Table 11. Factors for Monetizing Societal Benefits

Societal Benefit	Unit	2013	2020	2030
Displaced Petroleum[1],[2]	$/GGE	$0.44	$0.43	$0.42
NOx[5],[6]	$/ton	$4,675	$5,082	$6,098
PM [41,42]	$/ton	$1,450,038	$1,650,681	$1,977,357
VOC[41,42]	$/ton	$1,118	$1,20	$1,423

Table 12. GHG Values

GHG Cost	Unit	2013	2020	2030
Phase 1 Report [3],[4]	$/Metric Ton	$11	$12	$16
CPUC Avoided Costs	$/Metric Ton	$17	$37	$73
Societal Value	$/Metric Ton	$49	$56	$70

[1] Leiby, P. Estimating the Energy Security Benefits of Reduced U.S. Oil Imports, ORNL/TM-2007/028, March 2008
[2] EPA RFS Annual Rulemaking, Updated Energy Security Benefits, 2012. EPA-HQ-OAR-2010-0133-0252, Available online at: http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0133-0252
[5]Diesel Emissions Quantifier Health Benefits Methodology, EPA, EPA-420-B-10-034, August 2010. Available online: http://www.epa.gov/cleandiesel/documents/420b10034.pdf
[6] EPA/HNTSA, Draft Joint Technical Support Document: Proposed Rulemaking for 2017-2025 Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards, EPA-420-D-11-901, November 2011.
[3] Interagency Working Group on Social Cost of Carbon. 2010. Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866. February. United States Government. http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf
[4] Interagency Working Group on Social Cost of Carbon. Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, United States Government, May 2013.

Table 13: Detailed Cost Test Components for PEV Charging Load Increase

Component	PCT	RIM	TRC	SCT (740.8)
PEV Customer costs and benefits				
Incremental Vehicle Costs	-		-	-
Gasoline Savings	+		+	+
Utility Bills	-	+		
Federal Tax Credits	+		+	+
State Tax credits	+			
PEV Charger Cost				
Utility Asset		-	-	-
Customer Assets	-		-	-
Admin Costs				
Utility Program Administration		-	-	-
Electricity Supply Costs				
Energy Costs		-	-	-
Losses Cost		-	-	-
A/S Cost		-	-	-
Capacity Cost		-	-	-
T&D Cost		-	-	-
RPS Cost		-	-	-
Utility GHG Allowance Costs		-	-	-
Societal Benefits				
Transportation GHG Allowance Costs			+	+
"Societal" value for CO2				+
Health benefits				+
Decreased Petroleum Use				+

6. Cost-Effectiveness Results

We present the cost-effectiveness results using two metrics. The first is the present value of costs and benefits through 2030, provided in 2014 dollars. The second is the present value costs and benefits per PEV, also in 2014 dollars. Unless otherwise specified, the results presented are for the ZEV Most Likely adoption and TOU rate scenarios.

6.1. PEVs Provide Regional Economic Benefits

Detailed TRC results are shown in Figure 16 for the ZEV Most Likely – TOU Rate and Load Shape Scenario. The levelized benefits – the federal tax credit, gasoline savings and reduced GHG emissions – total about $20,000 per vehicle.[47] The costs include incremental costs of the vehicle, charging infrastructure costs, distribution system upgrades, and the CPUC DER costs for delivered energy.

[47] Per the Standard Practice Manual, the TRC for California includes federal, but not state, tax credits and rebates as a benefit.

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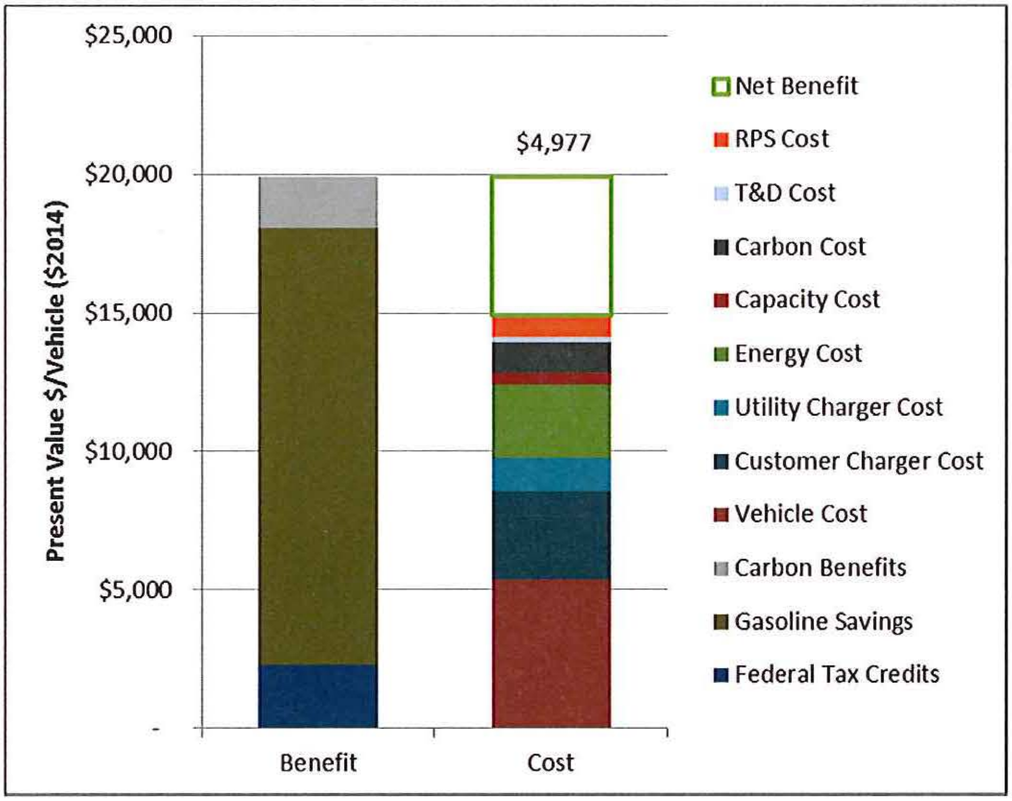

Figure 16. Per Vehicle TRC Costs and Benefits TOU Rate Scenario

The TRC costs for the four rate and load shape scenarios are shown in Figure 17 and Figure 18. The costs of providing energy are the same for the Tiered and Flat rate scenario, which provide no incentives to shift charging to off-peak hours. Under these two scenarios, the TRC net benefit is $3.14 billion or $3,597 per vehicle. With more charging shifted away from peak hours, the TRC net benefits are higher under the Mixed and TOU rate/load-shape scenarios. The net benefits under the TOU scenario are $4.34 billion, equivalent to the $4,977 per vehicle shown above.

The $5,000 net TRC benefits under the TOU rate/load shape scenario are $1,400 per vehicle (28%) higher than the $3,600 per vehicle for the tiered and flat rate scenarios. Charging off-peak reduces the cost of generation, including carbon allowances, by $740 per vehicle. It also defers or avoids investment in and generating, transmission and distribution capacity for a combined benefit of $640 per vehicle. Under the ZEV Most Likely Adoption Scenario the present value benefit of TOU as compared to flat rate charging is $1.2 billion.

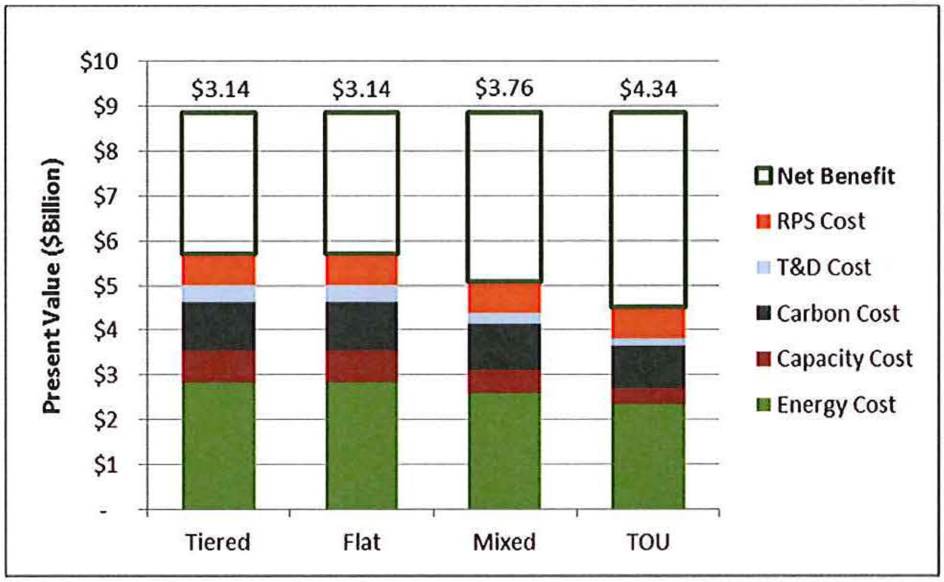

Figure 17. Present Value TRC Electricity Costs and Net Benefits by Rate Scenario

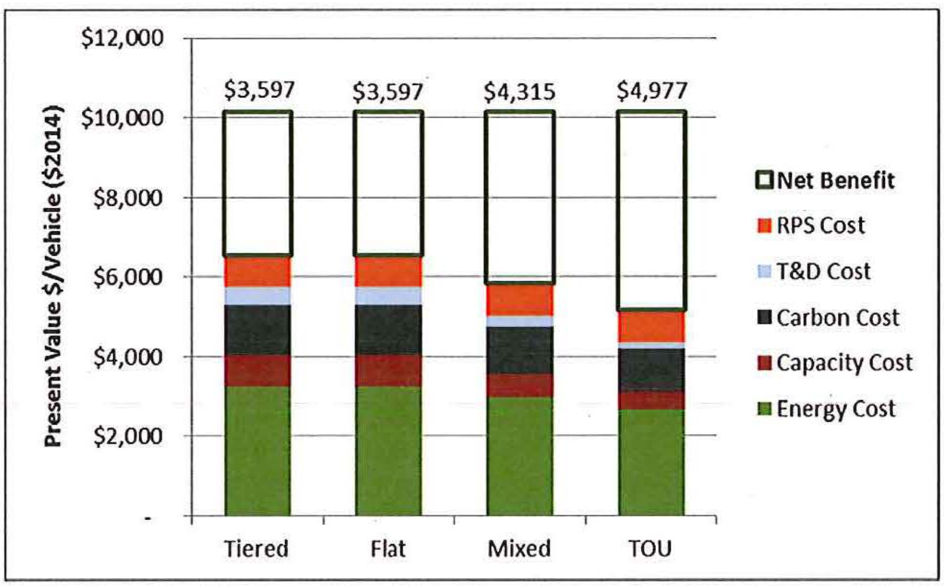

Figure 18. Per Vehicle TRC Electricity Costs and Net Benefits by Rate Scenario

Schedule DRI-3

6.1.1. VEHICLE COST ASSUMPTIONS

The incremental vehicle costs of PEVs relative to comparable ICE vehicles are expected to decline over time (Table 14). Vehicle cost reductions that come with technological learning and increasing economies of scale depend on growing adoption of PEVs. It is often the case for new technologies with promising potential to transform markets, programs to encourage adoption with education and incentives are required. Here we see the importance of the federal tax credit (Table 15) for PEVs in the TRC.

