 2	Electricity usage from 101% to **130% of Baseline**
Tier 3	Electricity usage from 131% to 200% of Baseline
Tier 4	Electricity usage from 201% to 300% of Baseline
Tier 5	Electricity usage in excess of 300% of Baseline

Time-of-Use (TOU) Rates

TOU rates establish time periods which correspond to time period specific rates. TOU rates may be tiered or non-tiered. For example, PG&E's E-9 rates have three different time periods each assigned to tiers on a pro-rated basis. In other words, if 30% of a customer's usage is on-peak, then 30% of the total usage in each tier will be treated as on-peak usage. For a TOU rate, an average load profile is forecast and established because different rates are levied at different times of day. Generally, a **TOU rate is designed to be revenue neutral, in that, for an average load profile, the TOU rate is expected to neither increase nor decrease total revenues to be collected over the course of a year.** Deviation from the average load profile may not lead to recovery of total allowable revenues. It becomes necessary to track changes in load profile in order to account for revenue collection surpluses or shortfalls. **Historical and future usage will determine the appropriate PEV owner average load profile to be utilized in designing the new PEV rate. As stated, the iterative process of aligning rates with charging behavior may require the Commission to revisit rate structures for future adopters of PEVs.**

Combined Rate Structures

Some rates and charges are used in combination. An industrial customer may pay a two-part rate that consists of both a fixed demand charge and variable commodity charge. A residential customer may have an inverted-block or tiered rate with a minimum bill feature that permits recovery of customer costs. Or a customer may be on an interruptible rate whereby service can be interrupted by the utility during periods of peak demand on the system as an overlay on their otherwise standard residential rate. In this case, the customer would be compensated for granting the IOU the option to interrupt.

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[47] PU Code 739(d)1

4.2 RATES FOR PLUG-IN ELECTRIC VEHICLES

As stated in Decision (D.) 10-07-044, the "Commission retains jurisdiction over an investor-owned utility's sale of electricity to a charging provider or any other utility customer, even if the electricity is subsequently used as a motor fuel."[48] The investor-owned utilities over which the Commission has authority are PG&E, SCE, SDG&E, and a number of smaller investor owned utilities. The Commission also has authority over certain rate components (e.g. distribution-based) for electric service providers (ESPs). This authority is enforced via ratesetting.

The electric rate levied for electric vehicle charging services is dependent upon the provider, the location, the time of day and the recipient. For the customers of IOUs, including electric vehicle service providers as indicated in D.10-07-044, there are a number of types of rates (see Table 5 below) under consideration in Phase 2.

Residential rates pertain to the electric rate for customers who charge at home. Residential (private) rates will be bifurcated between single family homes and multi-dwelling units (MDU). Commercial rates, are applicable to customers who offer charging as a benefit of employment, fleet (private) charging, or patronage (public) charging. Those commercial rates that are specific to public charging are applicable to charging stations that are accessible to the public and provided by either a municipality or private entity. There may even be rates associated with roaming, across service territory, inter-utility rates. In response to question 27[49], parties evaluated a number of rate options for customers who charge in another utility's territory. Parties diverged in their approaches. Some favored service-based solutions, whereby the driver has a single billing relationship, and others believed the marketplace will determine the preferred method of payment. Perhaps no single approach is best, and only agreed upon principles shall be needed to ensure customer choice and simplicity. There are also rates charged by public or municipal utilities over which the Commission has no jurisdiction.

Table 5

PEV Rates	Private	Public
Residential:		
Single Family Home	X	
Multi-Dwelling Unit (MDU)	X	
Commercial:		
Employer or Fleet Owner	X	
Patronage:		
Municipality		X
Private Entity		X

[48] D.10-07-044, p.38

[49] 27. How should a customer pay when charging a PHEV or BEV in another utility's service territory? Please evaluate options set forth below, or suggest alternative approaches: a. A customer pays a posted price for electricity to a specific electric charging provider at the time of the transaction, similar to how gasoline is purchased. b. The second utility bills the customer's home utility and the home utility adds the electric vehicle electricity cost to the customers' energy bill. A third-party clearing house could facilitate these transactions. d. A customer has a relationship with a third party charging provider and pays that third party wherever the customer charges. e. A customer has a choice of all or some of the above options.

What follows is a description of current residential and commercial electric vehicle rates and air conditioning (A/C) rate incentives. Currently, PEV rates have a rather limited participation. Phase 2 of this OIR will need to determine to what degree existing rates can accommodate increased participation.

4.2.1 EXISTING RESIDENTIAL RATES

Currently, SCE offers two electric-vehicle-specific rates. Both TOU-EV-1 and TOU-D-TEV are opt-in, meaning that a customer can choose to use one of these rates instead of a regular residential rate. PG&E offers two residential electric vehicle rates, E-9a and E-9b. Per a October 24, 2009 Energy Division data request, PG&E stated that "E-9a and E-9b are opt-in only for NGVs (natural gas vehicles). E-9a and E-9b are mandatory for customers with a BEV (battery electric vehicle) or PHEV (plug-in hybrid electric vehicle)." [50] PG&E previously offered two other rates, E-9c and E-9d, which allowed PG&E to install a time clock that limited operation of the customer's PEV battery charger. E-9c and E-9d compensated the customer for this option by providing a lower rate. SDG&E offers three residential electric vehicle rates, EV-TOU, EV-TOU-2 and EV-TOU-3. All SDG&E PEV rates are opt-in and non-tiered. All existing PEV rates are TOU, but each has a different metering arrangement and on-to-off peak rate differential, Table 6 (see Appendix), and different TOU time period, Table 7a and 7b (see Appendix).

Currently, different rates have different metering arrangements. There are cost implications associated with different meter arrangements. A two-meter parallel arrangement, as discussed in the "Roles" Paper, requires a separate service panel which may prove more costly as it increases the potential amperage on the circuit, thereby potentially necessitating the upgrade of secondary services. A one-meter configuration with revenue-grade sub-meter, likely embedded in the electric vehicle service equipment (EVSE), would constrain usage to the existing amperage rating of the service panel. This may provide the customer sufficient capacity for charging on a non-coincident basis and not require upgrade of the secondary service, but may still necessitate IOU back office billing software upgrades.

Some existing residential EV rates require two meters

As noted in Table 6, SCE's TOU-EV-1, PG&E's E-9b, and SDG&E's EV-TOU and EV-TOU3 all require two meters. Only PG&E's E-9b and SDG&E's EV-TOU3 have a monthly meter charge. As discussed in the "Roles" Paper, all existing two-meter rates differentiate between PEV and non-PEV load.

SDG&E's EV-TOU-3[51] is an example of an efficient, customer cost-saving alternative. It offers ratepayers an opt-in, non-tiered TOU rate that includes a monthly charge for a parallel dual meter adapter (DMA). The utility owns the DMA but the ratepayer pays for the device. In this way, downstream of the meter, customer installation costs are minimized. The adapter provides for an

[50] PG&E E-9 TARIFF APPLICABILITY: This experimental schedule applies to electric service to customers for whom Schedule E-1 applies and who have a currently registered Motor Vehicle, as defined by the California Motor Vehicle Code, which is: 1) a battery electric vehicle (BEV) or plug-in hybrid electric vehicle (PHEV) recharged via a recharging outlet at the customer's premises; or, 2) a natural gas vehicle (NGV) refueled via a home refueling appliance (HRA) at the customer's premises. **This schedule is required for customers with a BEV or PHEV.** www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-9.pdf

[51] SDG&E Advice Letter 1011-E December 10, 1996

embedded 30A circuit breaker[52], for PEV charging "without having to (1) intercept the existing underground service conduit, install a handhole for splicing, and extend wiring to a new meter socket…[cost savings to the customer approximated at $700-1000]…"(2) have the customer replace the existing single socket service equipment with dual socket service equipment" [53]…[cost savings to the customer approximated at $1500]. However, this metering arrangement increases the customers total service capacity and may require service wire and transformer upgrade.

