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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.

[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/

Senate Bill 626

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?

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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

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:

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?

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

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 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

[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.

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.

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.

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[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.

1.3 REVENUE ALLOCATION AND RATE DESIGN

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

[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.

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]

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.

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

[15] Ibid

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

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

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 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

[18] Voltage Alternating Current

[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

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 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

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

[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?

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 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)

[26] Ibid

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 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.

[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?

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.'**

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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.

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 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

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

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 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

[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.

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 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.

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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

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 secondary system upgrade is less than or equal to the allowance, the 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].

[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.

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 (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.

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

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

[44] Ibid

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.

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

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

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

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.

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

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[47] PU Code 739(d)1

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.

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.

[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.

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

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

[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

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 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

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

[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

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 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

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[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?

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] 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).

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

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.

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.

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[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

[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

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 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.

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[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?

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 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.

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

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

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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.

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 (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

[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

6) Education and outreach[68]

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.**

[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?

[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 ATTACHMENT)