Table 14: Incremental Vehicle Costs[48]

	2014	2020	2030
PHEV10	5,121	2,524	399
PHEV20	10,241	5,047	798
PHEV40	13,535	6,448	1,597
BEV	14,205	5,151	197

Table 15: Federal Tax Incentive[49]

Vehicle	Incentive
PHEV10	$2,500
PHEV20	$4,000
PHEV40	$7,500
BEV	$7,500

The TRC costs and benefits are shown over time in Figure 19 (in present value nominal dollars for each respective year of adoption). In 2015, net economic benefits for California of roughly $3,500 per vehicle are achieved only with the inclusion of the federal tax credit. By 2023, caps for the federal tax credit have been reached, but vehicle costs have declined and gasoline prices increased such that there are net benefits of about $2,500 (in $2023) per vehicle even without the federal tax credit. By 2030 PEVs are nearing parity with comparable ICE vehicles in

[48] TEA Phase 1 Report, Table 53, p. 85
[49] TEA Phase 1 Report, Table 53, p. 85

terms of cost and the net benefits have risen to around $5,200 per vehicle (in $2030)

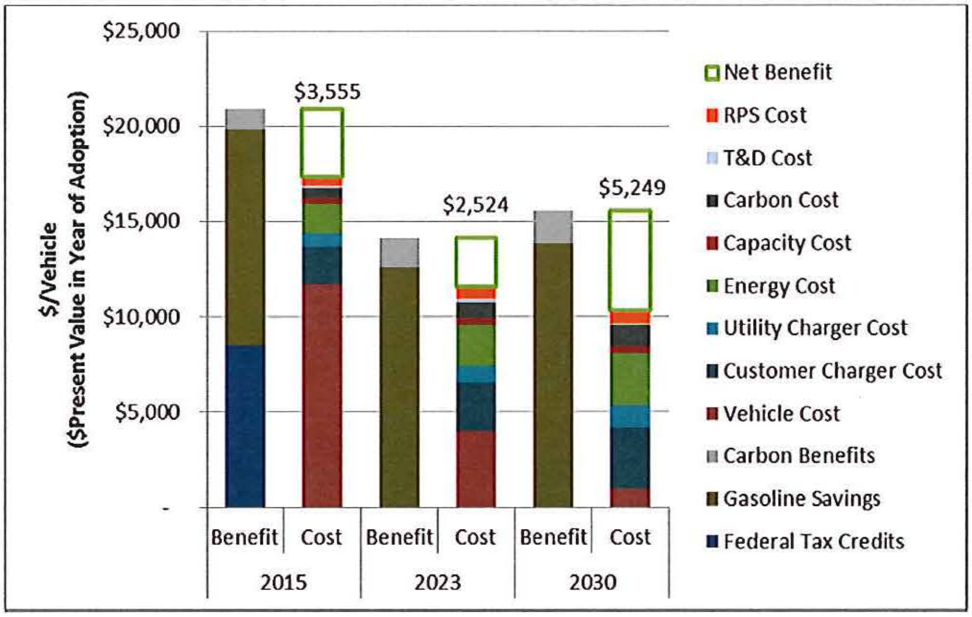

Figure 19. Per Vehicle TRC Electricity Costs and Net Benefits by Rate Scenario

6.2. PEVs Provide Societal Benefits

With the addition of the environmental and health benefits described in Public Utility Code 740.3 and 740.8, the net benefit calculated with our "740.8" SCT is nearly $1 billion than the TRC. The net benefit per vehicle is $6,200, 24% higher than for the TRC.

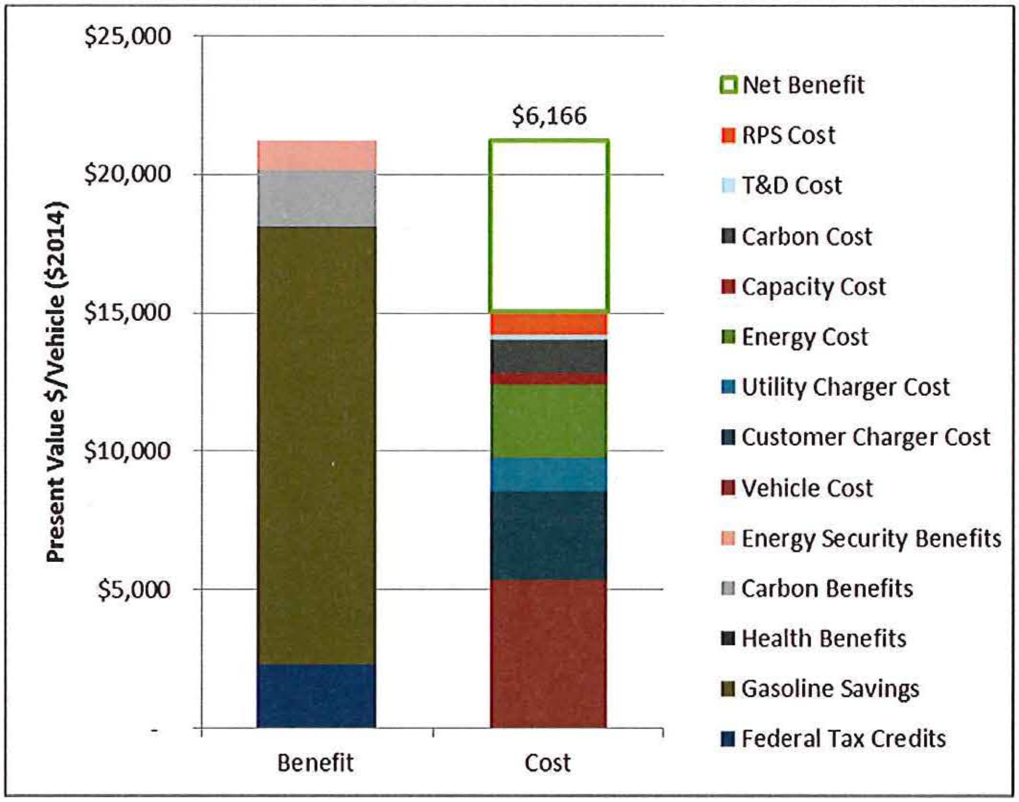

Figure 20. Per Vehicle SCT Costs and Benefits

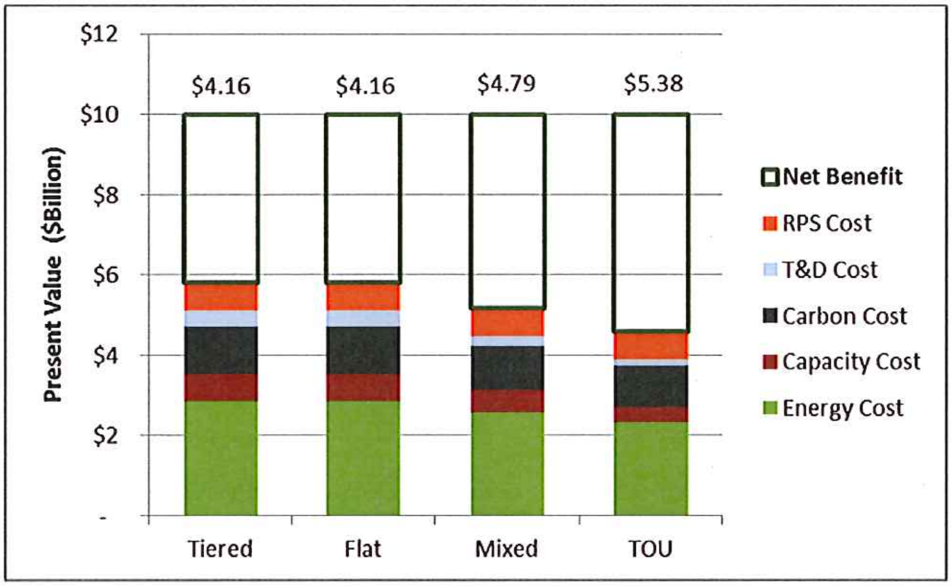

Figure 21. Present Value SCT Electricity Costs and Benefits by Rate Scenario

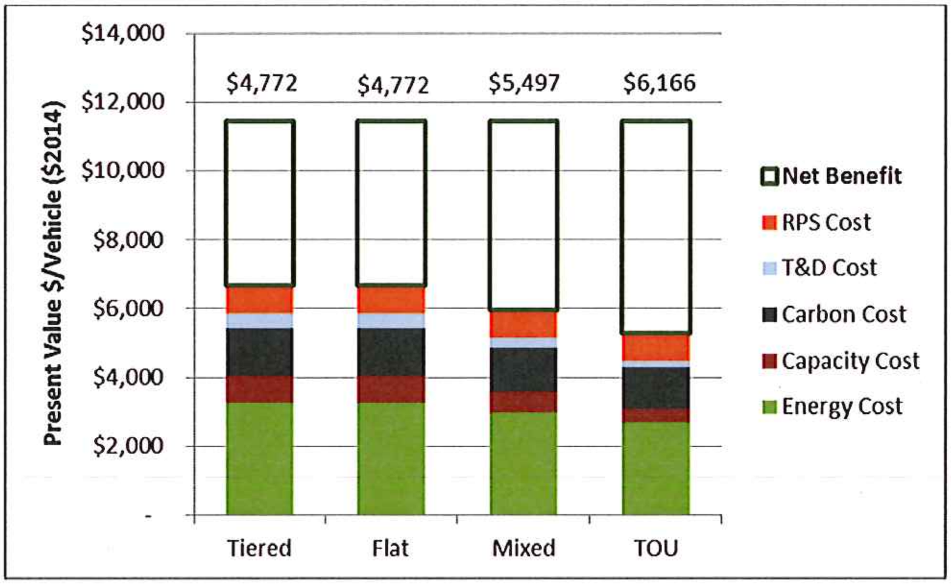

Figure 22. Levelized per Vehicle SCT Electricity Costs by Rate Scenario

6.3. PEV Charging Reduces Rates for All Ratepayers

The present value of utility customer benefits through 2030, calculated using the RIM test, is shown for the ZEV Most Likely adoption scenario with the utility obligation to serve division of infrastructure cost (Figure 23). The Tiered and Flat Rate Scenarios have the highest costs of the rate scenarios, but they also have the highest revenues. The high revenues outweigh the high costs, resulting in the highest net benefits, respectively $8.11 and $3.90 billion. The revenues and costs of delivered energy are lower under the Mixed and TOU rate and load shape scenarios, but the net benefits are still positive by $3.12 and $2.26 billion. With the rates used in our analysis, the RIM test is positive under all scenarios and sensitivities studies. The TOU rate scenario yields lower net revenues for the utility and its ratepayers, but also provides lower costs for delivered energy (next section) and higher net benefits for PEV owners, which encourages adoption.