Some existing residential EV rates require only one meter

As shown in Table 2, SCE's TOU-D-TEV, PG&E's E-9a, and SDG&E's EV-TOU2 require only one meter, and are referred to as "whole-house rates". Only SCE and PG&E have a monthly meter charge for their one-meter arrangements. SCE's TOU-D-TEV offers a PTR option and SDG&E's EV-TOU2 offers a net energy billing provision for those customers who own and operate a solar or wind generating facility.

As discussed below in the section entitled Special Constraints & Considerations, if a residential customer is on a one meter whole-house arrangement then there is currently no differentiation between PEV load and non-PEV load. Currently, PG&E offers a one meter whole-house mandatory and tiered TOU-E9a rate (with 5 tiers within each TOU period), SCE offers a one meter optional and tiered TOU-D-TEV rate (with 2 tiers within each TOU period) and SDG&E offers a one meter optional and non-tiered EV-TOU2 rate. PG&E and SCE offer one meter tiered rates that are subject to AB 1X constraints (see Section 4.4.1 below), while SDG&E's non-tiered rates have no such limitation.

Residential Rates are Primarily Volumetric

The utilities' existing residential PEV rates are primarily volumetric (e.g. the customer is charging on a $ per kW-hr basis). Rates can alternatively be designed to include fixed charges. Fixed charges might do a better job than volumetric charges at aligning PEV rates with the cost implications of charging. For example, an on-peak demand charge could capture the potential distribution cost impact of charging a vehicle on-peak. However, as previously stated, typically demand charges only apply to non-residential customers.

4.2.2 EXISTING COMMERCIAL RATES

A significant issue in this proceeding is essentially, how to encourage parties to install, operate and maintain public charging infrastructure, and still compel the PEV owner to respond to price signals that reflect the true cost, economic and carbon-based, of energy.

Currently SCE offers rate options TOU-EV-3 and TOU-EV-4 for small and medium size commercial customers, respectively. For example, if a commercial customer located in the SCE territory that chooses to provide PEV charging services would opt-into TOU-EV-4 (if demand is expected to exceed 500kW annually) and pay energy, customer and demand charges. The on-peak time period is from

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[52] In accordance with the National Electric Code (NEC), all residential PEV charging requires 40A, a 2-pole breaker and a dedicated circuit

[53] Ibid

noon to 9pm and the off-peak time period consists of all other hours. The summer baseline on-to-off peak rate ratio is less than 2:1.

In response to question 25[54], the Environmental Coalition inquired, "whether, if the above entities are not required to pass through electricity rates to PEV owners, how load management and off-peak charging could still be encouraged at commercial, industrial, and public charging facilities. We are concerned that if PEV owners do not receive an adequate price signal, there will be no incentive to charge during off-peak hours instead of on-peak." In response to question 26[55], SDG&E and DRA both call for distribution demand charges (or additional capacity charges).

Additionally, it is foreseeable that if commercial PEV rates do not align with residential PEV rates, PEV owners may be inclined to arbitrage between charging facilities (meaning charge at whichever location has the lowest price, regardless of time of day), and thereby distort desired charging behavior. If significant, this arbitrage could also contribute to overuse of public fast chargers, perhaps over-inflating the need for more expensive infrastructure and creating additional stress on the grid.

Phase 1 of this OIR made the determination that electric vehicle charging facilities are not utilities, but are generally retail customers of utilities. The Commission's ability to influence the charging of those to whom electric vehicle charging facilities provide a service may therefore be limited to the rates and terms of service provided to the charging facility. The Phase 1 decision concluded that in the long term the station host may have an economic incentive to pass through the electricity price to the PEV owner. The portion of the price signal passed through to the PEV owner is, however, dependent upon the price elasticity of consumer demand. If the assumption is that PEV charging demand will be price inelastic on-peak, the electric vehicle charging provider will be able to pass on most, if not all, of the burden to the consumer at a higher price without losing too much in the way of sales. However, if public charging providers compete based on price, the signal may not be fully passed through to the PEV owner. This is an issue of significant concern when establishing new PEV commercial rates.

To reiterate, existing commercial rates are applicable to customers who offer charging as a benefit of employment, fleet charging (private) or patronage (public) charging. **Those commercial rates that are specific to public charging are applicable to charging stations that are accessible to the public and provided by either a municipality or private entity. A balance must be reached between providing electric vehicle charging providers with an incentive to install, operate and maintain charging infrastructure, on the one hand, and maintaining grid reliability and minimizing utility infrastructure upgrade costs, on the other.**

A/C Cycling Smart Charging Analogue

Onboard rectifying capabilities in certain PEVs coming to market in late 2010 and early 2011 limit wattage to the battery to between 3.3 - 6.6 kW, although offboard DC facilities can supply a higher wattage. Residential central air conditioning systems typically range from 1 to 5 tons (3 to 20 kW) [56]

[54] 25. What rates should apply to customers charging their PHEVs or BEVs at commercial, industrial, and public charging facilities that are in the same service territory as their home utility?

[55] 26. What rates should apply to third-party operators of commercial charging facilities? Should the Commission establish new rates for commercial charging facilities taking into account the costs and benefits created by these entities?

[56] http://physics.nist.gov/Pubs/SP811/appenB9.html

in capacity. Due to a similar power requirement range for PEV charging at Level 2 (e.g. 240V, 30A-80A) and the demand required to start certain air conditioning units (e.g. the A/C locked rotor amp), it may be useful to examine existing A/C cycling incentives.

This demand comparison may not be entirely valid as A/C is only instantaneous and not continuous like PEV charging, but nonetheless worthy of consideration. PG&E has a commercial and residential smart A/C program rate, E-CSAC and E-RSAC, respectively. Both schedules provide the customers with an option to supplement electric service provided by participating in a voluntary demand response program where PG&E installs a device, free of charge, at the customer's premise that can temporarily disengage the customer's A/C unit, during summer peak periods, in exchange for a one-time financial incentive of up to $100.00. Additionally, SCE offers an automatic power shift (D-APS) rate schedule under its Summer Discount Program that allows SCE to disconnect service through automatic control devices. The customer's bill is reduced by a credit of between $0.05 and $0.18 per ton of A/C for 50-100% of cycling, respectively. In both instances the utility owns and operates the device.

In summary, current residential and commercial electric vehicle rates and air conditioning (A/C) incentives serve as a starting point. Whether existing rates can scale to accommodate increased participation is a topic discussed further in Section 4.4.1.

4.3 OPTION TO CREATE A NEW PEV CUSTOMER CLASS

There exist four broad classes of customer: Residential, Commercial, Industrial (typically referenced as C&I) and Agricultural. Each is divided into sub classes as necessary (e.g. special-use classes that necessitate special rates on the grounds that the services they receive have peculiar cost factors).

In response to question 29[57], posed in the August 20, 2009 Rulemaking (R.) 09-08-009, TURN contemplates the possibility of creating a new electric vehicle rate class that is tailored to PEV cost of service.[58] **Should a new PEV rate class be created, the Environmental Coalition believes new rates that fully reflect the costs and benefits of PEVs should be established, and TURN asserts that any immediate customer-specific costs should be assigned to the specific customer, while any systemic costs unique to PEV charging (e.g. billing systems) should be borne by the specific PEV rate class.** Regardless, most parties agreed that a new rate should include existing rate component costs and should reflect the marginal cost of service.