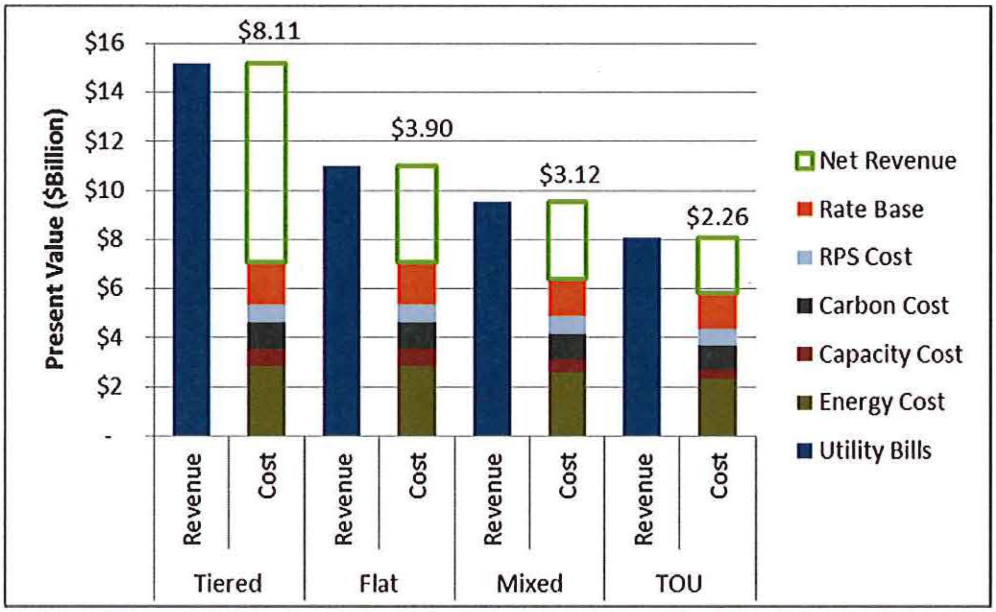

Figure 23. Present Value RIM Revenues and Costs by Rate Scenario

The same results presented in present value dollars per vehicle are shown in Figure 24. The levelized ratepayer benefits range from roughly $9,300 to $2,600 per vehicle.

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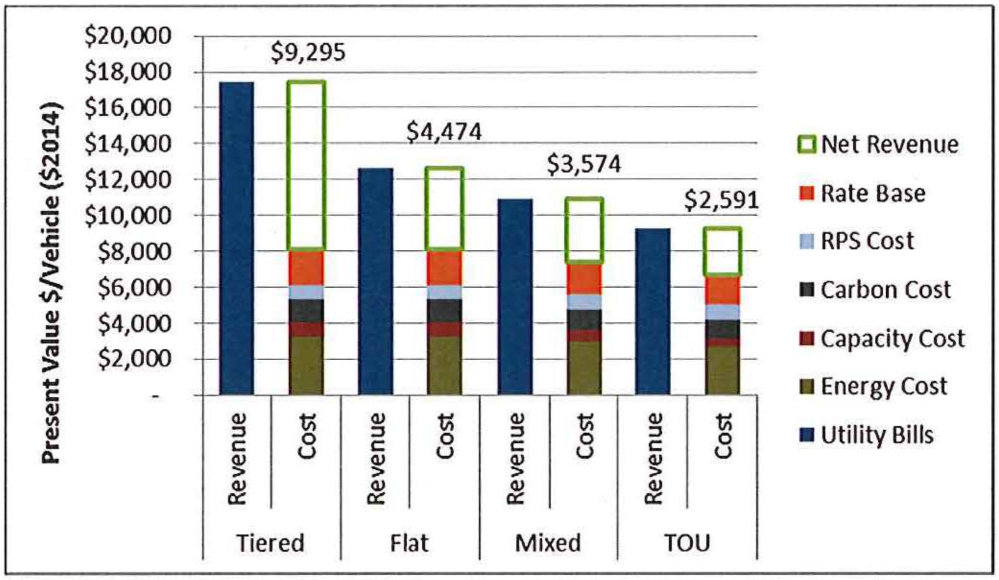

Figure 24. Present Value per Vehicle Ratepayer Costs and Benefits by Rate Scenario (ZEV Most Likely Vehicle Adoption)

6.3.1. RATE ASSUMPTIONS

Proposals for alternative rate designs are under active consideration at the CPUC. For this analysis, we do not attempt to predict the outcome of those proceedings, but instead model a range of alternative rate designs, including tiered, flat, and TOU rates. Rates assumptions are developed from existing tariffs and utility input and are not intended to be precise forecasts (Table 16). Tiered rates (Table 17) are taken from Decision 14-06-029 in the Rate Structure Proceeding (R. 12-06-013).[50]

[50] See CPUC Decision 14-06-029 , Attachment E, "Comparison of Non-CARE Rates".

Table 16: Average Charging Rates in 2014

Cents/kWh	PG&E	SCE	SDG&E	SMUD
Residential				
Tiered Rate	27.4	26.1	32.3	17.6
Flat Rate	18.0	18.0	18.0	17.8
Mixed Rate	15.7	13.5	18.5	13.5
TOU Rate	11.2	10.5	17.2	9.2
Commercial				
Commercial	20.7	10.4	13.9	11.4

Table 17: Tiered Rate Charging Assumptions

Cents/kWh	PG&E	SCE	SDG&E	% PEV Charging	SMUD	% PEV Charging
Tier 1	14.7	14.9	17.3		9.5	1%
Tier 2	17.6	19.3	20.4	33%	17.8	99%
Tier 3	29.6	27.9	37.7	33%		
Tier 4	35.7	31.9	39.7	33%		

7. Dynamic Vehicle Grid Integration

Supporting higher penetrations of renewable generation on the electric grid is an additional benefit that can be provided by PEVs. This benefit is not included in the cost-test results presented above, but is illustrated here as a potential benefit that merits further investigation and analysis.

We illustrate the potential benefits using the dynamic VGI charging model developed by E3 to support SDG&E's application that is currently before the CPUC (A. 14-04-014). The model minimizes the cost of charging to PEV customers based on assumed driving patterns and price signals provided in the form of retail electric rates. This model uses a high RPS avoided cost scenario described below to quantify the costs of PEV charging under a 40% RPS scenario.

The model developed for the SDG&E application models dynamic VGI benefits using an hourly VGI rate that is determined in the day-ahead and sent as a price signal via a retail rate for PEV charging. The benefits illustrated here are not specific to the approach proposed by SDG&E. Rather, they are generalizable to any proposed approach or program that directly controls or incentivizes PEV charging specifically to manage flexibility challenges that are anticipated under higher renewable penetration levels.

7.1. Flexibility Challenges

Using E3's stochastic production simulation model REFLEX, E3 quantified the flexibility needs of the California grid under 40 and 50% RPS scenarios.[51] REFLEX is specifically designed to investigate flexible capacity needs and value with variable renewable resources (VER). REFLEX performs random draws of weather-correlated load, wind, solar, and hydro conditions taken from a very large sample of historical and simulated data. It characterizes the need for system ramping capability through stochastic treatment of load, wind and solar generation, hydropower conditions, dispatchable generator outages and other random variables on multiple time scales: annual, monthly, diurnal, hourly and sub-hourly. The model uses

[51] See https://ethree.com/public_projects/reflex.php

optimal unit commitment and economic dispatch to model the ability of the system's dispatchable resources to respond to a full range of conditions. Flexibility violations such as shortages in upward or downward ramping capability are characterized according to their likelihood, duration and depth, using metrics that are analogous to conventional reliability metrics such as LOLP, Loss of Load Probability Expectation (LOLE), and Expected Unserved Energy (EUE).

There are five distinct types of flexibility challenges that the system will face under high renewable penetration:

1. **Downward ramp**: as solar generation increases in the morning, flexible resources will be needed to ramp generation down (or ramp load up).
2. **Minimum generation**: to accommodate solar generation during the day, fossil generation will need to turn off, or operate at minimum levels, but still be ready to increase generation in the late afternoon and early evening.
3. **Upward Ramp**: in the evening, as solar generation declines, other generating resources will need to ramp up (or load ramp down).
4. **Peaking Capacity**: sufficient resources will be needed to meet peak loads with sufficient reserve margins.
5. **Sub-hourly Flexibility (not shown)**: flexible resources will be required to provide both existing and new types of ancillary services, including frequency regulation, flexi-ramp and load following.

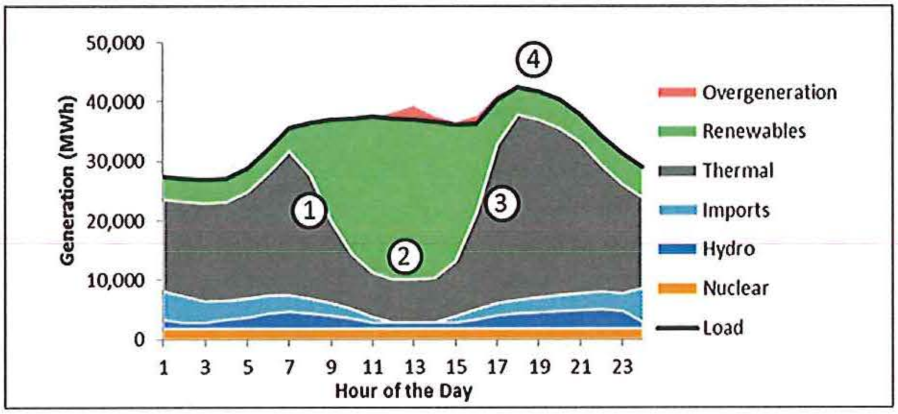

Figure 25: Renewable Integration Challenges

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The Utility High RPS Study models flexibility needs in high RPS scenarios in 2022 and finds that the largest renewable integration challenge is "overgeneration". [52] Overgeneration occurs when "must-run" generation—non-dispatchable renewables, combined-heat-and-power (CHP), nuclear generation, run-of-river hydro and thermal generation that is needed for grid stability—is greater than loads plus exports. Overgeneration can occur even in a highly flexible power system if there is simply not enough load to absorb the available quantity of renewable energy during a given hour. However, additional overgeneration or curtailment of renewable output may occur due to lack of power system flexibility as well.

7.2. High RPS Energy Values

Hourly incremental energy value estimates are developed using the E3 Renewable Energy Flexibility (REFLEX) model and the E3 Renewables Portfolio Standard (RPS) model.[53] Using these models, E3 developed a California statewide dispatchable resource supply stack which ranks generators by variable energy cost, including the cost of carbon dioxide (CO_2) emissions. The resource stack is used to correlate statewide net load and marginal energy value. E3 uses a gross load forecast with two renewable penetration levels: 33% and 40%.[54] The 33% renewable penetration level represents the 33% RPS goal for the California utilities and the 40% level represents the 33% RPS plus future renewable and distributed photovoltaic installations.[55]

Statewide hourly net load data (statewide gross load forecast[56] minus renewable generation) are created for eight representative day types described below. The end results are marginal hourly energy prices in dollars per kWh for each hour for each of the eight day types. The eight day types are weighted to represent a 365-day year. Table 6-8 describes the eight day types selected to reflect combinations

52 E3. "Investigating a Higher Renewables Portfolio Standard in California." (2014)

53 See E3's 33% RPS Calculator with Output Module: https://www.ethree.com/documents/LTPP/Model%20w%20OutputModule%20-%202007.zip.

54 *See* E3's "Renewable Energy Flexibility (REFLEX) Results California ISO Webinar" (December 9, 2013), http://www.caiso.com/Documents/RenewableEnergyFlexibilityResults-Final_2013.pdf

55 See SDG&E's current Net Energy Metering enrollments and enrollment MW cap: http://www.sdge.com/clean-energy/net-energy-metering/overview-nem-cap.

56 See "California Energy Demand 2014 - 2024 Final Forecast, Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency" - Final Staff Report. CEC-200-2013-004-SF-V1 (December 2013), http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-SF-V1.pdf.

of gross load conditions (high or low) and renewable generation conditions (high or low). Each day type was assigned a weight, such that the eight day types can be combined to represent a full year. This energy price component replaces the DER model's energy price.

Table 18: 40% RPS Representative Day Types

Day #	Month	Day Type	Load Level	Renewable Level	Day Weight (%)
1	March	Weekday	Low	High	10.1%
2	March	Weekend	Low	High	8.2%
3	July	Weekday	High	High	7.1%
4	September	Weekday	High	Low	6.6%
5	September	Weekend	High	Low	0.3%
6	August	Weekday	High	High	15.6%
7	November	Weekend	Low	Low	20.0%
8	December	Weekday	Low	Low	32.1%

We recalculate the CPUC "standard" avoided costs using the generation portfolio and net load shape for the 40% RPS scenario. This provides a new set of 8,760 hourly avoided costs. The energy prices are taken from the REFLEX model and system and T&D capacity value allocated to the highest net load hours in our future RPS scenario.

We use the 40% RPS avoided costs to illustrate the benefit of using PEV loads as a flexible resource. During a March weekend with low loads and high renewables, avoided costs are negative during the day, indicating that there is a value to adding load to absorb overgeneration and reduce the morning and evening MW ramp requirements. In a September weekday high load low renewables day, avoided cost values are negative in the early afternoon, but extremely high later in the day due to the allocation of system and T&D capacity values to those hours.

7.3. Benefits of Dynamic Charging for Renewable Integration

To demonstrate the benefits of dynamic VGI charging, we compare the cost of delivering electricity for PEV charging under a TOU rate and dynamic hourly VGI rate scenario. We assume that vehicle adoption, eVMT, and charging infrastructure costs remain the same between the TOU and VGI scenario. The hourly avoided costs of delivered energy for PEV charging also remain the same. The only difference between the scenarios is the retail PEV charging rate and the timing of when the charging occurs.

We recalculate the CPUC "standard" avoided costs using the generation portfolio and net load shape for the 40% RPS scenario. This provides a new set of 8,760 hourly avoided costs. The energy prices are taken from the REFLEX model and system and T&D capacity value allocated to the highest net load hours in our future RPS scenario.

We use the 40% RPS avoided costs to illustrate the benefit of using PEV loads as a flexible resource. During periods with low loads and high renewables, avoided costs are negative during the day, indicating that there is a value to adding load to absorb overgeneration and reduce the morning and evening MW ramp requirements. Avoided costs are high later in the day driven both by the evening ramp requirements and the allocation of system and T&D capacity values to peak load hours.

With the TOU rate scenario, residential charging occurs on SDG&E's EV-TOU rate and commercial charging under AL-TOU. These rates provide consistent TOU rates for the summer and winter months respectively. The VGI scenario uses a dynamic hourly rate based on the avoided costs developed for the 40% RPS scenario shown above.

The impact of a dynamic VGI rate on PEV charging behavior is illustrated in Figure 26 and Figure 27. With the TOU rate, most charging occurs at night at home when the TOU rate is the lowest. Some charging occurs at work in the late morning as vehicles arrive at work and before the on-peak TOU period. The TOU rate does successfully discourage charging during the evening ramp and peak net load period, but does not actively encourage charging to absorb overgeneration. Note also that nighttime charging spikes at midnight as all PEVs start charging immediately at the start of the super off-peak TOU period.

The dynamic VGI rate is designed to mirror hourly avoided costs (Figure 27). This has two positive impacts. The nighttime charging is shifted to the early morning and the peak charging level is reduced. This reduces the early morning ramp rate as load increases before solar generation begins. In addition, a significant portion of the charging is shifted to the late morning/early afternoon during peak solar generation and minimum net loads. The avoided-cost value is negative during the day and high during the peak net load hour of hour ending (HE) 19. This indicates that increasing load during the afternoon has a positive value, absorbing overgeneration and reducing the net load ramp in the late afternoon/early evening.

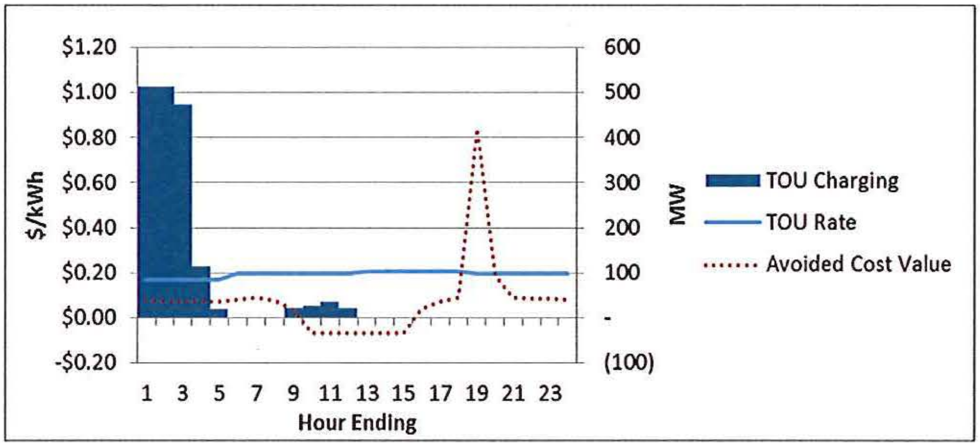


Figure 26. TOU PEV Charging, Retail Rate and Avoided Cost Value – March Weekday: Low Load/High Renewables

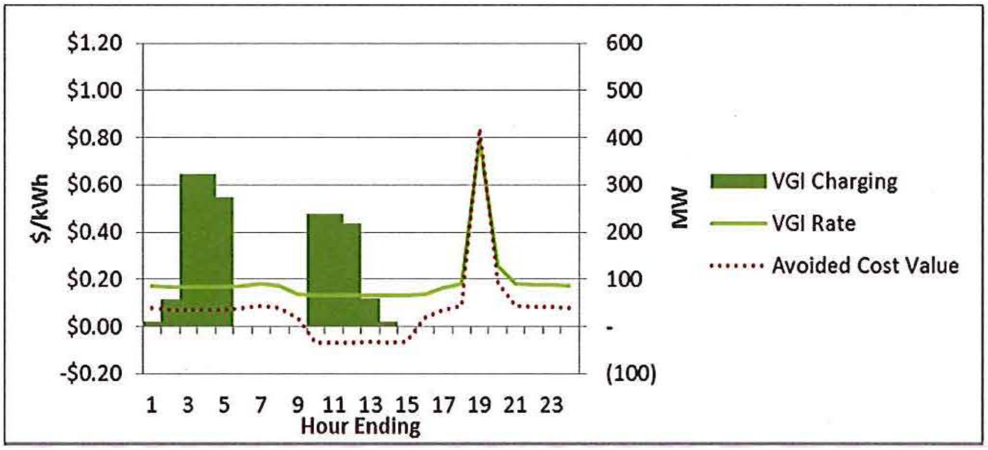


Figure 27. VGI PEV Charging, Retail Rate and Avoided Cost Value – March Weekday: Low Load/High Renewables

Both the TOU and VGI rate successfully discourage charging during peak loads. However, the TOU rate is constant across the summer and winter seasons and does not follow changes in renewable generation and net loads that will change dramatically in the spring and the fall under a 40% RPS scenario. The VGI rate, on the other hand, can encourage afternoon charging in the spring and fall when overgeneration is high, but discourage charging during the same period in the summer when afternoon loads exceed renewable and must take generation.

For this illustrative example, The VGI scenario reduces the present value of charging costs per vehicle form around $1,400 to under $600 - a net benefit of $850 per PEV (Figure 28). This represents a cost reduction from the RIM, TRC and SCT perspective. Due to different assumptions and time periods, these results are not directly comparable to the cost-benefit results presented above.