4.4 SPECIAL CONSTRAINTS & CONSIDERATIONS

In addition to the different types of rates there are other constraints and considerations that must be examined when determining how in which to structure future PEV rates.

[57] 29. Should the electric vehicle rate structure be designed to align rates with the system costs and benefits of PHEVs and BEVs, and if so, how? Should the Commission assign additional costs and benefits attributable to PHEVs and BEVs to specified electric vehicle rate classes or socialize the costs and benefits attributable to PHEVs and BEVs to all customer classes? Should the PHEV and BEV rate classes bear existing rate component costs?

[58] TURN, October 5, 2009 Comments, p.10

4.4.1 SENATE BILL (SB) 695

Assembly Bill (AB) 1X was enacted on February 1, 2001. AB 1X added Section 80110 to the Water Code, providing in relevant part: "In no case shall the commission increase the electricity charges for residential customers for existing baseline quantities or usage by those customers of up to 130 percent of existing baseline quantities, until such time as the department has recovered the costs of power it has procured…the right of retail end use customers [ ] to acquire service from other providers shall be suspended until the department no longer supplies power hereunder."[59] This amounted to a rate freeze for residential Tiers 1 and 2 and a suspension of direct access, until the California Department of Water Resources, which had procured power on behalf of the IOUs following the energy crisis, no longer supplies said power, and has fully recovered the costs of doing so.

However, SB 695, as chaptered October 2009, "delete[d] the prohibition that the commission not increase the electricity charges in effect on February 1, 2001, for residential customers for existing baseline quantities or usage by those customers of up to 130% of then existing baseline quantities [and authorized] the commission to increase the rates charged residential customers for electricity usage up to 130% of the baseline quantities by the annual percentage change in the Consumer Price Index from the prior year plus 1%, but not less than 3% and not more than 5% per year."[60] Therefore Tiers 1 and 2 are now allowed to increase annually as provided in SB 695.

In addition, SB 695 added Section 745 which prohibits mandatory or default time-variant pricing, with or without bill protection for residential customers prior to January 1, 2013. SB 695 states that "Time-variant pricing" includes time-of-use rates, critical peak pricing, and real-time pricing, but does not include programs that provide customers with discounts from standard tariff rates as an incentive to reduce consumption at certain times, including peak time rebates."[61]

A default rate is one in which a customer is automatically enrolled unless the customer affirmatively chooses not to be on the rate. Default rates are also referred to as "opt-out" rates. In party responses to questions 24[62] and 25[63], SCE stated that default rates were unnecessary, DRA and SMUD favored opt-in time variant rates but PG&E, SDG&E and the Environmental Coalition all favored a default time variant rate. Though default time variant rates may be statutorily constrained for residential customers until 2013, a default commercial dynamic rate will be established for PG&E in November 2011 per D.10-02-032, as early as January 2012 for SCE (A.08-03-002 / A.07-12-020) if the customer has received a smart meter, and likely in the third quarter of 2013 for SDG&E (A.10-07-009).

Currently, under a non-time-variant or TOU rate, the monthly electric usage of a residential customer with a one meter whole-house arrangement could be pushed into a higher tier if he/she were to

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[59] http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0001-0050/abx1_1_bill_20010201_chaptered.pdf

[60] http://www.leginfo.ca.gov/pub/09-10/bill/sen/sb_0651-0700/sb_695_bill_20091011_chaptered.pdf

[61] Ibid

[62] 24. Should the Commission authorize a default time variant electric vehicle rate applicable to all residential electric vehicle tariff customers? What changes, if any, to the rate protection provisions of AB-1X30 are needed to authorize a default time variant electric vehicle rate applicable to residential customers?

[63] 25. What rates should apply to customers charging their PHEVs or BEVs at commercial, industrial, and public charging facilities that are in the same service territory as their home utility?

purchase a PEV and chose to charge at his/her residence. All of the customer's usage would be charged the same rate. A smart meter cannot, at present, measure and communicate a subload, in other words, differentiate between PEV and non-PEV usage. In the future, meters may have the capacity to communicate a subload amount to the utility. In the interim there are three options, which is a topic of the "Roles" Paper:

- Single (whole-house): Estimate the PEV or non-PEV usage and subtract that baseline from total usage
- Submeter: Install a separate meter in series, as a submeter, or
- Separate: Install a separate meter in parallel, as another revenue grade meter, to track the additional vehicle usage

Phase 2 of R. 09-08-009 is dedicated to developing rate design principles that allow PEV owners to clearly understand the benefit of opting for a rate that is designed to incent customers to charge when system capacity and environmental benefits are maximized. One issue to consider in developing a time variant rate without an inverted tier pricing scheme is that implementing a whole-house PEV rate option without a baseline provision could allow existing large-use upper-tier customers to migrate to non-tiered rates, which raises cost recovery concerns. The question of whether existing PEV rates are scalable, meaning successful in recovering allowable revenues given increased rate migration, is one that must be considered if participation increases dramatically in coming years.

4.4.2 NON-BYPASSABLE CHARGES REPRESENT A TOU OFF-PEAK PRICE FLOOR

In response to question 30[64], while most parties agreed that the PEV rate should reflect the marginal cost of service, SCE and DRA emphasize that the PEV rate should also reflect all non-bypassable public purpose program costs. There exist four non-bypassable charges (NBC):

- Nuclear decommissioning (ND),
- Public purpose programs (PPP), which includes CARE
- Reliability services (RS), and
- the DWR bond charge.

These charges were deemed non-bypassable per kWh charges by Decision (D.) 03-04-030/ (D.) 04-12-048. This represents not a statutory constraint so much as a TOU off-peak price floor guideline, based on traditional ratemaking principles, in that the off-peak rate must not fall below the sum of the marginal energy cost (MEC) plus non-bypassables. It may be the off-peak marginal energy cost is negative, perhaps due to an over-supply of wind, in which case the price floor would consist only of NBCs. The magnitude of the ratio of the on-peak to off-peak TOU rate is dependent upon this price floor. The magnitude of the ratio may be limited not only by the off-peak rate but also by the on-peak rate as there exists a possibility that a higher rate of opt-out (meaning voluntarily migrate to another rate), may occur relative to other rate schedules.

In summary, there are a number of considerations and constraints that must be examined when determining how to structure future PEV rates. **PEV rate design guidance may draw from past and present utility experiences with PEV residential rates, existing peak time rebates (PTR), existing**

[64] 30. Should the electric vehicle rates reflect the marginal cost of service, particularly for off-peak electricity charging and, if so, how?

direct load management by time clocks or switches, and A/C demand response schedules. Customer rebates and /or rates reflecting a rebate, penalty or throttle-back options for on-peak charging at commercial charging facilities may be required in order to minimize system upgrade costs and mitigate grid instability. Customer incentives to allow the utility to offer direct charging management services will be considered in the fourth workshop in Phase 2 related to Smart Grid/Alternative-Fueled Vehicle rulemaking overlap issues. Ultimately a number of rate attributes will likely need to be utilized in combination in order to predictably and consistently shift load.

SECTION 5: PEV ADOPTION STRATEGIES

This section considers various strategies related to increasing PEV adoption rates that are related, directly or indirectly, to the ratemaking process.

5.1 BEHAVIOR AND EDUCATION

In addition to rate attributes, customer perception is an important aspect of effective rate design. There exists a great deal of uncertainty around actual charging behavior. Ratepayer elasticity of demand varies. Ratepayer understanding of rates varies. Price signals may not be sufficient in shifting load off-peak, particularly where a public charging service provider chooses to offer a price discount to gain some other business or profit advantage with the user, such as a retailer offering (free or discount) charging in its parking facility as an incentive to capture retail customers for other services or goods. Ratepayers who actively manage their PEV charging may do so without regard for the underlying electricity charging price.