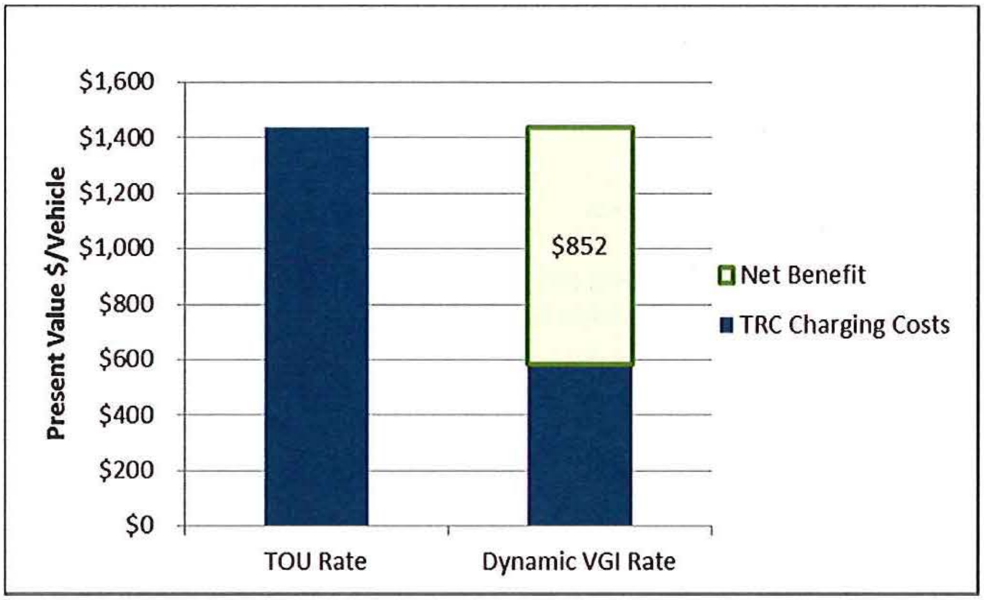


Figure 28. Present Value TRC Charging Costs per Vehicle

These illustrative benefits of dynamically managing charging with an hourly VGI rate must be presented with two caveats. First, we are comparing a seasonally adjusted TOU rate from today's tariffs with a future 40% RPS scenario. A TOU rate in a 40% RPS world might look different than today, adjusting monthly rather than seasonally for example. This would shrink, but not eliminate the relative benefits of VGI charging. Second, increasing daytime charging may impose additional costs on the distribution grid, even if charging during peak load hours can be avoided. These results assume that no additional distribution upgrades are required.

8. Evaluating PEVs as a GHG Reduction Strategy

We show that PEVs can pass current cost-effectiveness evaluation methods that were developed to evaluate supply and demand side resources on a comparable basis in utility resource planning. In the existing framework, demand side resources that reduce or shift load are valued for reducing the costs and emissions required to meet forecasted demand for energy. These values are based largely on the costs of today's conventional resources supply side resources that are avoided with distributed resources.

Meeting GHG goals and air quality requirements will require transformative acceleration of PEV adoption and unprecedented levels of coordination and cooperation between the utility and transportation sections. New cost-effectiveness metrics are needed to support the infrastructure development to accomplish these goals.

8.1. New Metrics for Evaluating Cost-Effectiveness are Needed

The cost tests presented above were developed to evaluate supply and demand side resources on a comparable basis in utility resource planning. Demand side resources that reduce or shift load reduce are valued for reducing the costs and emissions required to meet forecasted demand for energy. The costs of supply side resources avoided with distributed resources are based largely on today's conventional resources.

PEVs are fundamentally different from other distributed energy resources in two key respects. First, PEV's provide net benefits and emissions reductions to California, but the generation needed to serve PEV load will result in emissions increases in the power sector. Second, whereas the primary purpose of promoting DER has been to reduce the costs and emissions required to <u>meet forecasted load</u>, California seeks to accelerate PEV adoption to <u>meet GHG reduction and air quality targets</u>. Furthermore, achieving these goals will require fundamental market transformation in both the utility and transportation sectors with new and unconventional technologies that are not widely used today.

Although we show that PEV's can be cost-effectiveness using existing CPUC and CARB methodologies, these tests were not developed to address these statewide challenges. We propose that new tests are needed to evaluate initiatives designed to meet long-term GHG reduction targets. Even with the addition of health and environmental benefits, early investments intended to encourage market transformation often do not pass cost-effectiveness evaluation initially, but only after technological development and wide-spread adoption drive costs down.[57] Furthermore, current tests do not explicitly address how environmental and GHG benefits in the transportation sector can or should be considered against increased emissions in the utility sector. New approaches will need to be developed to compare the relative costs of achieving GHG reductions across utility, transportation and other sectors of California's economy.

[57] Emerging technology programs in energy efficiency are a prime example - the purchase price and cost of ownership for LED bulbs, compact florescent bulbs (CFLs) and front-loading clothes washers have fallen even as performance has increased.

9. Conclusions

In this TEA Phase 2 Report, we quantify the costs and benefits of plug-in electric vehicles (PEVs) for utilities, their customers and the state of California. We use cost-effectiveness methods from the California Air Resources Board (CARB) and the California Public Utilities Commission (CPUC) to show that PEVs reduce rates for utility customers and provide net economic and societal benefits for California as a whole. A detailed analysis of PEV clustering finds only modest cost impacts for the distribution system, but more accelerated deployment of multi-family, public and workplace chargers may pose higher infrastructure costs. Even with modest distribution system impacts, there is a significant benefit for managed charging in reduced generation, carbon and infrastructure cost. Even though we find PEVs are cost-effective using existing cost tests, new tests are needed to properly evaluate PEVs a GHG reduction strategy that requires rapid transformation in both the utility and transportation sectors.

Our conclusions from the analysis performed for this study are:

+ PEV charging increases the utilization of the existing distribution system and requires only modest feeder and substation upgrade costs, even under the most aggressive adoption scenario.
+ Managed charging, either through utility dispatch or pricing incentives (and without vehicle-to-grid capability), lowers the cost of PEV charging and the infrastructure required to support it. Net total resource cost-test benefits increase by 28% relative to the non-TOU rate scenarios.
+ "Make ready" costs for multi-family, public and workplace charging are larger than distribution upgrade costs and may pose a more significant barrier to PEV adoption.
+ Over the long-term, PEV rates can be designed to provide sufficient net revenues to more than cover short-term and long-term marginal costs, lowering average rates for non-PEV owners in the rate class.

- Over time, with reduced incremental vehicle costs and increasing gasoline prices, PEVs provide net total resource cost-test benefits for California even without the federal tax credit.
- In the near-term, accelerated investment in enabling technology and infrastructure is needed to support PEV adoption and market transformation. Such investment may not pass current cost-effectiveness tests, but still provide net utility customer and societal benefits in the long-term.
- Current CARB and CPUC cost-effectiveness tests evaluate resource measures largely against "traditional" investments based on current technology. More comprehensive methods are need to evaluate alternative strategies towards meeting GHG and ambient air quality targets, which will require significant investment in new technologies and infrastructure.
- Dynamic charging can provide significant additional benefit under high RPS scenarios by absorbing overgeneration and reducing morning and evening ramps. In our illustrative example the benefits from an hourly dynamic charging rate were about $850 per vehicle relative to a time-of-use rate.
- The increased benefits provided by time-of-use rates and dynamic charging show the quantifiable benefits of actively engaging both customers and utilities in managed PEV charging. Utility or government programs funding PEV charging infrastructure should also include strong incentives for PEV owners, site hosts and third party charging station operators to engage in managed charging that is responsive to grid needs.

The societal cost-test as presented here produces net benefits that are 22% higher than the total resource cost-test test using health and reduced reliance on imported petroleum benefits from the TEA Phase 1 Report. Alternative sources for benefit values could provide net benefits that are substantially higher.

Appendix A: 740.3 & 740.8 Text

§ 740.3: (a) The commission, in cooperation with the State Energy Conservation and Development Commission, the State Air Resources Board, air quality management districts and air pollution control districts, regulated electrical and gas corporations, and the motor vehicle industry, shall 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. Policies to be considered shall include both of the following:

(1) The sale-for-resale and the rate-basing of low-emission vehicles and supporting equipment such as batteries for electric vehicles and compressor stations for natural gas fueled vehicles.

(2) The development of statewide standards for electric vehicle charger connections and compressed natural gas vehicle fueling connections, including installation procedures and technical assistance to installers.

(b) The commission shall hold public hearings as part of its effort to evaluate and implement the new policies considered in subdivision (a), and shall provide a progress report to the Legislature by January 30, 1993, and every two years thereafter, concerning policies on rates, equipment, and infrastructure implemented by the commission and other state agencies, federal and local governmental agencies, and private industry to facilitate the use of electric power and natural gas to fuel low-emission vehicles.

(c) The commission's policies authorizing utilities to develop equipment or infrastructure needed for electric-powered and natural gas-fueled low-emission vehicles shall ensure that the costs and expenses of those programs are not passed through to electric or gas ratepayers unless the commission finds and determines that those programs are in the ratepayers' interest. The commission's policies shall also ensure that utilities do not unfairly compete with nonutility enterprises.

§ 740.8: As used in Section 740.3, "interests" of ratepayers, short- or long-term, mean direct benefits that are specific to ratepayers in the form of safer, more reliable, or less costly gas or electrical service, consistent with Section 451, and activities that benefit ratepayers and that promote energy efficiency, reduction of health and environmental impacts from air pollution, and greenhouse gas emissions related to electricity and natural gas production and use, and increased use of alternative fuels.

Appendix B: PEV Rate Impacts

9.1. PEVs Reduce Average Rates for All Customers

To illustrate the rate impacts of incremental load in general, consider the case of a customer adding a large HVAC unit to provide air conditioning. The customer will pay a retail rate for electricity to operate the HVAC unit. The $/kWh retail rate will usually include both an allocation of embedded fixed costs and the forecasted variable marginal costs of delivered energy to provide service to the customer. As a result, during most or perhaps even all hours of the year, the retail rate will exceed the utilities actual short-run marginal cost of delivered energy. The retail rate will therefore provide net revenues to the utility – revenues that will recover fixed costs incurred by the utility to serve load. If the net revenues are high enough, they may also fully recover the long-run marginal cost of delivered energy – including fixed costs for new generation and T&D capacity. Alternatively, the customer may sign up for a demand response or critical-peak pricing program such that the HVAC load can be served with minimal investment in new capacity. In either case, net revenue more than recovers long-term marginal costs to serve the customer's rate class. In such a case, the new HVAC load would reduce the allocation of fixed costs that must be recovered from all other customers, and, all else being equal, would reduce average rates for the customer class in the next rate case.

If, on the other hand, expensive new investments in generation or T&D capacity are required to serve the new HVAC load (that is coincident with utility peak loads), the retail rate may provide net revenues over and above short-term, but not long-term marginal costs. In this case, the new load will, all else being equal, increase average rates in the next rate case.

Turning specifically to the case of PEVs, we first consider a "default" case (Figure 1) where the customer charges their car with a relatively high domestic rate – either in a higher tier or during higher priced on-peak TOU periods. As in the HVAC case described above, the retail rate will provide net revenue above short-term variable costs and contribute to the recovery of fixed costs. Again, if the retail rate and net revenue is sufficiently high, the revenue will also more than cover long-term PEV-related capacity, infrastructure, and program costs and ultimately provide downward pressure on average rates for non PEV customers.

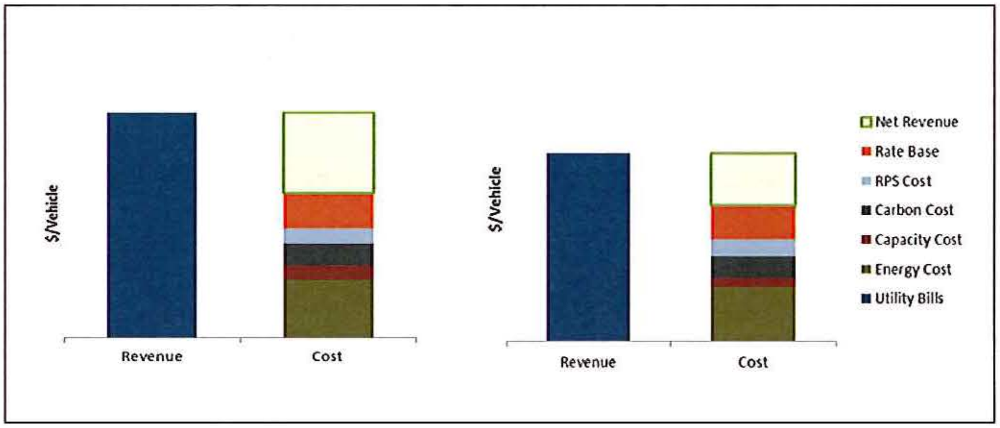


Figure 29. Illustration of Net Revenues without (left) and with (right) TOU Rates

We next consider a generic managed charging case (Figure 2) in which a TOU or other type of dynamic rate encourages off-peak charging when both retail rates and marginal variable costs of delivered energy are lower. Shifting charging to a lower price period reduces the total revenue to the utility, but also reduces the marginal cost of delivered energy and still provides net revenues.

Our analysis suggests that PEV charging rates can be designed to fully recover embedded fixed costs short-run variable costs and long-run marginal (fixed) costs, such that they will provide net revenues and reduce average rates for non-PEV customers. Absent any specific cost treatment, this net revenues will contribute to utility fixed cost recovery and reduce the $/kWh allocation fixed cost in retail rates. This lowers the utility system average rate for all customers. Alternatively a portion of the net revenues can be specifically allocated recover up front utility PEV infrastructure and program costs. In this way PEV programs can be self-funded over the long-term. All PEV related costs are recovered from PEV owners, no costs are imposed on other ratepayers and in fact, retail rates to non-PEV owners in the rate class are reduced.

Examining Figures 1 & 2, the reader will note that the net revenue and contribution to fixed cost recovery for the managed charging case may be greater or lower than in the default case. At first glance, the potential for lower net revenues might appear argue against a managed charging program, but this would be an incorrect conclusion. Managed charging scenario shifts charging to periods when the short-term marginal cost of generation is lower and away from on-peak periods that drive the need for long-term capital investment in new generation and T&D capacity. Critically, in both the default and managed charging cases, PEV load growth can reduce average rates for non-PEV customers, but only in the managed case can utilities also actively reduce the fixed capacity, variable and environmental costs of serving new PEV load. In addition, reducing the cost of PEV charging reduces the cost of PEV ownership for the customer, increasing the economic incentive for PEV adoption. As we show below, a utility sponsored managed charging program will thereby increase net TRC and SCT benefits to the region as a whole relative to the default case.

9.2. Terminology

- **Managed charging**: General, catch-all term for PEV charging that is controlled or incentivized by the utility.
- **VGI charging**: Specific term for dynamic PEV charging that is controlled or incentivized by the utility to mitigate overgeneration and ramp issues associated with higher penetrations of renewable generation.
- **Short-run marginal costs:** variable cost of generating energy and delivering it to the end-user.
- **Long-run marginal costs:** all fixed and variable costs required to generate and deliver energy to the end-user.
- **Embedded fixed costs**: fixed capital costs of existing utility system included in retail rates.
- **Allocation of fixed cost**: the utility fixed costs included in $/kWh retail rates.
- **PEV capacity costs**: new capital investment in system generating and T&D capacity needed to deliver electricity to customer.
- **Utility PEV infrastructure costs**: utility capital costs associated with make-ready, service drop and utility managed or VGI charging to serve customers with PEVs.
- **Customer PEV infrastructure costs**: customer capital costs associated with panel upgrades and charging equipment to charge PEVs.
- **PEV program costs**: all utility overhead, marketing and administrative costs associated with promoting PEV adoption and managed VGI charging.
- **Domestic rate**: retail whole house rate (can be flat, TOU, Tiered).
- **PEV rate**: retail rate for separately or sub-metered PEVs (can be flat, TOU).
- **TOU rate**: retail rate that varies by time-of-use.
- **PEV revenue:** utility retail rate revenue from PEV charging.
- **Net revenue**: PEV revenue minus marginal cost (term to be used in place contribution to margin).

Appendix C: Overgeneration

9.3. How Soon Will Overgeneration Occur?

While there is currently no legislated RPS requirement above 33%, there are several reasons overgeneration is likely to occur at significant levels before 2020:

+ **Renewable procurement is on a trajectory to hit 40% levels**: Even absent a legislative requirement, procurement is on track to exceed 33% in 2020. Project failure in recent solicitations has been much lower than anticipated based on prior experience. Large declines in PV prices have also accelerated procurement outside of IOU RPS solicitations.
+ **Statewide model without transmission constraints**: The production simulation case modeled in REFLEX did not include transmission and associated constraints that would increase overgeneration challenges.
+ **Solar development is concentrated in Southern California**: Solar project development is heavily weighted to Southern California. The South of Path 15 (SP15) zone will reach 40% RPS generation levels and experience overgeneration much sooner than the state as a whole.
+ **Investment Tax Credit**: Most of the solar projects planned are endeavoring to begin operation before the end of 2016 to ensure their eligibility for the Federal Investment Tax Credit.
+ **Production simulation tends to overstate system flexibility**: Production simulation tends to overstate system operational flexibility. E3 took steps to constrain hydro generation and imports to realistic levels. However, the model does assume all fossil generation can be dispatched by the CAISO within operating constraints. In reality, self-scheduled generation may not be readily available for flexible dispatch by the CAISO.

Indeed, negative prices due to overgeneration have already occurred in California, <u>in advance of even 33% RPS</u>. Figures 2-4 show total generation, renewable generation and SP-15 prices for March 6, 2014. Figure 2 shows that the thermal units are ramped down in the middle of the day to accommodate ~3,000 MW of solar generation (Figure 3). This leads to several intervals with negative prices between HE 11 and HE 17 (Figure 4).