Additionally, the preferred charging approach for many customers without access to residential charging is undefined. Public or privately-offered DC charging offers a potential solution for customers without access to residential charging, or for battery electric vehicle drivers that need to extend vehicle range in 30 minutes. Distribution system impacts may be greater at these facilities due to higher demand and voltages, although some facilities may mitigate impact issues (and potential higher rates) through co-location of stationary storage options (including battery exchanging) to arbitrage time differentiated rates. Utility notice for "fast charge" DC facilities or Level 3 AC facilities is paramount. A methodology to account for greater grid impacts due to fast charge facilities may be warranted, but further study of distinct grid impacts and usage (relative to public Level 1 and Level 2 facilities) is required.

As stated above, off-peak residential charging offers important grid and environmental advantages, and it is reasonable that the Commission would approve time-favorable rates that support this charging behavior objective. However, on-peak charging still displaces petroleum and its associated emissions, and many potential PEV purchasers may not have access to residential charging and may be forced to charge at workplaces or shopping destinations.

The extent to which a customer will compare his/her residential on-peak PEV charging rate to the residential off-peak charging rate, to the public on-peak charging rate, or to the gasoline equivalent rate is not well understood. **Customer usage for PEV electricity fuel will increase the overall customer electricity bill, while decreasing the overall customer transportation fuel cost (e.g. displacing gasoline fuel costs).**[65] The California Energy Commission found that the average California residential consumption ranges between 400 kilowatt-hours (kWh) to 800 kWh per month.[66] Certain PEVs expected to come to market in late 2010, early 2011, will contain batteries in the 16-24 kWh capacity range. Daily PEV kWh usage will depend on driving behaviors and PEV efficiency

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[65] Idaho National Labs, "Comparing Energy Costs per Mile for electric and gasoline-fueled vehicles," http://avt.inel.gov/pdf/fsev/costs.pdf

[66] Average customer usage depends in part on diverse air conditioning cooling load requirements that are different for particular climate zones.

(mi/kWh). If a PEV with an efficiency of 4mi/kWh drives 40 miles/day in electric range, the customer usage dedicated to the PEV may be 10 kWh per night. Assuming the residential customer now uses 15 kWh/24-hour cycle (450 kWh per month), and assuming the customer demands 10 kWh per night for charging to drive 40 miles/day in electric mode (Assuming 1200 monthly electric vehicle miles traveled, and monthly energy usage increase is assumed to be 300kWh on a 30 day cycle), this consumption may increase their existing daily usage by 67%. Assuming the customer pays $0.168/kWh (SDG&E EV-TOU-2 summer off-peak rate), the customer increase in fueling cost would be at an increased cost of $50.40/month for usage. Assuming the gas price is $3.038/gallon (DOE EIA weekly California retail gasoline prices, regular grade, 8/30/2010), and a conventional vehicle fuel efficiency is 22 mi/gallon, this household may have been spending $165.71 /month on 18.18 gallons to drive 1200 miles/month using gasoline no longer needed. **While electricity usage is expected to increase for PEV customers, fuel-switching is a globally more efficient energy use (e.g. from the inefficient internal combustion engine to the more efficient conventional power station and renewable generators to the electric PEV motor).**[67] There is a need for more investigation into customer charging behavior as a factor in developing a cohesive customer strategy. Energy Division recommends that this proceeding seek to encourage least cost behaviors.

Opt-in rates (and PEV market commercialization generally) require education and outreach. At the core is an understanding of which behavioral levers, from prices and enabling technologies to feedback and social norms, are most effective at inducing demand responses and shifting load. If customers become accustomed to rates it may prove difficult to overcome rate history inertia. It is therefore important to provide the customer with the knowledge of why one's rate might be changing.

Though electrification may be gradual, policies adopted today will certainly influence future customer expectations. Should public DC Fast charging stations outpace residential charging installations, PEV owners may become reliant upon more expensive infrastructure. Though non-residential distribution systems may require less costly infrastructure upgrades than residential neighborhoods, the degree to which public DC Fast charging will require a system upgrade depends on whether or not the chosen premise is currently a small, medium or large commercial or industrial customer.

5.2 COHESIVE CUSTOMER EDUCATION STRATEGY

Meaningful and effective load shifting will rely upon many factors. The strategic elements that should be considered are the following:

1) Time-of-use price signals
2) Ongoing behavioral research
3) Additional rate attributes:
    a. "Smart"charging incentives
    b. "Any Time"charging penalties
4) Direct cost and benefit assignment, wherever possible
5) Enabling technologies
6) Education and outreach[68]

[67] Mui, Simon. July 15, 2009. "CPUC Smart Grid Rulemaking. Workshop 4 –PEV integration issues." http://www.cpuc.ca.gov/NR/rdonlyres/6805C484-2439-495A-82DF-B7BF8F0853F8/0/SimonMuiNRDC.pdf

[68] 39. What entities and programs best facilitate customer outreach and education regarding convenient and timely EVSE installation options and customer tariff education to ensure awareness of off-peak versus on-peak charging costs?

In response to question 39[69], parties stated that the education and outreach function could be shouldered by utilities, third party service providers, or local government entities but regardless of which party adopts this role, promoting awareness in the form of tariff education, online tools, GHG impact data and battery recycling programs is critical to the successful realization of PEV benefits.

5.3 INTER-UTILITY BILLING

In response to question 27[70], posed in the August 20, 2009 Rulemaking (R.) 09-08-009, some parties suggested a single billing procedure that would link all PEV billing to a customer's home utility account. Such a system would simplify charging at work and at home, but would require a 'clearinghouse' system to settle billing between locations and utility territories. Settling sales between utilities would likely require complex rules governing the cost to users and the compensation to utilities. Ultimately, inter-utility arrangements require 'vehicle-based' billing, which is a function of the PEV's telematics. The advantages and drawbacks to roaming arrangements merit further evaluation and investigation. **Bill reconciliation represents a nascent market and therefore the Commission may not wish to foreclose any options at this time.**

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[69] Ibid

[70] 27. How should a customer pay when charging a PHEV or BEV in another utility's service territory? Please evaluate options set forth below, or suggest alternative approaches: a. A customer pays a posted price for electricity to a specific electric charging provider at the time of the transaction, similar to how gasoline is purchased. b. The second utility bills the customer's home utility and the home utility adds the electric vehicle electricity cost to the customers' energy bill. A third-party clearing house could facilitate these transactions. d. A customer has a relationship with a third party charging provider and pays that third party wherever the customer charges. e. A customer has a choice of all or some of the above options.

SECTION 6: CONCLUSIONS, RECOMMENDATIONS, AND QUESTIONS

6.1 CONCLUSIONS

Parties agreed that system impacts from electric vehicles would be minimal in the short-run, though likely more significant later.

- Parties identified increasing peak load and reliability impacts as potential drawbacks to electric vehicle proliferation, as well as potential distribution system impacts associated with coincident, geographically clustered PEV charging, particularly for residential circuits.

- Parties also agreed that shifting load off-peak was most desirable for numerous reasons including: balancing daily load, increasing demand for renewables, decreasing GHG emissions and reducing criteria pollutants. The economic benefits realized from PEV use are manifest in the spreading of fixed costs over a greater volume of off-peak kWhs. There are also operational efficiencies realized through increased asset utilization which includes, avoided shutdown or ramping, minimized cost for new peak generation, levelized distribution, increased reliance on renewable generation and the associated reduction in GHG.

PEV residential rates:

- Existing IOU electric vehicle rates differ with respect to on-peak and off-peak time periods and ratios, optionality, tiering, and meter charge.

PEV non-residential rate innovation must consider the following:

- Providing an adequate price signal to PEV charging provider customers is essential to address costs that PEVs cause on the electric grid
- Arbitrage may occur between residential and commercial rates and could contribute to overuse of, or reliance on, public charging
- If charging providers compete based on price, perhaps in combination with other marketing mechanisms and collateral business opportunities, the electricity signal may not be passed-thru to the charging provider's customers

6.2 ENERGY DIVISION RECOMMENDATIONS

1) The Commission should consider whether existing electric Rules do, or should, govern PEV customer charging installations and/or potential upgrades to the distribution system.

2) The Commission should consider the appropriate review path by which IOUs seek recovery of PEV-related expenditures. Parties should establish a framework for PEV cost/ benefit

determination if recovery for capacity upgrades will take place outside the GRC process. This may require each IOU to perform a distribution system impact analysis to inform capacity planning.

3) IOUs should be required to track the cost of distribution system upgrades required by non-residential and residential customers installing PEV charging facilities.

   The Commission should consider which cost recovery mechanism shall be implemented, if any. This requires differentiating between PEV load and any new load as well as establishing criteria for, and a mechanism for tracking identified costs.

4) PEV rate design should serve to simplify attributes (e.g. on-peak, off-peak, partial peak and super-off peak TOU time periods, tiering and multiple metering arrangements). Additionally, PEV rate design requires further exploration of the effectiveness of greater TOU on-to-off peak ratios in combination with enabling technologies and direct charge management.

5) PEV rates should:
   a. Respect principles of fairness in allocation
   b. Be practical to implement
   c. Be easy to understand and promote stability of bills and remittances
   d. Avoid subsidy from non-PEV owning ratepayers in order to ensure equity and conform to statutory constraints
   e. Draw upon past and present PEV residential rates, existing direct load management time clocks or switches, and A/C demand response schedules,
      i. Customer rebates and /or rates reflecting a rebate, penalty or demand reduction options for on-peak charging at commercial charging facilities may be required in order to minimize system upgrade costs and mitigate grid instability.

6) It is not well understood to what extent a customer may compare his/her residential on-peak PEV charging rate to the residential off-peak charging rate, or to the public on-peak charging rate or to the gasoline equivalent rate. This is a matter deserving of much more observation and study.

7) Developing a comprehensive customer education strategy that includes rate design, education and outreach should be implemented as ultimately a number of rate attributes will likely need to be utilized in combination in order to predictably and consistently shift load.

8) Parties should explore the pros and cons of creating a new PEV rate class for non-residential charging.

6.3 QUESTIONS

RULES

1) Do current electric Rules imply inclusion of PEVs or should PEV inclusion be made explicit?

2) Per Rules 2, 15 and 16 should PEV load continue to be designated as 'new load' or should distribution system upgrades be treated as 'special facilities'? If PEV load continues to be designated as 'new load' would the current allowance formula apply?

3) Per Rule 15, should there be a separate allowance for PEVs or should the existing allowance reconsider the net distribution revenue? And should line extensions for Level 2 service versus that for DC fast charging service be differentiated and made explicit through revision to the Rule?

4) Per Rule 18, should existing terms of service apply to submetering MDU PEV charging or should the terms of service be reconsidered?

5) Per Rule 21, if PEVs are considered a distributed energy resource might similar treatment apply regarding interconnection and study fees? Are PEVs NEM-eligible distributed resources?

RATES

6) How long shall the IOUs track PEV-related infrastructure upgrades? Is the early PEV market (eg, 2010-2015) and appropriate time period What mechanism shall be adopted in the interim?

7) How does SB 695 impact PEV residential rate design, if at all?

8) Should PEV residential rates be opt-in, non-tiered rates? Are existing PEV rates scalable, as participation may increase in coming years?

9) Should the Commission consider a separate rate for "Fast Charge" or "Quick charge facilities?" If not, what rate should apply to these facilities? If so, what existing methodology should the Commission consider to develop a separate rate?

10) Should residential BEV rates include fixed demand charges to align the rate with the cost impacts of charging?

11) Have distribution infrastructure costs always been spread uniformly across all ratepayers? To the extent that ratepayers in coastal areas have historically contributed to the more robust distribution systems that exist inland, should greater coastal PEV integration costs be addressed similarly?

12) For inter-utility rates, what principles shall be needed to ensure customer choice and simplicity?

APPENDIX

Table 6

		Residential	Opt-In	Tiered	Meters
SCE	TOU-EV- 1	y	y	n	2
	TOU-EV-3 (<20kW)	n	y	n	2
	TOU-EV-4 (20 - 500kW)	n	y	n	2
	TOU-D-TEV	y	y	y	1
PG&E	E6 (TOU) non-EV	y	n	y	1
	E7 (TOU) non-EV (closed)	y	n	y	1
	E-9a (TOU)	y	n	y	1
	E-9b (TOU)	y	n	y	2
	E-9c (TOU) (closed)	y	n	y	1
	E-9d (TOU) (closed)	y	n	y	2
SDG&E	EV-TOU (seasonal)	y	y	n	2
	EV-TOU-2 (seasonal)	y	y	n	1
	EV-TOU-3	y	y	n	2

Table 7a

		Off-Peak Winter	Off-Peak Summer	Partial Peak Summer	Partial Peak Winter
SCE	TOU-EV- 1	all other	all other		
	TOU-EV-3 (<20kW)	all other	all other		
	TOU-EV-4 (20 - 500kW)				
	TOU-D-TEV	all other	all other		
PG&E	E6 (TOU) non-EV	all other	all other	10 -1pm & 7 - 9pm M-F; 5 - 8pm SS	5 - 8pm M-F
	E7 (TOU) non-EV (closed)	all other	all other		
	E-9a (TOU)	all other	all other	7 - 2pm & 9 - Mid M-F; 5 -9pm SS	7am - Mid M-F; 5 - 9pm SS
	E-9b (TOU)	all other	all other	7 - 2pm & 9 - Mid M-F; 5 -9pm SS	7am - Mid M-F; 5 - 9pm SS
	E-9c (TOU) (closed)	Mid - 7am M-F; 5 - 9pm SS	Mid - 7am M-F; 5 - 9pm SS	7 - 2pm & 9 - Mid M-F; 5 -9pm SS	7am - Mid M-F; 5 - 9pm SS
	E-9d (TOU) (closed)	Mid - 7am M-F; 5 - 9pm SS	Mid - 7am M-F; 5 - 9pm SS	7 - 2pm & 9 - Mid M-F; 5 -9pm SS	7am - Mid M-F; 5 - 9pm SS
SDG&E	EV-TOU (seasonal)	all other	all other		
	EV-TOU-2 (seasonal)	all other	all other		
	EV-TOU-3	all other	all other		

Table 7b

		On-Peak Summer	On-Peak Winter	Super Off-Peak Summer	Super Off-Peak Winter
SCE	TOU-EV- 1	Noon - 9pm	Noon - 9pm		
	TOU-EV-3 (<20kW)	Noon - 9pm	Noon - 9pm		
	TOU-EV-4 (20 - 500kW)				
	TOU-D-TEV	10 - 6pm	10 - 6pm	Mid - 6am	Mid - 6am
PG&E	E6 (TOU) non-EV	1 -7pm M-F			
	E7 (TOU) non-EV (closed)	Noon - 6pm M-F	Noon - 6pm M-F		
	E-9a (TOU)	2 - 9pm M-F			
	E-9b (TOU)	2 - 9pm M-F			
	E-9c (TOU) (closed)	2 - 9pm M-F			
	E-9d (TOU) (closed)	2 - 9pm M-F			
SDG&E	EV-TOU (seasonal)	Noon - 8pm	Noon - 8pm	Mid - 5am	Mid - 5am
	EV-TOU-2 (seasonal)	Noon - 6pm	Noon - 6pm	Mid - 5am	Mid - 5am
	EV-TOU-3	Noon - 8pm	Noon - 8pm	Mid - 5am	Mid - 5am

(END OF REVENUE ALLOCATION AND RATE DESIGN: FACILITATING PLUG-IN ELECTRIC VEHICLE INTEGRATION- DECEMBER 2010 (REVISED) VERSION)

Energy Division Staff Workshop Report
Revenue Allocation and Rate Design workshops
September 29 and 30, 2010
California Public Utilities Commission

Introduction

On September 29, 2010 and September 30, 2010, the California Public Utilities Commission (Commission) held two workshops related to "Revenue Allocation and Rate Design" in the context of the Commission's Alternative-Fueled Vehicle Rulemaking (R.09-08-009).

Topics and panelists for the workshops were determined based on stakeholder comments on the Energy Division workshop issues paper "Revenue Allocation and Rate Design: Facilitating Plug-in Electric Vehicle Integration" issued September 10, 2010 and the purpose of the workshops was to build consensus (and identify any areas of disagreement) around these select issues.

This Energy Division Staff Workshop Report (Report) summarizes party positions and issues addressed at the workshops. The Report is being provided to the proceeding service's list and will be subsequently entered into the record toward the end of 2010 (October 27, 2010 Administrative Law Judge Ruling at p. 7).

Day 1 - PEV Revenue Allocation (September 29, 2010)

Day 1 of the workshop focused on the feasibility of developing a framework for a PEV cost/benefit determination as driven by tariff electric rule-based cost assignment. Revenue allocation describes a more specific process in which marginal costs are multiplied by a billing determinant and then scaled via an "equal percentage of marginal cost" (EPMC) factor to arrive at total allowable revenues. In the short-term, tariff electric rules assign shared resource costs. Longer term, revenue allocation at the class level will account for cost causation.

1. PEV-related Cost and Benefit Determination

Panelists:
Simon Mui, Natural Resources Defense Council
Liang Huang , PG&E
Russ Garwacki, SCE

This panel addressed questions related to IOU cost recovery review paths, the need for a PEV-related cost/benefit determination, and the appropriate mechanism and duration for tracking IOU PEV-related expenditures.

Party Positions

At the workshop, parties identified multiple cost and benefit spheres in the PEV context whose calculation and assignment may fall within multiple jurisdictions (e.g., federal, state, and local). Some benefits, such as petroleum consumption reduction and GHG emissions reduction, are global. Parties were reminded that the Commission has jurisdiction over the identification and allocation of cost and benefits as they pertain to PEV rates. Rates represent one factor in the PEV owner's total cost (or payback) calculation, in addition to petroleum prices, battery manufacturing costs, depreciation, and the ownership period.

Given the complexities involved, the calculation of costs and benefits will be the subject of further examination as PEV market penetration increases. The majority of parties in written comments and in verbal comments made at the workshop agreed that in the short term (which parties quantified as 2010-2015), separately tracking and assigning PEV-related costs and benefits would be problematic (including from a power systems engineering perspective) and could unfairly penalize PEV load.

However, parties argued cost and benefit tracking is not unprecedented. Parties noted the Commission's Advanced Metering Infrastructure proceeding (D.06-07-027) established a balancing account to track the costs and benefits associated with metering. However, there was general consensus around the inadequacy of data needed to inform a cost/benefit determination specific to PEV impacts on the electricity grid.

IOUs stated non-residential distribution upgrades are currently tracked. If residential distribution upgrades, the result of PEV loads, are not to be tracked, then costs will be shared amongst all ratepayers in the short-term. Parties identified time and location-specific avoided cost methodologies in the demand response context from which parties might draw insight.

There was also general consensus that existing rates and cost recovery mechanisms are adequate for the short-term PEV market (e.g., 2010-2015), though in the time period between triennial General Rate Cases (GRC), IOUs have the option to file applications for off-cycle costs. It is expected that in the short-term that costs will be related to "back-office" information technology upgrades related to EVSE installations with communication nodes and switches and, to a lesser extent, capital improvements. IOUs were in agreement that these costs associated with third–party electric vehicle service provider integration should be borne by the third party and not ratepayers.

Longer-term, parties asserted a need to revisit how PU Code 740.8 defines 'ratepayer interests' in the context of rate design of PEVs. But in the short-term, utility efforts should be focused on piloting PEV load studies, developing technologies, programs and protocols that will encourage beneficial charging behavior and inform a cost/benefit framework.

Parties requested that the Phase 2 decision in this proceeding should make a determination as the appropriate time period for non-tracking and tracking of costs and benefits. This determination may not be time-based, but rather dependent upon PEV market penetration, other agency mandates (e.g. ARB's LCFS), number of customer voltage drop complaints, and other determinants.

Staff Observations

Staff noted that the practice of socializing[1] costs while PEV market penetration is low is acceptable to some parties due to the difficulty in differentiating load for PEVs from other demands on the system. Many parties were generally not in favor of developing statistical methods as a tool to estimate costs and benefits. In the mid-term a cost-benefit framework may need to be developed. Some parties referenced the framework given in the paper authored by Bob Levin of DRA as a starting point.

Regarding the suggestion that time and location-specific demand response avoided cost methodologies might provide guidance in the PEV cost/benefit context, staff observes that both quantitative and qualitative factors would need to be considered in determining the applicability of these methodologies.

Findings

In the short-term, Staff believes existing rates and cost recovery mechanisms are adequate. Staff believes IOU efforts (and cost recovery) should focus on piloting PEV studies, developing enabling technologies, programs and protocols that will encourage beneficial charging behavior. Costs associated with third–party electric vehicle service provider (EVSP) integration should seek guidance from existing Demand Response (DR) aggregator contracts. Additionally, Staff believes it is important to resolve which party will shoulder third-party system integration costs. Staff recommends that a timeline be created that serves to define short-term and long-term when determining when PEV-related costs should be separately tracked.

In the long-term, Staff recommends developing a PEV cost/benefit framework and believes it is important to revisit the PU Code 740.8 definition of "ratepayer interests" as it pertains to PEV-related benefits.

<u>2. Tariff Electric Rules</u>

Panelists:
Bob Levin, DRA
Matt Imel, PG&E
Herb Moses, SCE

This panel addressed questions related to the treatment of PEV load as "new load," safety considerations due to increased PEV adoption and the need to address revising tariff rules with respect to allowances, line extensions, submetering, distributed energy and ESPs.

Party Positions

If the distribution system is sized to peak load and that load is exceeded then that load is designated "new load," in that the demand on the system exceeds the level for which it was designed and for which costs have been assigned. Parties noted the definition of "new load" may

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[1] See Question 29, posed in the August 20, 2009 Rulemaking (R.) 09-08-009,

need to be clarified to differentiate between upgrades to existing dwellings versus new dwellings. Parties noted that distribution upgrades for existing dwellings are sometimes categorized as 'betterment,' the costs of which are typically shared by all ratepayers. Also, some parties questioned the classification given that "new load" is permanent and PEVs are mobile.

PEV load is currently treated as new load and eligible for the standard allowance. Parties observed that if PEV load continues to be treated as "new load," then additional discussion may be needed regarding how the allowance[2] is calculated and applied. Currently the allowance for residential customers is fixed and based on average costs. Parties stated that in the long term, Tariff Electric Rule 16 - Service Extensions, allowance may need to be revised to be more granular and specific to the end-use load. As an alternative to the allowance, DRA proposed a distribution infrastructure charge which would apportion the cost of upgrading facilities to the PEV owner in the form of a monthly charge over the life of the capital deployed. This facilities charge is not the same as a demand charge. Parties asserted that there is no typical secondary distribution arrangement (e.g., as each distribution facility and circuit is different) so drawing this distinction may be difficult and unwarranted in the short-term. Parties raised the issue of accidental inequity whereby one customer by nature of the sequencing of PEVs added to the circuit, may introduce impacts, though similar on an individual basis, that have very different repercussions in aggregate. IOUs stressed the importance of early utility notification of the PEV location as a cost and installation time mitigating strategy.

Parties were in agreement that a Rule defining an EVSP is warranted in the short-term for purposes of rate schedule qualification. SCE classifies EVSPs as commercial entities and had not contemplated EVSPs in the residential context. SCE suggested that Tariff Electric Rule 22 - Direct Access, be revised to include EVSPs that are also ESPs. IOUs stated that allowances would not apply to residential EVSPs, even to those who aggregate load, because the allowance represents the upgrade for a specific service point to the account holder. IOUs asserted that EVSPs that operate charging stations would likely be classified as commercial and industrial (C&I) customers and the non-residential allowance formula would therefore be applied.

Parties also stated that Tariff Electric Rule 18 - Supply to Separate Premises and Submetering of Electric Energy, may need to be readdressed in the mid- to long term. Parties diverged on what specifically needed to be revised, but some parties put forth the following: that submetering of load by the customer or third party is currently not authorized, that language regarding furnishing, ownership and testing of submeters need be re-examined and that for master metered customers there should be a separation of rent from electricity.

Parties view Tariff Electric Rule 21 - Generating Facility Interconnections, issues as a mid- to longer term issue. PEVs are not at this time NEM-eligible because it is not certain how much, if any, energy would be exported and how much, if any, would go toward PEV charging.

PG&E does not favor revision of Rules and would prefer to monitor, a term which as clarified by Coulomb, is not the same as preserving the status quo. Additionally, as data is currently

[2] Revenue Allocation and Rate Design: Facilitating Plug-in Electric Vehicle Integration, p. 22, R.09-08-009, September 10, 2010 Ruling

inadequate to perform a cost/benefit determination it may prove beneficial to establish a repository for parties to share data in the short-term. Parties requested information sharing.

Staff Observations

At the workshop, there was general agreement that existing Rules and allowances are adequate in the short-term. Staff identified consensus around the need for Rule clarification, but not necessarily revision for PEVs. Currently PEV load is treated as "new load." As "new load" it is eligible for an allowance. The allowance represents prepaid ratebase, and in effect, means that residential distribution system upgrades as a result of PEV load are costs borne by all ratepayers. Staff observed that since "new load" represents an aggregate of load additions over time, the definition must address the frequency or threshold for allowance applicability. Staff believes the challenge going forward will be to navigate between simple versus accurate allocation of costs. Staff gleaned four scenarios worthy of examination, which may be addressed sequentially or alone: (1) maintain and apply existing allowance, (2) change the allowance, (3) create a separate allowance or (4) create a new mechanism altogether (e.g. distribution infrastructure charge). Staff notes that IOUs may need to further examine the line between 'betterment' and distribution upgrades that fall within the scope of Electric Rule 16 - Service Extensions.

Staff supports a Phase 2 decision that directs parties to develop a working EVSP definition that accounts for different types of EVSPs in both the residential and non-residential context. There is also a need to re-evaluate how "new load" is defined in order to appropriately balance applying an allowance to PEV load, which is entirely cost-based, while not yet accounting for the benefits of the "good" PEV load.

Findings

In the short-term, Staff recommends clarifying and monitoring existing tariff electric rules to accommodate EVSPs. This may include an addition to Electric Rule 1 – Definitions, defining the variety of types of EVSPs, inclusion of EVSPs that are also ESPs in Electric Rule 22 - Direct Access, and clarifications regarding EVSP role and vehicle ownership in Electric Rule 18 - Supply to Separate Premises and Submetering of Electric Energy, in tandem with development of sub-metering protocol and sub-metering rate alternative. Staff believes that comprehensive tariff electric rule clarifications should be made simultaneously across all IOUs.

In the long-term, Staff sees the merit in revising Electric Rule 16 – Service Extensions, as it pertains to "new load." It is important to differentiate between "new load" (associated allowance calculation) and broader IOU system betterment. In doing so, Staff recommends addressing the issue of accidental inequity and perhaps a distribution infrastructure or facilities charge.

Day 2 - Rate Design (September 30, 2010)

Day 2 of the workshop addressed the following question: "What are the rate design principles that must be employed in order to shift load, lower emissions, ensure grid reliability, promote adoption and foster competition?"

3. Existing Residential PEV Rates

Panelists:
Barbara Barkovich, Principal, Barkovich & Yap, Inc.
Bob Levin, DRA
Max Baumhefner, NRDC
Bob Hansen, SDG&E

This panel addressed questions related to the adequacy of existing PEV rates, legislative constraints and different rate options that may be utilized to incent shifts in load, namely the differences and implications of implementing a volumetric rate versus a fixed charge rate.

Party Positions

In the long-term, parties generally supported general electric rate reform. Parties expressed concern that PEV rates may become another bolt-on solution to a broken rate structure. Parties stated that SB695 does not allow for mandatory or default time-variant rates until 2013.

Parties gave two reasons why existing PEV rates are inadequate in the long-term. As adoption scales upward more ratepayers will likely migrate from a tiered rate to a TOU rate which may lead to fewer non-PEV owners paying tiered rates that recover legacy costs. Legacy costs may include certain non-bypassable charges and implicit AB1X subsidies. Secondly, if PEV owners are subject to tiered rates or tiered TOU rates then they will be penalized for increasing usage, jeopardizing the fuel cost advantage of a PEV versus a conventional vehicle.

Parties were seemingly in agreement that a whole-house single meter opt-in non-tiered TOU rate would be adequate in the near term and could perhaps be phased out in the long-term. PG&E stated that the E-9 rate would need to be adapted to conform to SB695. Secondly, parties proposed a low cost submetering alternative, so that load might be differentiated.

One party raised concern that a whole-house time variant price signal would be muddled for non-PEV usage. In other words, customers may take advantage of lower off-peak rates instead of curbing consumption via a tiered rate structure. Another party was quick to point out the distinction between conservation and efficiency. A TOU rate might not compel the ratepayer to <u>reduce</u> usage, only to <u>shift</u> usage to another more economically desirable time period. Individual baselines were proposed as a means for segregating tiered non-PEV and TOU PEV usage. Parties remarked, however, that backend IT upgrades to accommodate an individual baseline may take years to implement. At the same time, fuel switching was identified as an energy efficient action so energy conservation may be achieved in that manner as well.

Staff inquired as to whether or not residential demand charges might serve to complement volumetric rates. Parties stated that residential demand charges may not be necessary if distribution capacity upgrades can be fully reflected in TOU rates, though fixed demand charges are a much more efficient tool for recovering demand-related costs. Another party stated that real-time pricing is not effective at passing along capacity value so some consideration must be given to the appropriate time-specific fixed or volumetric charge. Additionally, to the extent that A/C load drives peak consumption, less accurate fixed TOU periods may be sufficient in the absence of distributed energy storage.

With regard to photovoltaic (PV)-PEV integration one party stated that residential customers receive multiple subsidies already for PV install. The purchase of PV reduces consumption of IOU-generated energy, which drops PV-owning ratepayers into lower tiers 1 and 2. Tiers 1 and 2 are subsidized by tiers 3, 4 and 5 due to AB1X rate freeze legislation. In addition, PV-owning ratepayers receive state and federal tax credits.

One panelist stated that customers need to be given options but not too many options. Parties discussed the appropriate choice architecture which implied a distinction between good choice and bad choice, pointing out that customer choice is not always a positive. Parties did note the benefits of including and/or encouraging automation or auto demand response attributes to PEV rates.

Staff Observations

Staff suggests that rate design navigate the spectrum between simple shared-cost allocation and more complex cost assignment. Staff gleaned from party comments that longer-term, residential rate design principles should provide choice and simplicity while maintaining a net cost-based (e.g., costs net of benefits) price signal. In the short-term, however, parties cautioned against overburdening this Rulemaking with comprehensive electric rate reform.

Staff suggests the Phase 2 decision provide both short and long-term rate design guidance. For example, it is conceivable that existing rates, once PG&E modifies E-9, will be adequate until 2013. In 2013, parties should meet and confer as to whether AB1X subsidies are problematic and discuss the advantages and disadvantages of mandatory PEV rates. At that point, two years would remain before ARB's LCFS would necessitate a separate or submeter. By 2013, however, there may exist HAN-enabled technology that could be put to the same purpose, more clarity around the LCFS may be presented, and more PEV load profile data will be available from the CHARGEPOINT and EcoTality studies.

Findings

In the short-term, Staff recommends that a whole-house single meter opt-in non-tiered TOU rate is adequate, with the exception of PG&E's E-9 rate. In addition, staff recommends establishing a sub-metering alternative rate option. Staff would recommend development of a procedural timeline with respect to rate schedule adequacy.

In the long-term, perhaps as an aspect of comprehensive rate reform, Staff finds merit in exploring the benefits of including and/or encouraging automation or auto demand response attributes in PEV rates. Additionally, future PEV rates should entertain the possibility of a residential demand or facilities charge, as well as explore PV-PEV integration. Informed by a cost/benefit determination, residential rate design principles should provide choice and simplicity while maintaining a net cost-based (that is, costs net of benefits) price signal.

4. Non-Residential PEV Rates

Panelists:
Anne Bordetsky, BetterPlace
Barbara Barkovich, Principal, Barkovich & Yap, Inc.
Paul Heitmann, EcoTality
Ed Pike, ICCT
Russ Garwacki, SCE

This panel addressed questions related to grid stability, price signals for EVSP customers, considerations given to ESPs as well as which cost assignment or load shifting mechanism might be utilized in the non-residential context.

Party Positions

EVSPs argued that a level playing field should be maintained in consideration of rate schedules for non-residential PEV charging (this principle would equally apply to EVSPs that seek to offer charging services at residential customer sites). For example, during on-peak hours, IOU residential rates may be less than rate schedules for which EVSPs operating at residential sites would qualify. Alternatively, EVSPs may offer charging for free, undercutting the effectiveness of IOU residential or non-residential price signals. One party stated that if all rates are cost-based then the level playing field is not an issue, irrespective of customer classification and schedule assignment. This determination may be based on facility kW and utilize existing commercial TOU rates. But most parties agreed time-differentiated rates for EVSPs and all other customers are important to send an accurate price signal reflecting the higher cost of charging on-peak.

Panelists discussed two scenarios related to the relationship between the utility and non-utility EVSP. In one, the EVSP is an end-use customer of the IOU and therefore pays a bundled rate. In the other, the EVSP is also an ESP and therefore only pays for delivery and not generation of energy. Staff inquired as to the need for a time-differentiated delivery rate, volumetric or fixed demand charge, since without the generation component there exists no means by which to influence EVSPs to shift load. Parties stated that it would be difficult to isolate the distribution component for EVSPs as a time-differentiated distribution rate. This may necessitate a change in the bundled distribution rate for EVSPs. EVSPs stated that demand charges may have a chilling effect on a nascent industry. EVSPs also supported a price cap on PEV rates not exceed the gasoline price equivalent.

One party stated that EVSP TOU rates should reflect at least a 4:1 on-peak to super-off-peak rate differential in order to effectively shift load. Another party proposed that the Commission address the flat rates Detroit Edison recently instituted for the EVSP-equivalent. In response, another party asserted that flat rates are essentially on-peak rates that are subsidized by off-peak rates.

Generally parties seemed to be in agreement that cost assignment should follow load and therefore the Commission should look to assign costs on the basis of load characteristics of a class of customers. One party stated that rate design traditionally centers around aggregate costs rather than specific end-uses. Another party stated that non-residential rates do not have nearly the level of restrictions of residential rates.

EVSPs pointed out that, as PEV mobility service providers, they provide smart charging ancillary services which must be reflected in the costs borne by EVSPs. EVSPs, as demand response aggregators, provide grid stability mitigation benefits, the avoided costs from which need to be addressed in the design of EVSP rates. Another party pointed out that there are already demand response aggregators and a utility market for demand response services.

One party stated that ESPs that provide customers with direct access effectively provide fixed rates and allow direct customers to bypass dynamic rates.

Parties suggested the Phase 2 decision should address how to define an EVSP for purposes of rate schedule qualification. In the short-term, EVSPs may be assigned to certain non-residential rates.

Staff Observations

Staff agrees with parties that the Phase 2 decision should consider how to define an EVSP for purposes of rate schedule qualification.

Staff also believes that the case in which ESPs provide fixed rates that bypass dynamic rates is a concern that should be addressed through the distribution and demand charge rate structure, if it is determined that existing rates do not prove to be sufficient to recover additional infrastructure costs associated with this potential new type of distribution utility customer. Consequently, the proposed longer-term revaluation of the (bundled) PEV customer rate design, once the market is further developed and additional data have been collected, should include an evaluation of the distribution system impacts and associated cost recovery for EVSP/ESP customers, if any have emerged in the market..

Findings

In the short-term, Staff recommends adopting a definition of an EVSP for purposes of rate schedule qualification. This definition may include: PEV mobility service providers or DR aggregators or ESPs, all, both, some other entity altogether.

In the long-term, Staff recommends addressing 'level playing field' concerns raised by assigning costs (and benefits) on the basis of load characteristics of a class of customer. This will likely require quantifying the EVSP grid stability mitigation benefits. Also, non-residential rates should explore time-differentiated distribution rates and/or demand charges.

5. Education and Outreach

Panelists:
Dan Bowermaster, PG&E
Greg Haddow, SDG&E
Joel Pointon, SDG&E
Kevin Nesbitt, U.C. Davis

This panel addressed questions related to lessons learned from past studies, pilots and programs, including the characteristics of customer engagement, which behaviors to encourage/discourage and whether or not PEV rates need to be more consistent across IOUs.

Party Positions

Parties stated that education and outreach should not be limited to ratepayers but rather should extend to communities at large. Parties stated that local jurisdictions lack the funding but must be included for purposes of streamlining EVSE installation.

Parties stated that customers desire metrics with regard to energy efficiency (e.g., kWh/mi versus mi/gallon conversions) and emissions reductions (e.g., CO2, % renewable). Metrics provide assistance to PEV owners in reconciling the increase in electricity costs with the decrease in gasoline costs. Parties referenced online rate calculators as a particularly useful tool for enabling the customer.

Staff Observations

The Phase 2 decision should address how best to ensure utility notification. The Phase 2 decision should also address whether IOUs are the appropriate point of contact and whether ratepayer funding should be appropriated for PEV owner education and outreach.

Findings

In the short-term, staff recommends that a data repository be established as information sharing is essential in order to mitigate duplication of efforts. Staff also recommends that there be a determination as to whether or not the IOUs are the appropriate point of contact and whether ratepayer funding should be appropriated for PEV owner education and outreach. Online rate calculators appear to be a particularly useful tool for enabling the customer. If IOUs are determined to be the appropriate contact, utility notification via opt-in PEV purchase agreements appears crucial.

(END OF REVENUE ALLOCATION AND RATE DESIGN WORKSHOPS – SEPTEMBER 29 and 30, 2010)