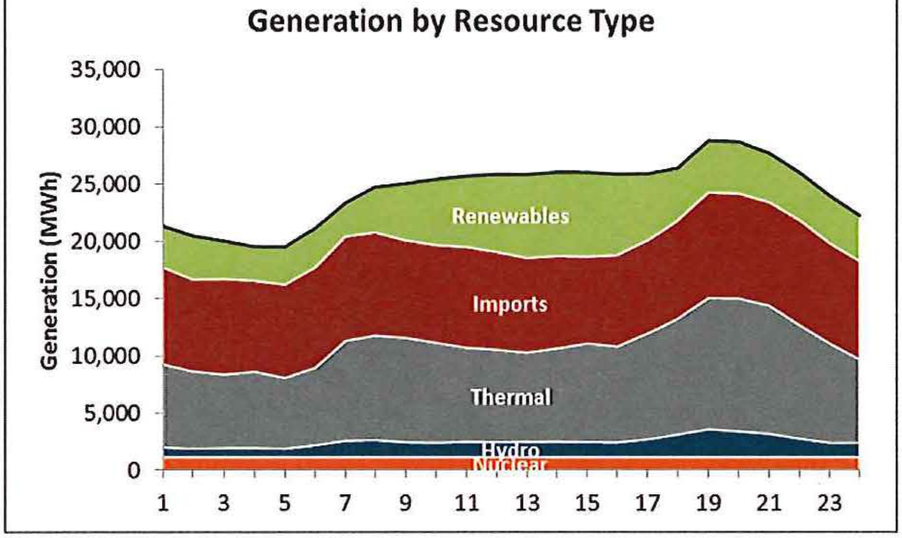


Figure 30: CAISO March 6, 2014 – Generation by resource type

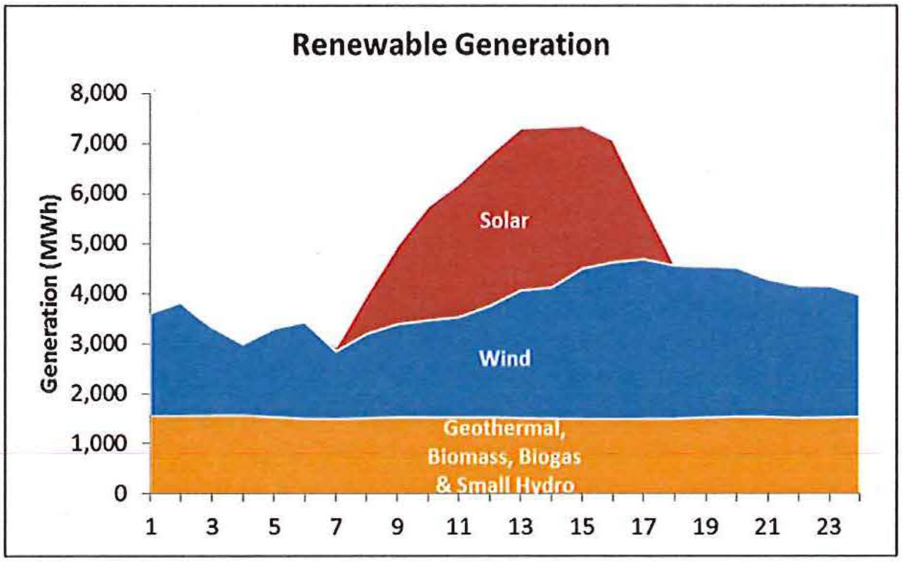


Figure 31: CAISO March 6, 2014 – Renewable generation

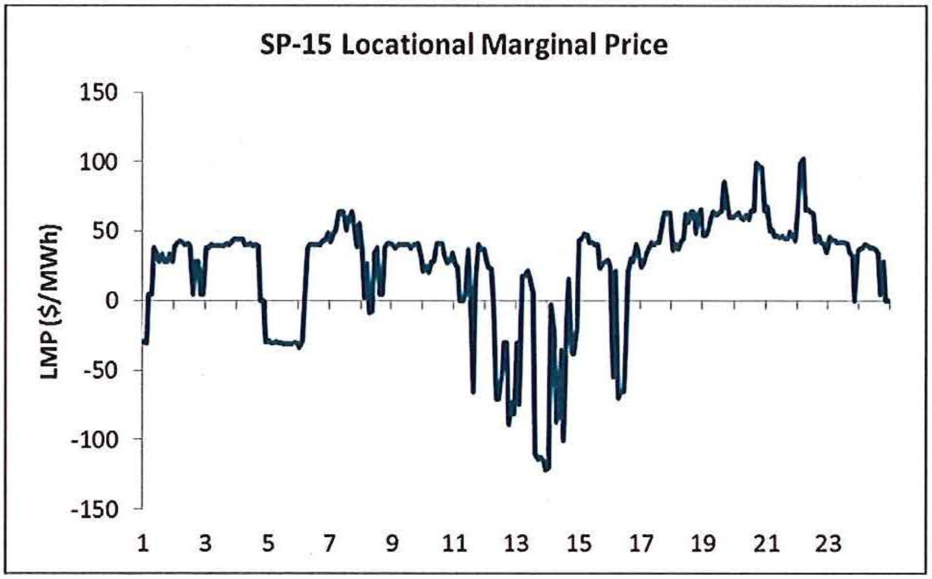


Figure 32: CAISO March 6, 2014 – SP-15 locational marginal price (LMP)

9.4. Value of Avoiding Renewable Curtailment

One solution to overgeneration is to curtail renewable generation. However, curtailment may be an expensive strategy. The immediate cost of curtailment is that the utility cannot use zero emission and marginal cost generation that has already been contracted and paid for. Curtailing renewable generation can also make it more difficult for utilities to achieve RPS and GHG emission reduction goals, which can impose additional costs on the utility.

If utilities have procured resources to meet the RPS with the expectation that a certain level of renewable energy will be delivered from these resources, frequent renewable curtailment may increase the risk of being out of compliance in a given year. There are two strategies for minimizing this risk: 1) the utility can procure additional renewable resources to comply with RPS targets; or 2) the utility can procure resources that provide enough flexibility to ensure that energy from their renewable resources can be delivered (such as energy storage). For a utility, the choice between these two options will depend on the cost of procuring additional renewables versus the cost of procuring flexible resources, as well as the incremental fuel and operating costs associated with each option.

E3 has developed a low and high avoided curtailment value scenario to illustrate the impact of curtailment on system costs and flexible resource value (using methods further described in Appendix A). The low case reflects a scenario where utilities have procured sufficient renewable generation to meet RPS targets, even with anticipated curtailment levels, and do not need to procure additional renewables. Hence, there is no cost to the utility for replacement renewable generation. The high case presumes that utilities must procure additional renewables to meet required RPS targets when curtailment occurs. In the high case, the replacement cost for renewable generation is $125/MWh, reflecting a higher levelized cost for PV that has a lower capacity factor due to its being curtailed on a regular basis. A high cost of curtailment leads to negative values for energy when overgeneration occurs (Figure 9). We refer here to energy value rather than prices because the wholesale market prices for energy will not necessarily reflect the cost of curtailment to the utility.

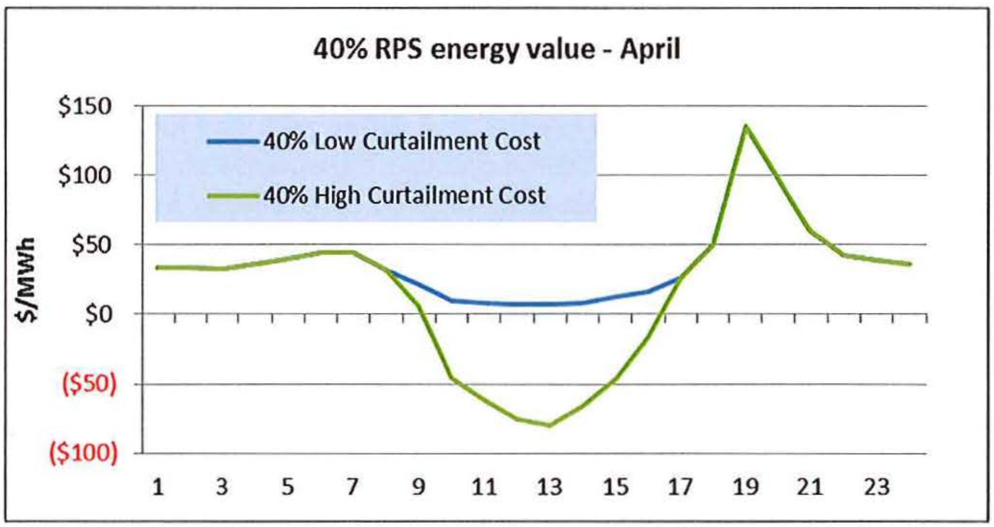


Figure 33: Average hourly energy value in April under 40% RPS scenario with low and high cost of curtailment

Schedule DRI-3

Plug-in Electric Vehicle Deployment in California:
An Economic Jobs Assessment

The California Electric Transportation Coalition commissioned UC Berkeley economist Dr. David Roland-Holst to conduct an economic analysis of the projected job benefits that will be created through the growth of a plug-in electric vehicle market in the state.

Overview

There has been much anecdotally said about green jobs and jobs creation related to alternative-fuel vehicles. The California Electric Transportation Coalition (CalETC) wanted to provide some academic analysis providing deeper insights into the actual economic and jobs impacts of deployment of Plug-in Electric Vehicles (PEVs) in the light-duty sector. Because of the prevalence of personal vehicle use in California, it is hardly surprising that significant technological change will have sizeable and lasting macroeconomic impacts. Generally speaking, the most robust finding of this study is that **statewide economic growth and employment rise with the degree and scope of PEV adoption.** When vehicle owners realize their gas savings, whether households or businesses, those savings are spent on goods and services and the result is higher state economic growth and employment.

Key Findings

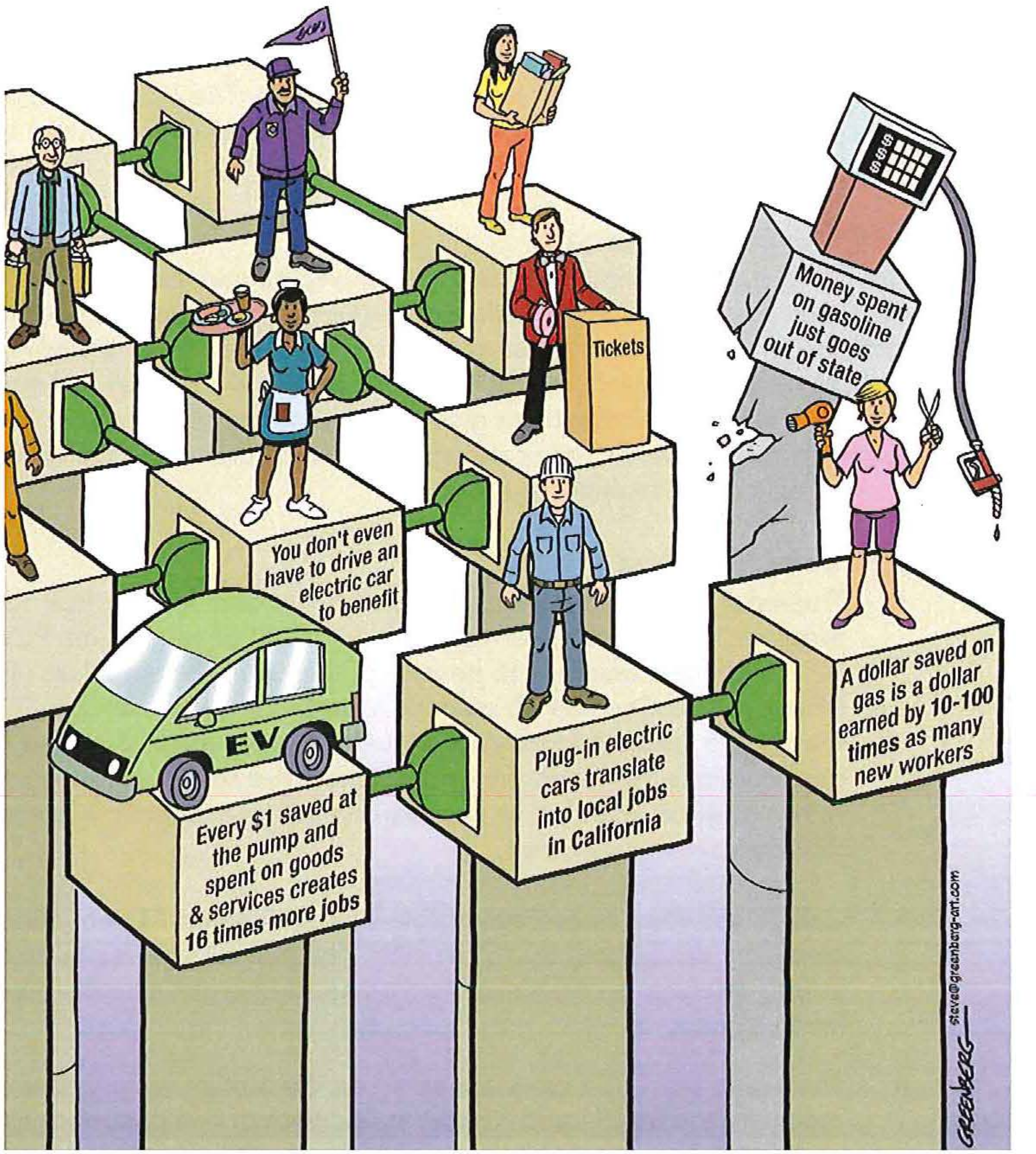
- Electric Vehicles can be a catalyst for economic growth, contributing nearly 100,000 additional jobs by 2030.
- On average, a dollar saved at the gas pump and spent on the other household goods and services creates 16 times more jobs than a dollar spent on refined petroleum product.
- Unlike the fossil fuel supply chain, the majority of new demand financed by PEV efficiency savings goes to in-state services, a source of diverse, bedrock jobs.
- Individual Californians gain from electric car deployment whether they buy an electric car or not. Average real wages and employment increase across the economy and incomes grow faster for low- and middle- income groups than for high-income groups.

How do Plug-in Electric Vehicles Create More Jobs?

PEV adoption stimulates economic growth by reducing the cost of transportation fuel, promoting transportation efficiency and reducing fuel use, thereby saving money for households and businesses. These savings are spent on basic needs and services that create more jobs than the petroleum fuel supply chain.

Plugging in Revs Up the California Economy

■ As California drivers struggle with gas prices well over $4 per gallon, a new economic research report shows that plug-in electric cars can create nearly 100,000 California jobs and provide a powerful local economic stimulus that will benefit people of all incomes.



How do Non-Plug-in Electric Vehicle Owners Plug into Job Benefits?

Detailed analysis of economy-wide impacts show that low, middle and high income households all gain from PEV deployment, regardless of who buys PEVs or their income levels. This is because the spillover effects of gas savings that are spent in the local economy are widespread, creating jobs across nearly every sector of the economy and raising average real wages.

Most of the jobs created by PEV deployment are in service sectors such as healthcare and entertainment. Jobs in these sectors are in-state and at low risk of being outsourced.

Where are the New Jobs Created?

Except for sectors directly linked to the fossil fuel supply chain, transportation fuel savings stimulate job creation across all economic activities where consumers and businesses spend money. This leads to employment growth far beyond "green" sectors and "green-collar" occupational categories. The oil & gas sector does not lose jobs per se, but instead experiences slower job growth overall over a twenty-year timeframe under these scenarios.

What is the PEV Growth Dividend?

The PEV growth dividend arises from a relatively simple mechanism called "expenditure shifting." Household and business fuel savings are spent on new vehicle technology and other consumer goods and services. Because spending on goods and services creates more jobs per dollar of demand than the fossil fuel supply chain, the result of this shift is employment growth. New jobs in turn lead to more spending, with its own induced income and employment stimulus, extending the growth cycle that economists call the multiplier process.

What were the Analytic Assumptions?

- The report considered two scenarios for PEV deployment. PEV 15 scenario assumes 15 percent of the new light-duty fleet of vehicles are PEVs by 2030 and PEV45 scenario assumes 45 percent of the new light-duty fleet of vehicles are PEVs by 2030. The PEV 15 scenario loosely correlates with the ZEV mandate, and the PEV 45 scenario loosely correlates with the state's 2050 goal for greenhouse gas emissions. However, they are not intended to be policy recommendations, rather they are intended to consider the macro-economic impacts of different PEV deployment scenarios.

- CalETC assumed an average gasoline price of about $4 per gallon and an average electricity price about $0.15 per kWh. The fuel cost estimates come from the US Energy Information Administration's Annual Energy Outlook Forecasts, adjusted for California.

- The incremental PEV costs are based on the McKinsey assessment of battery costs and the USEPA and NHTSA assessment of component costs.

- The report looked at deployment of three technologies: Plug-in Hybrid EV with 20 miles all-electric range; Plug-in Hybrid EV with 40 miles all-electric range; and pure Battery Electric Vehicle. For simplification the report assumed equal distribution of these technologies across the new vehicle fleet. The real finding of interest is that the more electric vehicle miles driven the greater the economic benefits.
- The report considered all incentives available in California, including the federal incentives but assume these incentive programs diminish over time and end by 2020.
- The report considered the credit value of the Low Carbon Fuel Standard (LCFS) regulation, which was minimal given our very conservative assumption that the credit value would only be $32.

What is the Berkeley Energy and Resources (BEAR) Model?

CalETC selected Berkeley and the BEAR model because the BEAR model has been thoroughly peer reviewed over many years. The BEAR model is a standard general equilibrium model that considers both direct and indirect effects across the economy, this kind of empirical evidence helps to improve the understanding of the many indirect benefits of PEV deployment.

What is CalETC?

CalETC is a non-profit association promoting economic growth, clean air, fuel diversity and energy independence, and combating climate change through the use of electric transportation. CalETC is committed to the successful introduction and large-scale deployment of all forms of electric transportation including plug-in electric vehicles, transit buses, port electrification, off-road electric vehicles and equipment and rail. With every major auto maker producing or planning to produce PEVs, California is poised to lead in diversifying the transportation fuel sector. CalETC will continue to support all aspects of the transition to electric transportation, working closely with our government, environmental, and industry partners to ensure success.

CalETC California Electric Transportation Coalition
1015 K Street, Suite 200 Sacramento, CA 95814
www.caletc.com

ECONOMIC ANALYSIS

California Low Carbon Fuel Standard

California's Low Carbon Fuel Standard (LCFS) is delivering cleaner fuels, insulation from gas price spikes, cuts in greenhouse gas emissions, and healthier air while our economy continues to grow – and it's helping California maintain its leadership position in the fast-growing clean energy sector.

By spurring greater use of clean alternative fuels and vehicles, the LCFS will result in \$1.4 – \$4.8 billion in societal benefits by 2020 from reduced air pollution and increased energy security.

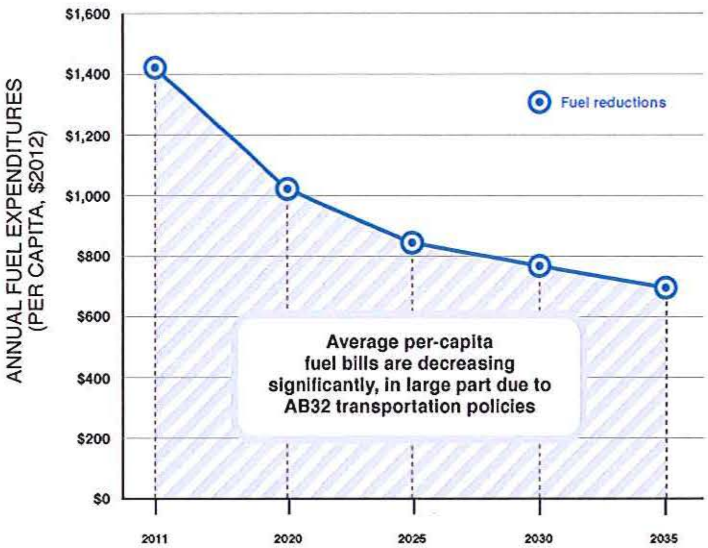
California's economy continues to grow

- A new study on the economic effects of the LCFS – including impacts on jobs, incomes and gross state product – shows the economy will continue to expand.
- Effects on the overall economy are less than one-tenth of one percent – ranging from 0.04% to -0.04%.
- The LCFS could mean 9,100 new jobs for California. This number could be higher, particularly if the state attracts more clean fuel production facilities and technology providers.
- The LCFS has already driven and will continue to drive significant investments in clean alternative fuel production, infrastructure and advanced vehicles – all necessary to continued economic growth.
- While this study only analyzes the economic effects of the LCFS through 2020, experts expect the policy's economic benefits to increase significantly by 2025 and beyond.

Oil industry claims that the LCFS would significantly increase the price of fuel are incorrect

- ICF International, known for its expertise in economic and policy analysis, did the study for a coalition of business groups.
- The potential costs for the petroleum industry to comply with the LCFS translate to \$0.06 to \$0.19 per gallon. As a point of comparison, prices in California have fluctuated by an average range of \$0.75 per gallon for gasoline and \$0.63 for diesel since 2010, largely due to global oil prices, refinery shutdowns and accidents, and seasonal demand.
- The potential value for clean fuel producers will range from \$0.07 to \$1.89 per gallon, depending on how much pollution is reduced by the fuel.
- This study uses transparent assumptions and a widely used economic model.
- An oil industry-sponsored Boston Consulting Group (BCG) study that found dramatic gas price effects of the LCFS was decisively discredited by an expert review panel. The panel said, "We are concerned about some of its assumptions, methodologies and results," and called it "limited," "incomplete," "based on an admittedly unlikely scenario," "pessimistic" and "outdated."

Californians' fuel bills are going down *(per capita)*



While not explicitly analyzed in this study, California's clean energy policies under AB 32, including the LCFS and other transportation-related standards, already are driving down demand for petroleum – cutting fuel bills for Californians. Just as California's energy efficiency policies have saved consumers more than $56 billion on their electricity bills over the last three decades, the state's transportation standards will have similar effects, cutting fuel bills in the future.

Source: ARB and U.S. Energy Information Administration (EIA)

An abundance of alternatives already exists

Clean renewable fuels are available today, and the ICF study shows that we can meet the LCFS in 2020. Each fuel's carbon score is a measure of the greenhouse gas emissions associated with the combination of all the steps in its extraction, production, refining, and final use. The lower the score, the cleaner the fuel.

FUEL SOURCE	Biodiesel, Inedible Corn Oil	Biomethane	Biodiesel, Waste Grease	Renewable Diesel	Ethanol Cellulosic	Renewable Gasoline	Electricity
CARBON SCORE	4	13	14	20	21	25	31
FUEL SOURCE	H_2 Hydrogen	Ethanol, Sugarcane	CNG	LNG	Ethanol	Diesel	Gasoline
CARBON SCORE	39	70	75	80	85	98	99

California Clean Fuels Project

Information in this fact sheet comes from a variety of reputable sources including ICF International's study, California's Low Carbon Fuel Standard: Compliance Outlook and Economic Impacts (April 2014), which was commissioned by a coalition of business groups, including: California Electric Transportation Coalition, Advanced Biofuels Association, California Natural Gas Vehicle Coalition, National Biodiesel Board, Environmental Entrepreneurs and Ceres.

SCHEDULES DRI-6 and DRI-7

THESE DOCUMENTS CONTAIN HIGHLY CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC