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Order Instituting Rulemaking to Examine the Commission's Post-2008 Energy Efficiency Policies, Programs, Evaluation, Measurement and Verification, and Related Issues.	Rulemaking 09-11-014 (Filed November 20, 2009)

ADMINISTRATIVE LAW JUDGE'S RULING SEEKING POST-WORKSHOP COMMENTS ON DEMAND-SIDE COST-EFFECTIVENESS ISSUES

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ADMINISTRATIVE LAW JUDGE'S RULING SEEKING POST-WORKSHOP COMMENTS ON DEMAND-SIDE COST-EFFECTIVENESS ISSUESS

1. Summary

This ruling requests comments in response to two workshops on demand-side program cost-effectiveness that were held by Commission staff on June 28 and June 29, 2012. The workshops were noticed in multiple demand-side program proceedings before the Commission, including Rulemaking (R.) 09-11-014 (energy efficiency), R.10-05-004 (distributed generation), Application (A.) 11-03-001 et al. (demand response), and A.11-05-017 et al. (Energy Savings Assistance and California Alternative Rates for Energy programs).

This ruling presents a series of questions to which parties are invited to respond, compiled from staff pre-workshop questions and party participation in the workshops. In addition, three separate discussion papers on related cost-effectiveness topics are presented as attachments to this ruling. Parties are invited to comment on these attachments as well.

Comments will be due October 1, 2012 with reply comments due on October 10, 2012. Any party to any of the relevant demand-side proceedings listed above may file and serve comments in this proceeding in response to this ruling without the requirement to file a motion for party status in this proceeding.

2. Background

On June 28 and 29, 2012, Commission staff hosted two days of workshops on demand-side cost-effectiveness issues. These workshops were held in response to directives from the Commission in both the energy efficiency and

demand response-related proceedings. For energy efficiency, Decision (D.) 12-05-015 directed the following:

> Commission Staff shall continue their efforts to update cost-effectiveness methodologies. In particular, Staff shall continue to explore issues related to calculation of the discount rate so that improvements may be made to the energy efficiency cost-effectiveness methodology for use in planning future portfolios.[1]

In the context of demand response, D.12-04-045 stated the following: "Commission Staff shall hold one or more workshops after the issuance of this decision to address all deficiencies of the 2010 Cost-Effectiveness Protocols."[2]

In addition, a proposed decision pending in Application (A.) 11-05-017 et al., in the Energy Savings Assistance Program (ESAP) and California Alternative Rates for Energy (CARE) proceeding, addresses numerous aspects of cost-effectiveness related to program delivery to low-income program customers.

Finally, the overall methodologies in use for distributed generation programs are strongly related to the cost-effectiveness approaches used for these other demand-side program areas.

Thus, Commission staff determined that it would be appropriate to hold joint workshops, which were noticed in all relevant proceedings, on aspects of the cost-effectiveness methodologies that are common across all program areas. This culminated in the workshops on June 28 and 29, 2012. The workshop on June 28, 2012 was focused on avoided costs and discount rates, while the workshop on June 29, 2012 was focused on the Standard Practice Manual tests.

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[1] D.12-05-015, Ordering Paragraph 3.

[2] D.12-04-045, Ordering Paragraph 7.

Because of the commonality among the cost-effectiveness issues across all demand-side programs overseen by the Commission, comments on the workshops, certain questions detailed in this ruling, and the attached discussion papers, are being requested for filing only in this proceeding, to minimize duplication of effort in multiple proceedings. By way of this ruling, parties are given notice that the issues addressed in this ruling that are related to demand response, distributed generation, and the ESAP and CARE programs, will be resolved in this rulemaking and not in other proceedings related to those resource areas.

3. Specific Questions to be Addressed in Comments

Below are questions to which parties are invited to respond. These questions are based on the discussion questions posed by Commission staff at the workshops, but also include various comments and proposals made by workshop attendees. Parties may provide general responses to any of the questions, or specific responses to any of particular part of any question. Specific questions to which the investor-owned utilities are required to respond are also noted below.

3.1. Generation-Related Avoided Costs

3.1.1. Resource Balance Year

The resource balance year (RBY) determines when long-run equilibrium generation costs are used. As it is currently calculated, the RBY is the year when capacity and energy markets reflect the marginal cost of new plants, and forecasted supply can no longer meet peak load plus reserves. The current RBYs are different for energy efficiency (2017), demand response (2010), and distributed generation (2015). (Note that the result of the 2010 RBY for demand response is that demand response is only using long-term avoided costs,

whereas energy efficiency and distributed generation use short-term costs until 2015 or 2017, and long-term costs after those years.)

1. When is it appropriate to use long-term avoided costs, and when is it appropriate to use short-term avoided costs? Some workshop participants suggested that demand-side resources should always be compared to long-term avoided costs because capacity is added to the system for a variety of reasons, and comparing demand-side resources to current system conditions undervalues them. Others believe that it is important to look at short-term avoided costs, particularly when deciding to initiate new programs, because the capacity of demand-side resources should not be increased if there are enough supply-side resources to meet demand.

2. Assuming the RBY calculation will continue to be used to distinguish between long- and short-term costs, are there modifications that could be made to the RBY calculation to make it more accurate?

3. Is it appropriate to have different RBYs for different demand-side programs, given the inherent differences among them, or should there be a consistent RBY? Some participants suggested that because different demand-side resources have different characteristics, they should be valued differently.

4. Should the RBY be updated periodically, and, if so, what is an appropriate process? Updates which align with the long-term procurement proceeding are one possibility that was discussed.

3.1.2. Long-Run Resource Costs

The long-run generation capacity cost is based on the cost of a new combustion turbine (CT), while the long-run energy market price is based on the marginal cost of energy production by a combined cycle gas turbine (CCGT). CTs and CCGTs are the most common, least-cost generation units built in California in recent years.

5. Is it still appropriate to model avoided costs on natural gas generation, given that renewable generation will comprise the bulk of new additions? Many participants suggested that even if the bulk of new capacity additions are renewable, that it is still appropriate to base the avoided cost model on gas turbines because they are the least-cost capacity resource.

6. Does the addition of the avoided renewables portfolio standard (RPS) cost properly account for the change in the generation mix? Explain why or why not.

3.1.3. Allocation of Generation Capacity Cost

The generation capacity costs are allocated among 250 hours in the year, in inverse proportion to the amount of generation headroom in each hour. The generation capacity cost is allocated to hours to reflect the likelihood that load reduction or generation addition is needed in that hour. Some parties have suggested allocation among the top 100 hours in the year, return to use of the utilities' Loss of Load Probability models, or development of a more sophisticated model which considers previous events and emergencies and differentiates by utility.

7. Should the allocation method for generation capacity be changed? What are the reasons to use any of the various methods listed above, or another method? (Please focus your answer on concrete suggestions of how to allocate generation capacity costs, rather than criticisms of existing methods.)

3.1.4. Avoided RPS Cost

The avoided RPS cost reflects: (1) the gap between RPS resource costs and conventional resource costs, and (2) the percentage of utility sales that must be supplied via RPS-qualified resources. The renewable cost is based upon the Fairmont competitive renewable energy zone, the most expensive resource bundle that is included in the renewable portfolio in the "33% Reference Case"

modeled by Energy and Environmental Economics (E3). Currently, the percentage of utility sales is a step function that increases with each interim goal.

8. Would changing the step function to a linear function, such that value of RPS energy reductions increases linearly between interim goal years, more accurately reflect the utility procurement costs that will be avoided? Several participants pointed out that use of a linear function would be consistent with the RPS proceeding determinations

3.1.5. Greenhouse Gas (GHG) Emission Costs

Currently, the impact of greenhouse gas reductions is added as an avoided cost stream separate from the avoided energy cost. Beginning in 2013, there will be a carbon price embedded in the wholesale energy prices used to determine the avoided energy cost. This carbon price will reflect the California Air Resources Board's program for achieving carbon reduction goals, but may not represent the actual cost of carbon.

9. After 2013, will there still be a need for an additional GHG avoided cost adder beyond the California carbon allowance price?

10. How do the avoided costs of GHG and RPS affect each other? How should that relationship be accounted for in the Avoided Cost model

3.2. Transmission and Distribution (T&D) Avoided Costs

Currently the T&D avoided costs are based on Commission ratemaking proceedings. These costs vary by climate zone for PG&E, and are utility averages for SCE and SDG&E. **The three large electric utilities (Pacific Gas and Electric, San Diego Gas & Electric, and Southern California Edison) are required to provide the description in question 11 and answer questions 12-14.**

11. Describe in detail the analysis that was used to determine the current T&D avoided costs for your utility.

12. Are the current T&D avoided costs appropriate for demand-side programs? Do they accurately reflect the marginal cost of adding T&D capacity in response to demand? Explain.

13. What are the component costs of the existing avoided T&D costs (e.g., replacing/upgrading poles, wires, hardware, transformers, air switches; building new transmission, sub-transmission, distribution, substations)? To what extent do each of these cost components represent routine replacement, and to what extent are they each load-driven?

14. What is the appropriate method of determining the marginal cost of T&D? Participants suggested using historical data in a multi-variable regression analysis to determine T&D avoided cost functions and then isolating the marginal cost attributable to increased demand. Is this a reasonable approach? Why or why not?

15. What is the appropriate level of disaggregation for T&D avoided costs, and should it differ for energy efficiency, demand response, and distributed generation?

16. The feed-in tariff proceedings have considered identifying specific locations or "hotspots" where distributed generation will provide higher avoided T&D cost savings. Should those location-specific avoided costs be adopted for demand-side programs? Why or why not?

3.3. Discount Rate

Currently, the discount rate applied in cost-effectiveness tests is the after-tax weighted average cost of capital (WACC). Other suggested discount rates include the before-tax WACC, a societal discount rate, and a consumer discount rate.

17. Assuming that the WACC will continue to be used for at least some, although not necessarily all, cost-effectiveness analyses of demand-side resources, is the after-tax WACC the appropriate discount rate to use or would the before-tax WACC be more appropriate?

18. Should a societal discount rate be considered for any part of the current cost-effectiveness analysis? When, if ever, is it appropriate to use a societal discount rate?

19. Should a consumer discount rate be considered for any part of the current cost-effectiveness analysis? When, if ever, is it appropriate to use a consumer discount rate? How should the consumer discount rate be determined? How many different consumer discount rates (for different types of consumers) would be needed?

20. Some participants suggested using different discount rates for different cost-effectiveness tests, or different discount rates for different cost-effectiveness inputs. Is this appropriate, and is this feasible? How?

3.4. Updates

To determine the impact of regular data inputs, please consider the following question:

21. Should the input data be updated regularly?

22. What process and timeline should be implemented to allow parties and the Commission to examine the input data before updates are adopted?

3.5. Consistency Across Demand-Side Proceedings

To determine which differences are necessary in the cost-effectiveness framework to appropriately address demand-side (energy efficiency, demand response, distributed generation, permanent load shifting, and the Energy Savings Assistance) programs, please consider the following questions:

23. What relationship should the existing demand-side cost-effectiveness efforts have to one another? Is it feasible to have one basic framework for all demand-side programs, with only minor variations or additions for each resource, or should separate methods and models continue to be developed for each resource?

24. Should the Commission continue to separately address cost-effectiveness for each demand-side resource in different proceedings, or can consistency only be accomplished if cost-effectiveness is addressed in one proceeding? What are the pros and cons of having an over-arching demand-side cost-effectiveness proceeding? Are there any regulatory barriers or policy concerns?

3.6. Standard Practice Manual Tests

3.6.1. Criticisms of the Total Resource Cost (TRC) Test

In recent years, the Commission has relied heavily on the TRC to determine whether demand-side programs are cost-effective; many jurisdictions in the U.S. do the same. Because the TRC measures costs and benefits from the perspective of utilities and their customers, it includes participant costs as an input. Critics of the TRC claim that participant costs are being overestimated, because those costs are very often incurred because customers want to receive non-energy benefits (NEBs), in addition to energy savings. Three remedies have been suggested to correct this perceived asymmetry of costs and benefits: (1) either replacing or putting more focus on the Program Administrator Cost (PAC) test, instead of the TRC; (2) ensuring that the participant costs are adjusted to remove costs associated with NEBs; or (3) adding NEBs to the TRC.

25. What are the pros and cons of using the PAC, rather than the TRC, as the primary test of cost-effectiveness? Option (2) in question 24 above leads to an "energy only" TRC, where non-energy impacts are excluded, whereas option (3) above leads to a TRC which includes non-energy impacts. Which is more appropriate for the TRC test?

26. Currently, in energy efficiency cost-effectiveness calculations, the effect of NEBs is intended to be minimized by applying a net-to-gross ratio to the participant costs. Does the net-to-gross formulation provide an accurate accounting of participant costs?

Should a similar process be used for demand response and/or distributed generation?

27. In the demand response context, participant costs include value of service lost and transaction costs. Are these costs relevant for any other demand-side resources?

28. Assuming NEBs were added to the TRC (or another cost-effectiveness test), is the NEB research that has been done in the low income proceeding on participant and utility NEBs applicable to other resources? If so, which NEBs should be included? If not, how should the value of NEBs be determined for the cost-effectiveness framework?

29. Are there societal NEBs (beyond GHGs) that you believe should be fit into the cost-effectiveness framework? If so, how (i.e., via which test or tests) should they be handled?

3.6.2. Other TRC Issues

30. Are there cost and benefits inputs (other than participant costs) to the TRC that should be updated, redefined, or calculated differently? Are current methodologies over- or under-estimating some benefits and costs? If so, which ones?

31. Are there any other impacts, such as the rebound effect or long-term impacts, that need to be accounted for in the TRC? (Note that spillover and market transformation effects are being addressed in other proceedings.)

32. Many parties in the energy efficiency proceeding have suggested that the avoided costs of embedded energy in water be added to the TRC. Should the Commission add the avoided costs of embedded energy in water to the TRC, and, if so, what is the best approach?

3.6.3. Other Cost-Effectiveness Tests

33. What is the Ratepayer Impact Measure (RIM) test useful for? How should it be weighted in cost-effectiveness analysis? Does the current RIM formula need to be revised to accurately reflect programs involving long-term, capital-intensive, customer funded projects (e.g., permanent load shifting)?

34. Would additional cost-effectiveness tests, or alternative forms of the existing tests (e.g., a societal TRC test), be useful? Explain.

35. Would a societal TRC test (i.e., a TRC which included non-energy costs and benefits) be useful for measuring the value of demand-side programs? If there was a societal TRC, how should it be used to determine the program design and the content of the portfolio of demand-side programs?

3.6.4. Using the Cost-Effectiveness Tests

36. In past proceedings, the Commission has relied primarily on the TRC to determine the cost-effectiveness of demand-side programs. Should the Commission continue to rely primarily on the TRC, or could the method of determining program offerings, program design, incentive levels, or other decisions about demand-side programs be improved by giving more prominence to different tests or other methods? For example, workshop participants suggested that the Commission pay more attention to the RIM test; that different tests be used at different levels (i.e., measure, program, and portfolio); that having positive net benefits according to the PAC be used as a minimum criterion of cost-effectiveness; and that the various tests be "weighted."

4. Comments Requested on Attachments A-C

In addition to the questions above, this ruling includes three discussion papers related to cost-effectiveness, as follows:

Attachment A: Energy Efficiency Avoided Costs 2011 Update, authored by Energy and Environmental Economics (E3) under contract to the Commission.

Attachment B: Use of Before- and After-Tax Discount Rates in Energy Efficiency Cost-Effectiveness Evaluations, also authored by E3.

Attachment C: Addressing Non-Energy Benefits in the Cost-Effectiveness Framework, authored by Commission staff, based on research provided by Ed Vine of the Lawrence Berkeley National Laboratory.

Interested parties in any of the relevant demand-side proceedings are invited to provide comments and reply comments on any or all of these attachments, on the same timeframe as the other comments requested in Section 3 above.

IT IS RULED that:

1. Interested parties in Rulemaking (R.) 09-11-014 or R.10-05-004, or Applications (A.) 11-03-001 et al. or A.11-05-017 et al., may file and serve comments on the questions posed in Section 3 of this ruling, any aspect of the discussion in the June 28, and 29, 2012 cost-effectiveness workshops, and/or the discussion papers in Attachments A-C, by no later than October 1, 2012. Parties shall file and serve such comments in R.09-11-014.

2. Interested parties in R.09-11-014 or R.10-05-004, or A.11-03-001 et al. or A.11-05-017 et al., may file and serve reply comments on the questions posed in Section 3 of this ruling, any aspect of the discussion in the June 28, and 29, 2012 cost-effectiveness workshops, and/or the discussion papers in Attachments A-C, in response to other parties' comments filed and served no later than October 1, 2012, by no later than October 10, 2012. Parties shall file and serve such reply comments in R.09-11-014.

3. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company must file and serve responses to questions 11-14 in Section 3 of this ruling, and may file and serve responses to other questions in Section 3, any aspect of the discussion in the June 28, and 29, 2012 cost-effectiveness workshops, and/or the discussion papers in Attachments A-C, by no later than October 1, 2012. Utility comments shall be filed and served in R.09-11-014.

4. Any party to R.10-05-004, or A.11-03-001 et al. or A.11-05-017 et al., timely filing and serving comments in response to this ruling shall automatically become a party to this proceeding without the requirement for a separate motion for party status.

5. This ruling shall be served on all parties in R.09-11-014 and R.10-05-004, as well as A.11-03-001 et al. and A.11-05-017 et al.

6. By way of service of this ruling in R. 09-11-014 and R.10-05-004, as well as A.11-03-001 et al. and A.11-05-017 et al., parties to all of these proceedings are put on notice that the cost-effectiveness issues addressed in this ruling that are related to demand response, distributed generation, the Energy Savings Assistance Program and the California Alternative Rates for Energy program, will be resolved in this proceeding (R.09-11-014).

Dated August 14, 2012, at San Francisco, California.

/s/ JULIE A. FITCH
Julie A. Fitch
Administrative Law Judge

ATTACHMENT A

Energy Efficiency Avoided Costs 2011 Update

ATTACHMENT A

Energy and Environmental Economics, Inc

Energy Efficiency Avoided Costs 2011 Update

Brian Horii, Eric Cutter
December 19, 2011

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Overview

This technical memo describes the inputs and methods used to update the avoided costs for energy efficiency cost-effectiveness valuation for the 2014 through 2016 program cycle. In the past, such updates have been performed quickly by changing a minimal set of input values and leaving the extant (circa 2004) avoided cost methodology unchanged. In the years since the EE avoided cost methodology was adopted, however, numerous methodology changes and enhancements have occurred in other CPUC proceedings. Specifically, Energy and Environmental Economics Inc's (E3) work on the California Solar Initiative (CSI) and Demand Response (DR) proceedings have produced numerous methodology enhancements that have been incorporated into this EE avoided cost update.

The major methodology changes affect the forecast of electricity generation energy and capacity, and are listed below.

Updates consistent with the SGIP and CSI Cost-effectiveness Evaluation[1]

1. Explicitly calculate capacity value based on CT net capacity cost
2. Set energy price at the "make whole" level for a CCGT unit
3. Replace the use of PX market hourly shapes with 2010 MRTU hourly shapes
4. Move the resource balance year (the year when the avoided costs are based on sustaining new CT and CCGT units in the market) to 2017

[1]See D. 09-08-026, CSI Cost-effectiveness Report (http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm) and CPUC SGIP Cost-effectiveness of Distributed Generation Technologies (http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/)

5. Update the ancillary service value to reflect 2010 markets

6. Remove the energy market multiplier

7. Update CO2 values to Synapse Consulting mid-case forecast

Updates based on the DR Cost-effectiveness Protocols[2]

1. Model generator performance with monthly performance adjustment factors based on historical weather

2. Adjust avoided capacity value to reflect the $/kW-yr value of produced capacity, rather than nameplate capacity, under hot ambient temperature conditions.

3. Update allocation of capacity value to be based on 4 years of historical load and temperature data

Other major updates to the 2011 avoided costs are:

1. T&D method left unchanged, but T&D avoided cost levels updated to reflect more recent utility filings

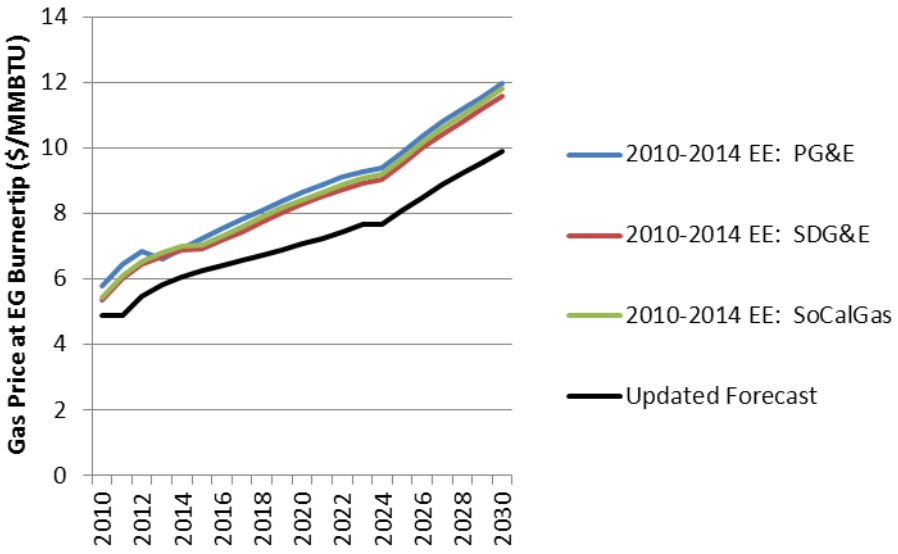
2. Gas forecast lowered to reflect market conditions at the time of the DR proceeding (December 2010.) The gas forecast affects both electricity cost determination and gas avoided procurement costs.

[2] See D. 10-12-024

Natural Gas Avoided Cost Updates

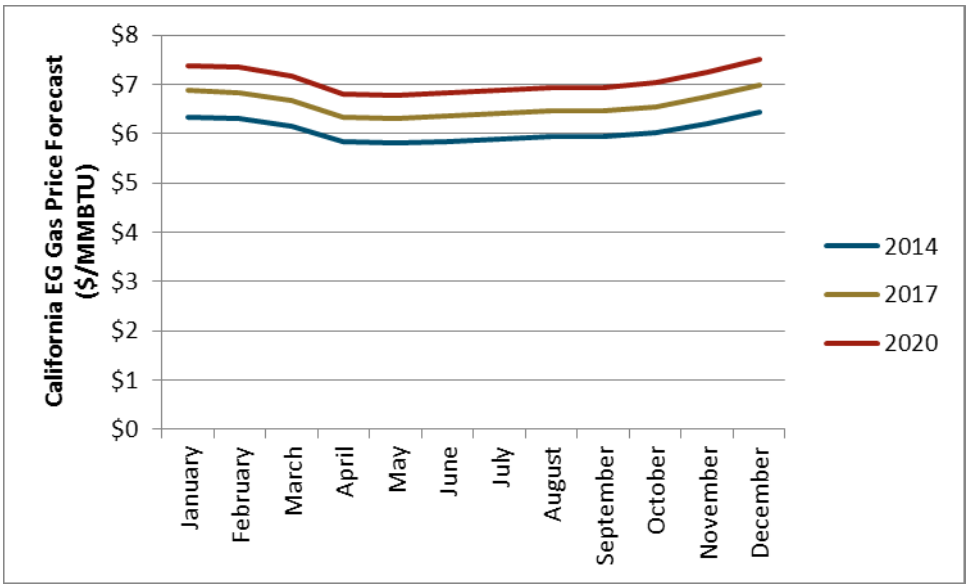
E3 has constructed the natural gas commodity price forecast using NYMEX Henry Hub futures through 2022 updated in December 2010, plus average basis differentials for delivery from Henry Hub to the utility local transmission system (trading through 2015).. After 2022, an average of three fundament price forecasts is used. The forecast methodology for annual natural gas prices is the same as that was used in the CPUC 2009 Market Price Referent (MPR) Update proceeding (the most recent MPR update available at the time). The annual commodity price forecast for each utility service territory is shown in Figure 1.

Figure 1. Natural gas price forecast



This 2011 update augments the MPR's forecast methodology to incorporate expected monthly trends in gas prices—commodity prices tend to rise in the winter when demand for gas as a heating fuel increases. The monthly price profiles are based on the monthly natural gas futures prices used to develop the price forecast. Figure 2 shows three snapshots of the monthly shape of the natural gas price forecast.

Figure 2. Snapshot of monthly gas price forecast shapes for 2014, 2017, and 2020.



For the avoided costs used to evaluate natural gas EE reductions, the following costs are added to the commodity cost.

- compression (0.39%),
- losses and unaccounted for (1.37%),
- marginal transmission and delivery costs (varies by utility),
- NOX and CO2 ($5.82/lb and $15.37/short ton in 2012. Both escalate annually)

Of these additional cost items, only the CO2 $/short ton value has been updated. The cost of CO2 is discussed in more detail in the electricity avoided cost section of this memo.

For the natural gas price for electricity generators, which is an input into the estimation of electricity avoided costs, tariff charges for delivery to the generators (Utility Electric Generation or UEG) are added to the commodity price. The tariffs and calculations used are also from the 2009 MPR update, updated with the tariffs applicable in 2010.

Overview of Electricity Avoided Cost Components

This 2011 avoided cost update incorporates significant methodology changes relative to the avoided cost methodology used for EE since 2006. The most significant change is that rather than use one, all-in avoided cost of electricity and the PX market price shape, energy and capacity prices are calculated and allocated separately. Also, two additional avoided costs are added for a total of six avoided cost components. This section provides a brief overview of the electricity avoided cost components and their contribution to the total electricity avoided costs. This is followed by detailed discussions of the updates for each component in the subsequent sections.

The avoided cost used for electricity energy efficiency evaluation is calculated as the sum of six components shown in Table 1.

Table 1. Components of electricity avoided cost

Component	Description
Generation Energy	Estimate of hourly wholesale value of energy
Generation Capacity	The costs of building new generation capacity to meet system peak loads
Ancillary Services	The marginal costs of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet peak loads
Environment	The cost of carbon dioxide emissions associated with the marginal generating resource
Avoided RPS	The reduced purchases of renewable generation at above-market prices required to meet an RPS standard due to a reduction in retail loads

Each of these avoided costs is must be determined for every hour of the year. The hourly granularity is obtained by shaping forecasts of the average value of each component with historical day-ahead and real-time energy prices and actual system loads reported by CAISO's MRTU system for 2010; Table 2 summarizes the methodology applied to each component to develop this level of granularity.

Table 2. Summary of methodology for electricity avoided cost component forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	Forward market prices and the $/kWh fixed and variable operating costs of a CCGT.	Historical hourly day-ahead market price shapes from MRTU OASIS
Generation Capacity	Residual capacity value a new simple-cycle combustion turbine	Top 250 CAISO hourly system loads.
Ancillary Services	Percentage of Generation Energy value	Directly linked with energy shape
T&D Capacity	Marginal transmission and distribution costs from utility ratemaking filings.	Hourly temperature data
Environment	Synapse Mid-Level carbon forecast developed for use in electricity sector IRPs	Directly linked with energy shape with bounds on the maximum and minimum hourly value
Avoided RPS	Cost of a marginal renewable resource less the energy market and capacity value associated with that resource	Flat across all hours

Figure 3, below, shows a three-day snapshot of the avoided costs, broken out by component, in Climate Zone 13. As shown, the cost of providing an additional unit of electricity is significantly higher in the summer afternoons than in the very early morning hours. This chart also shows

the relative magnitude of different components in this region in the summer for these days. The highest peaks of total cost shown in Figure 3 of over $2,500/MWh are driven primarily by the allocation of generation and T&D capacity to the peak hours (because of high demand in those hours), but also by higher energy market prices during the middle of the day.

Figure 3. Three-day snapshot of energy values in CZ13 in 2017

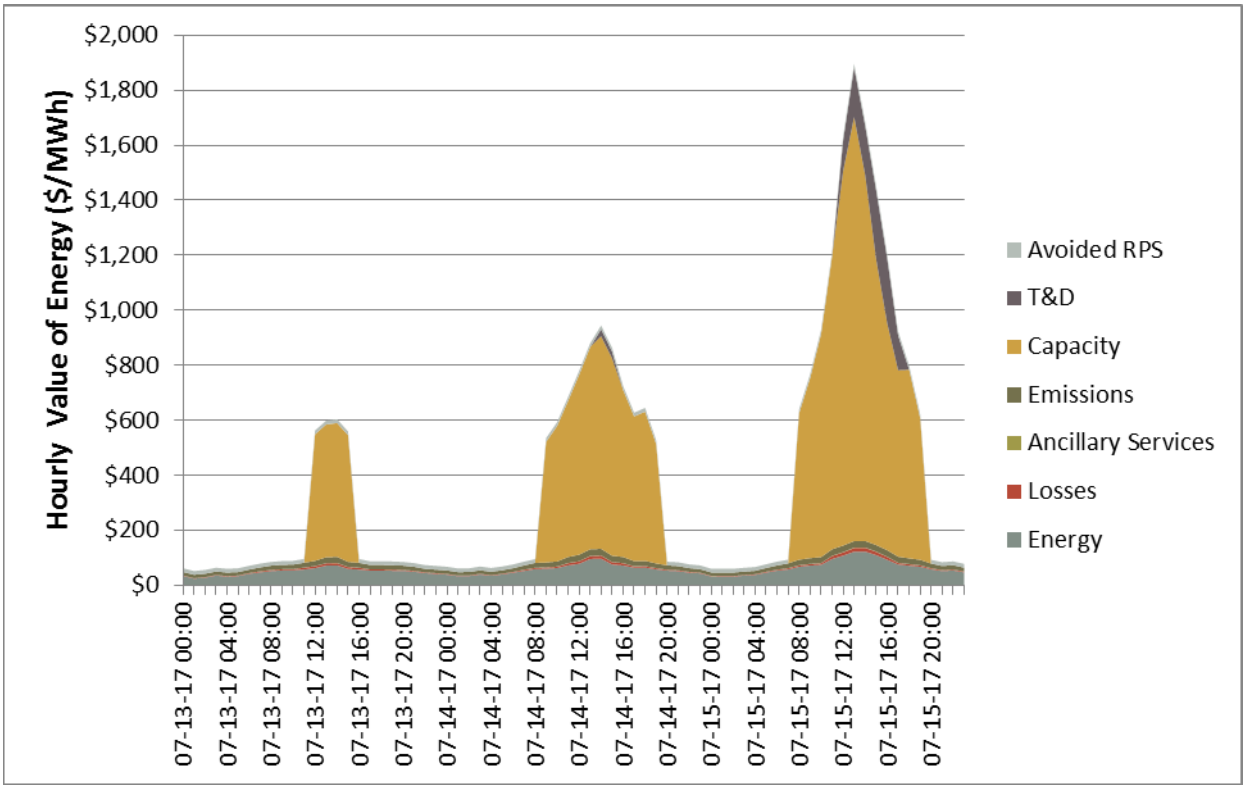


Figure 4 shows average monthly value of electricity reductions, revealing the seasonal characteristics of the avoided costs. The energy component dips in the spring, reflecting low energy prices due to increased hydro supplies and imports from the Northwest; and peaks in the summer months when demand for electricity is highest. The value of capacity—both generation and T&D—is concentrated in the summer months and results in significantly more value on average in these months.

Figure 4. Average monthly avoided cost in CZ13 in 2017

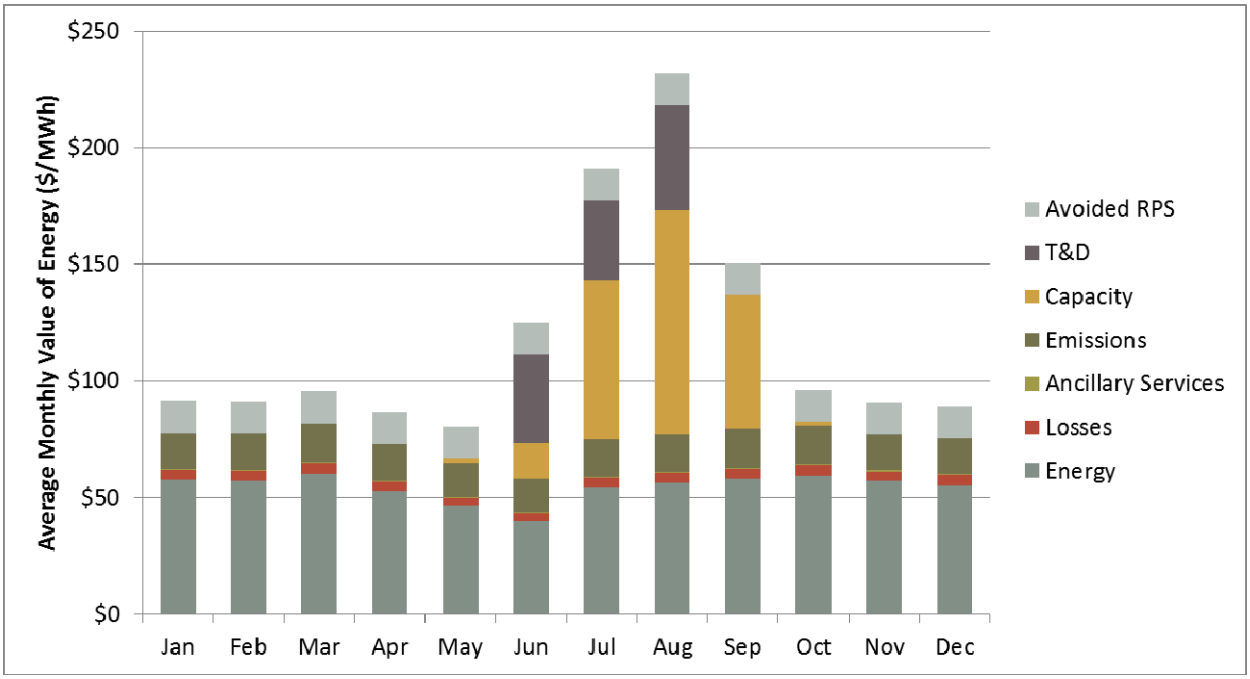
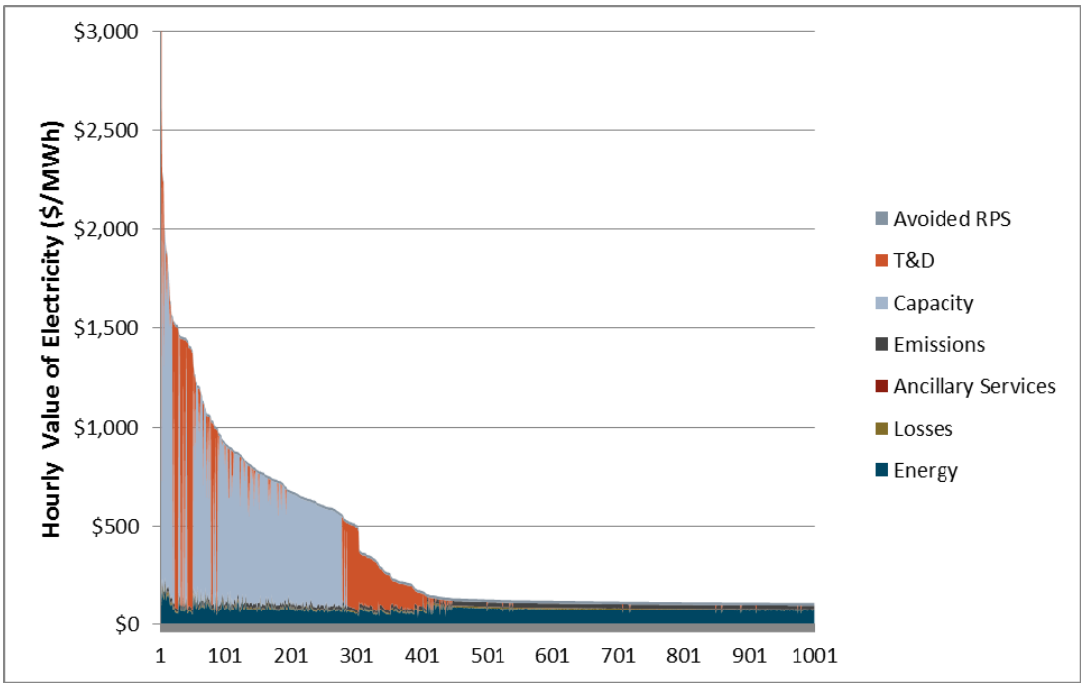


Figure 5 shows the components of value for the highest value hours in sorted order of cost. This chart shows the relative contribution to the highest hours of the year by component. Note that most of the high cost hours occur in approximately the top 200 to 400 hours—this is because most of the value associated with capacity is concentrated in a limited number of hours. While the timing and magnitude of these high costs differ by climate zone, the concentration of value in the high load hours is a characteristic of the avoided costs in all of California.

Figure 5. Price duration curve showing top 1,000 hours for CZ13 in 2017



Avoided Cost Methodology

Generation Energy

The treatment of generation avoided costs received substantial methodology updates in the CSI and DR proceedings. Those methodology updates have been incorporated into this 2011 update. The differences between the extant 2004-2012 energy efficiency approach and the updated generation avoided cost methodology are summarized below.

2004-2012 Energy Efficiency Approach: The extant method uses a long-run cost of generation starting in 2008. Long-run generation cost is the all-in cost of a CCGT running 92% of the year (based on the same assumptions used to calculate the Market Price Referent (MPR)). The all-in cost is the total fuel, O&M, and levelized capital costs of the new generator. This all-in cost is then shaped to an hourly profile based on the California Power Exchange day-ahead market prices from the "functional" periods of that market (1998-1999)[3]. The 2010-2012 avoided costs also include a CO2 emission adder of $30 per short ton.

CSI and DR Avoided Cost Update: The CSI and DR proceedings make a fundamental methodology change by moving away from the prior PX market structure modeled in the EE avoided costs. In the PX market, capacity value was included in the hourly market prices. With the advent of the Resource Adequacy payments and discussions of a capacity market, it became important to explicitly model capacity value separate from energy market value. The CSI and DR avoided cost models calculate explicit capacity

[3] While the extant method uses generator performance and costs and long-run gas forecasts from the MPR, it differs from the MPR in using the Power Exchange hourly energy price profile. The MPR uses hourly shapes based on utility energy market simulations.

and energy values, resulting in total generation avoided costs that are more concentrated in the peak hours of the year. Other substantial updates include the replacement of the PX market shapes with 2010 MRTU market data, the use of the Synapse Consulting mid-case forecast of CO2 costs, and the addition of Renewable Portfolio Standard (RPS) avoided costs. Capital costs for a CT are taken from the most recent CAISO Annual Market Issues and Performance Report (which in turn are based on the CEC Cost of Generation Report). Capital Costs for a CCGT are taken from the most recently adopted MPR update. A book life of 20 years is assumed for both the CT and CCGT. This assumption is consistent with the MPR proceeding, the CEC Cost of Generation Report, the Northwest Electric Power and Conservation Plan, the Lazzard Levelized Cost of Energy Analysis and both the PJM and NYISO Cost of New Entry (CONE) analyses. Independent Power Producer cost of capital and financing assumptions are used. The CPUC has approved the construction or purchase of several natural gas plants by utilities in recent years. However the primary intended mechanism for meeting resource adequacy requirements is bilateral agreements between utilities and independent third-parties. Several modest changes to the calculation of the capital and operating costs were made in the DR Cost-Effectiveness Protocol proceedings in late 2010 and early 2011 in response to party comments. These include making the tax and insurance assumptions consistent with the MPR, including the use of the Domestic Manufacturing Tax Credit.

Determination of energy market values

The updated avoided energy costs are developed using a method similar to what was used for CSI. In years prior to resource balance, the average energy cost is based on the NYMEX market price forecast (available through 2014 for the update in 2010). For the period after the available forward market prices, the method interpolates between the last available NYMEX market price and the long-run energy market price. The long-run energy market price is used for the resource balance and all subsequent years.

The annual long-run energy market price is set so that the CCGT's energy market revenues plus the capacity market payment equal the fixed and variable costs of the CCGT (i.e.: the CCGT is made whole). The long-run energy market price begins with the 2010 MRTU day-ahead market price escalated by the natural gas burner tip forecast. This reflects the assumption that CAISO Day Ahead energy prices will represent the electricity procurement costs avoided by utilities. The energy market price is then increased or decreased with an energy market calibration factor so that the CCGT is made whole. The energy market calibration factor is applied to both 1) the real-time market prices used to determine CT energy revenues and the value of capacity, and 2) the day-ahead energy market used to determine CCGT energy revenues. This creates a feedback effect between the energy and capacity avoided costs. The feedback effect is illustrated with the following example.

> *Assume that the CCGT would collect more revenue through the capacity and energy markets than is needed to cover its costs. The methodology decreases the calibration factor to decrease the day-ahead energy market prices and market revenues to make the CCGT whole. To keep the real-time and day-ahead markets in sync, the methodology also would decrease the real-time energy market prices by the calibration factor. The decrease in real-time energy market prices would result in lower net revenues for a CT, and therefore raise the value of capacity (as higher capacity payment revenue is needed to incent a new CT to build). When we re-examine the CCGT, the raised value of capacity results in the CCGT collecting excess revenues, so the calibration factor needs to be decreased more, and the process repeats*[4].

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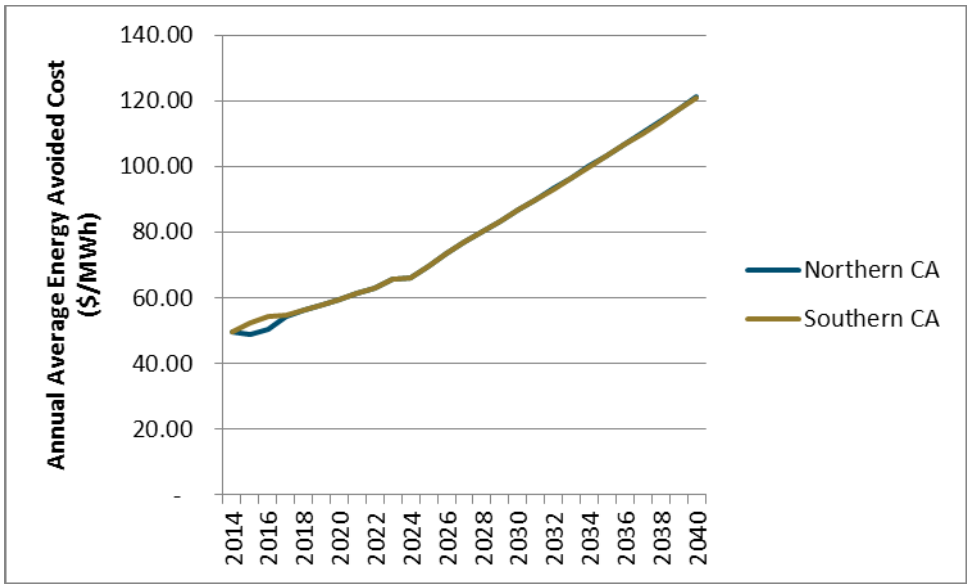
[4] The actual process steps for determining the calibration factor for each year (and therefore the real-time and day-ahead market prices) are listed below.

1. Set the annual day-ahead energy price at the 2010 level increased by the percentage change in the forecast annual gas burner tip price.
2. Set the energy market calibration factor to 100%
3. Multiply (1) by (2) to yield the adjusted annual day-ahead price

Figure 6: Annual Average Energy Avoided Costs



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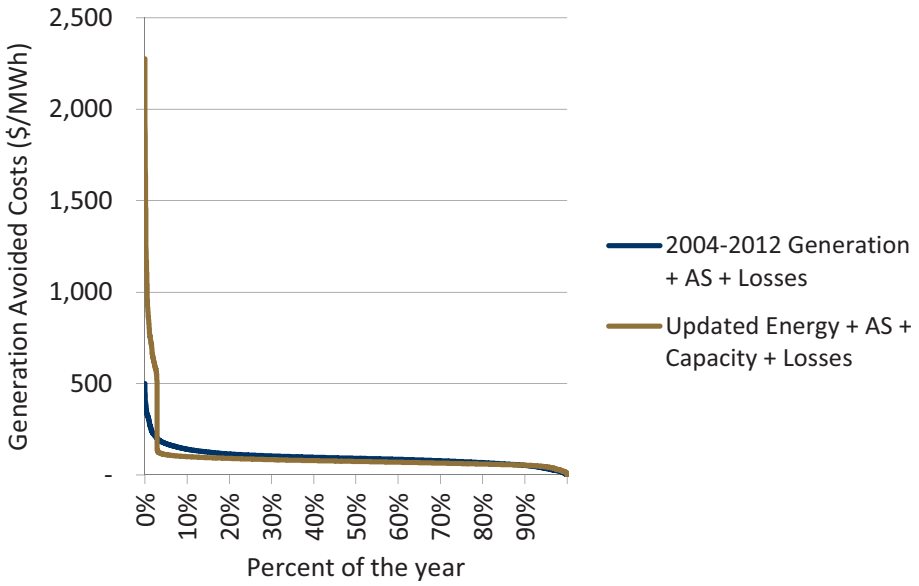
4. Calculate capacity cost
    a. Multiply the real-time 2010 hourly price shape by the adjusted annual day ahead price
    b. Dispatch a new CT against the hourly prices in Northern and Southern CA from 4a to determine real time dispatch revenue in Northern and Southern CA (Figure 6)
    c. Calculate ancillary service revenues as 7.6% of the real-time dispatch revenue
    d. Capacity value is the net capacity cost. Net capacity cost = the levelized cost of the new CT plus fuel and O&M costs less
    e. Adjust capacity value ($/kW-yr) to reflect degraded output at system peak weather conditions (Figure 10)
    f. Set the capacity value at the average of Northern and Southern CA capacity values
5. Calculate energy cost
    a. Multiply the day-ahead 2010 hourly price shape by the adjusted annual day ahead price
    b. Dispatch a new CCGT against the hourly prices from to determine the day-ahead dispatch revenue (
    c. Calculate the excess (deficient) margin of a CCGT unit as the levelized cost of a new CCGT plus fuel and O&M costs less (adjusted for CCGT output degradation)
6. If there is excess or deficient margin for the CCGT unit, decrease or increase the energy market calibration factor, and repeat from step.

Hourly Shaping of Energy Costs

As with the 2004-2012 energy efficiency avoided cost methodology, the annual energy avoided costs are converted to hourly values by multiplying the annual value by 8760 hourly market shapes. For the 2004-2012 methodology, hourly PX prices were used. For this update, the hourly shape is derived from day-ahead LMPs at load-aggregation points in northern and southern California obtained from the California ISO's MRTU OASIS. In order to account for the effects of historical volatility in the spot market for natural gas, the hourly market prices are adjusted by the average daily gas price in California. The resulting hourly market heat rate curve is integrated into the avoided cost calculator, where, in combination with a monthly natural gas price forecast, it yields an hourly shape for wholesale market energy prices in California.

Total energy and capacity avoided costs are shown in Figure 7. The avoided costs are shown in descending order. Whereas the 2004-2012 EE cost shape is based on the previous PX market hourly prices, the updated cost shape reflects 1) the allocation of capacity costs to the top 250 system load level hours in the year and 2) the shaping of the energy costs based on 2010 MRTU California wholesale market information.

Figure 7: Hourly Generation Avoided Costs for 2017



Note that the 2004-2014 Generation avoided costs reflect the cost assumptions used for the current 2010-2014 E3 Calculators. The Updated avoided costs reflect new input values such as lower natural gas prices. The comparison shows current vs updated avoided costs. If the existing method were updated with the same input values as the updated forecast, the avoided costs would be lower than those shown in the figure.

Generation Capacity

Generation resource balance year

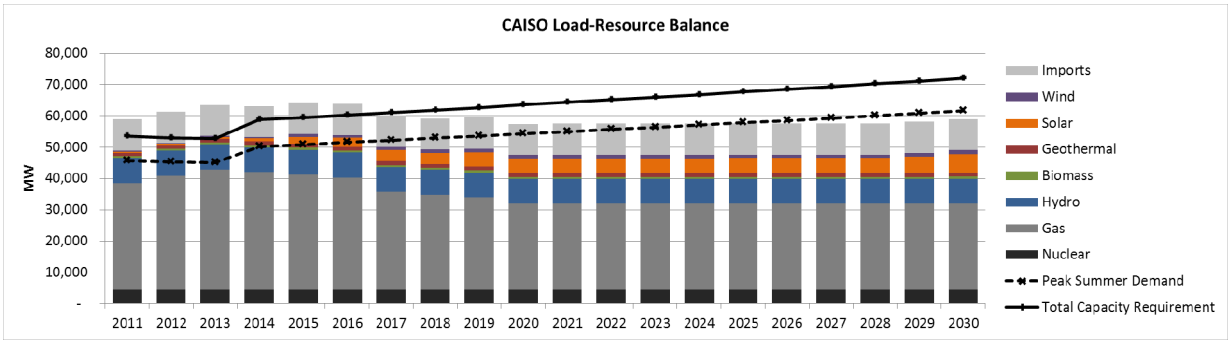
Generation capacity for this update is calculated using the DR method, updated with 2010 input data. The method assumes that in the resource balance year and beyond, the value of capacity will equal the fixed cost of a new CT less the net revenues that the CT would attain from the selling to the real-time energy and ancillary service markets (residual capacity value). In the years prior to resource balance, the capacity value is interpolated from the resource adequacy value of $28.07/kW-yr in 2008 to the residual capacity value in the resource balance year.

The resource balance year determines when the capacity and energy markets will reflect the full cost of new plants. The extant EE calculator uses a resource balance year of 2008 (based on projections performed in 2004), while the CSI proceeding used a resource balance year of 2015.

In the DR proceeding, the CPUC directed that the full residual capacity of a CT be used to quantify the capacity value of DR, so no resource balance year adjustment was made.

E3 has set the resource balance year to reflect the recent Joint IOU July 1, 2011 filing in the LTPP proceeding (R.10-05-006 track 1), E3 uses a resource balance year of 2017 for the updated EE avoided costs. 2017 reflects the middle load trajectory with 10,000 MW of imports, no demand response, and no incremental EE or combined heat and power after 2013. The 10,000 MW import assumption is lower than the CPUC's recommended value of 17,000 MW. However, E3 believes that 10,000 MW is a more appropriate value to use for this analysis as it is more consistent with actual import amounts at the time of the California system peak conditions.

Figure 8. Evaluation of resource balance year



CT dispatch

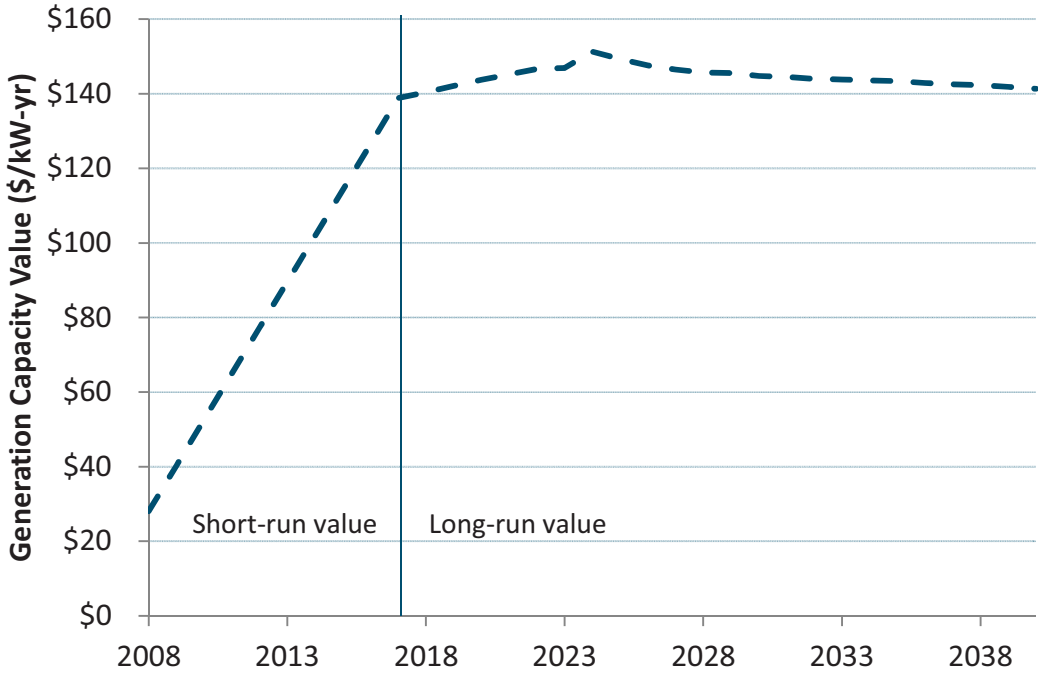
To determine the long-run value of capacity, the avoided cost model performs an hourly dispatch of a new CT to determine energy market net revenues. The CT's net margin is calculated assuming that the unit dispatches at full capacity in each hour that the real-time price exceeds its operating cost (the sum of fuel costs and variable O&M) plus a bid adder of 10%. In each hour that it operates, the unit earns the difference between the market price and its operating costs. In each hour where the market prices are below the operating cost, the unit

is assumed to shut down. The dispatch uses the 2010 MRTU real-time market shape[5] (not the day-ahead market shape), and adjusts for temperature performance degradation using average monthly 9am – 10pm temperatures (see next section).

The market revenues earned in the energy and AS markets are subtracted from the fixed and variable costs of operating a CT to determine the residual capacity value. The capacity value calculations are performed using both Northern California and Southern California market prices and weather information. The cost of a new CT, however, is the same for both Northern and Southern California. Consistent with the DR methodology, the final capacity value for each year is the average of the results for Northern and Southern California (50% Northern and 50% Southern).

[5] The real-time market shape annual level is adjusted annually by 1) the percentage change in natural gas burner tip prices and 2) the energy market calibration factor. The energy market calibration factor is used to adjust the energy market prices to a level such that a new CCGT would not over or under collect in the resource balance and all subsequent years, and is described in more detail in the energy market section.

Figure 9: Statewide Generation Capacity Value before Temperature Adjustments



Hourly allocation of capacity value

The residual capacity value is allocated over the top 250 hours of CAISO system load, in inverse proportion to the gap between the system peak load plus operating reserves and the system loads for each of the 250 hours. In this manner, the highest load hour will receive the largest allocation of capacity value on a $/kWh basis (~$2,000/MWh). The 250th hour receives an allocation of ~$400/MWh. Most of the capacity value falls in the summer on-peak period, though some falls in the summer and winter partial-peak periods as well.

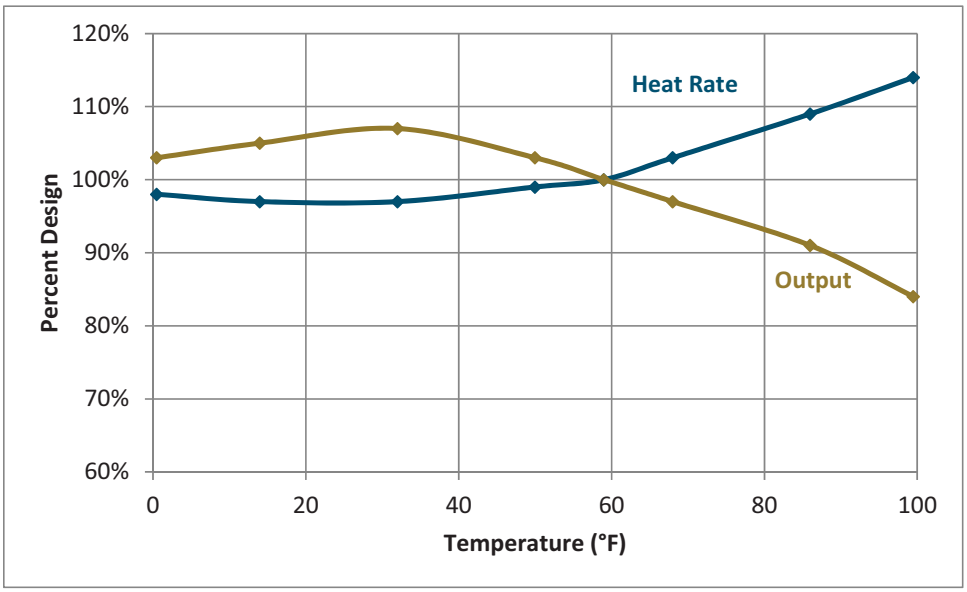
Temperature effect on unit performance

The capacity value as $ per kW of degraded capacity, rather than $ per kW of nameplate capacity to account for the effects of temperature. This re-expression increases the $/kW capacity value by about 8%. The use of the degraded capacity was introduced in the DR proceeding to more precisely model to operation of a combustion turbine at different ambient temperature conditions throughout the year. Use of degraded, rather than nameplate,

capacity value results an increase in the capacity value because combustion turbines perform at lower efficiencies when the ambient temperature is high.

The CT's rated heat rate and nameplate capacity characterize the unit's performance at ISO conditions,[6] but the unit's actual performance deviates substantially from these ratings throughout the year. In California, deviations from rated performance are due primarily to hourly variations in temperature. Figure 10 shows the relationship between temperature and performance for a GE LM6000 SPRINT gas turbine, a reasonable proxy for current CT technology.

Figure 10. Temperature-performance curve for a GE LM6000 SPRINT combustion turbine.



The effect of temperature on performance is incorporated into the calculation of the CT residual; several performance corrections are considered:

[6] ISO conditions assume 59ºF, 60% relative humidity, and elevation at sea level.

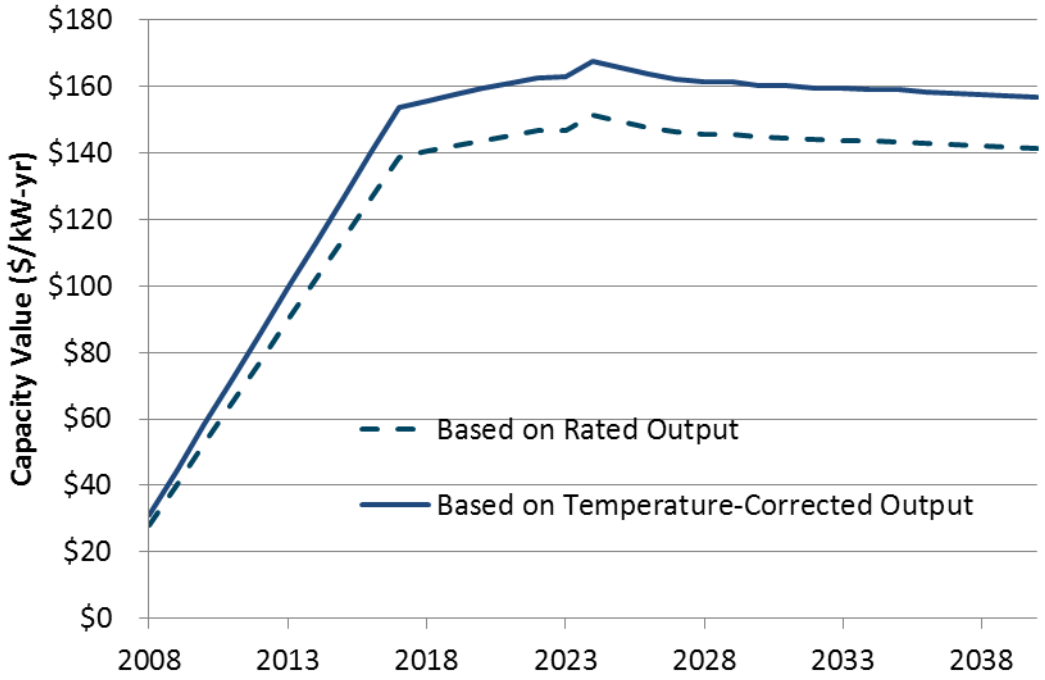
- In the calculation of the CT's dispatch, the heat rate is assumed to vary on a monthly basis. In each month, E3 calculates an average day-time temperature based on hourly temperature data throughout the state and uses this value to adjust the heat rate—and thereby the operating cost—within that month.

- Plant output is also assumed to vary on a monthly basis; the same average day-time temperature is used to determine the correct adjustment. This adjustment affects the revenue collected by the plant in the real-time market. For instance, if the plant's output is 90% of nameplate capacity in a given month, its net revenues will equal 90% of what it would have received had it been able to operate at nameplate capacity.

- The resulting capacity residual is originally calculated as the value per nameplate kilowatt—however, during the peak periods during which a CT is necessary for resource adequacy, high temperatures will result in a significant capacity deration. Consequently, the value of capacity is increased by approximately 10% to reflect the plant's reduced output during the top 250 load hours of the year as shown in Figure 11.

The forecast annual generation capacity values are shown below.

Figure 11. Adjustment of capacity value to account for temperature derating during periods of peak load



Planning reserve margin and losses

The capacity value is increased to account for both the Planning Reserve Margin (PRM) and losses. Resource Adequacy rules set capacity procurement targets for Load Serving Entities based on 1.15% of their forecasted load.[7] The must also account for losses in delivering electricity from the generator to the customer, based on peak loss factors for each utility. The capacity value is therefore increased by the PRM and the applicable loss factors for each utility. Note that peak loss factors are used for generation and T&D capacity while TOU loss factors are used for energy.

[7] See D.10-06-036 OP 6b, and the 2012 Final RA Guide at http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm

Ancillary Services (AS)

Besides reducing the cost of wholesale purchases, reductions in demand at the meter result in additional value from the associated reduction in required procurement of ancillary services. The CAISO MRTU markets include four types of ancillary services: regulation up and down, spinning reserves, and non-spinning reserves. The procurement of regulation services is generally independent of load; consequently, behind-the-meter load reductions and distributed generation exports will not affect their procurement. However, both spinning and non-spinning reserves are directly linked to load—in accordance with WECC reliability standards, the California ISO must maintain an operating reserve equal to 5% of load served by hydro generators and 7% of load served by thermal generators.

As a result, load reductions do result in a reduction in the procurement of reserves; the value of this reduced procurement is included as a value stream in the Avoided Cost Calculator. It is assumed that the value of avoided reserves procurement scales with the value of energy in each hour throughout the year. According to the CAISO's April 2011 Annual Report on Market Issues and Performance[8], CT A/S revenues from 2008 through 2010 averaged 7.6% of the CT energy market revenue. E3 uses this figure to assess the value of avoided A/S procurement in each hour.

T&D Capacity

The avoided electricity avoided costs include the value of reducing the need for transmission and distribution capacity expansion. Of the six avoided cost components, T&D costs are unique in that both the value and hourly allocation are location specific. Avoided T&D costs are

[8] Table 2.10 Financial analysis of a new combustion turbine (2006-2010)

determined separately for each utility. The avoided T&D costs have been updated by climate zone for PG&E, and at the system level for SCE and SDG&E territories based on utility ratemaking proceedings.[9] They are the same values used for the 2011 CEC California Building Energy Standards, and the CPUC CSI and DR proceedings. The PG&E values are close to the values used in those proceedings, but reflect a minor update that PG&E filed in its 2011 GRC Phase II proceeding on January 7, 2011. The T&D avoided costs escalate by 2% per year in nominal terms.

Table 3: Updated T&D Capacity Costs in 2011 ($/kW-yr)

	Sub transmission	Distribution	Total T&D, Adjusted For Losses
SCE	$23.39	$30.10	$55.42
SDG&E	$21.08	$52.24	$77.05
PG&E			
1			$83.02
2			$89.19
3A			$62.76
3B			$64.16
4			$74.94
5			$116.75
11			$93.79
12			$85.91
13			$77.51
16			$71.10

The value of deferring distribution investments is highly dependent the type and size of the equipment deferred and the rate of load growth, both of which vary significantly by location. Furthermore, some distribution costs are driven by distance or number of customers rather

[9] SDG&E did not have transmission avoided capacity costs at the time the CEC California Building Standard updates were prepared. The decision was made in consultation with SDG&E staff to use an average of SCE and PG&E transmission avoided costs as a proxy for SDG&E. That proxy value is maintained for the 2011 EE update.

than load and are therefore not avoided with reduced energy consumption. However, expediency and data limitations preclude analysis at a feeder by feeder level for a statewide analysis of avoided costs. The costs taken from utility rate case filings are used as a reasonable proxy for the long-run marginal cost T&D investment that is avoided over time with the addition of distributed energy resources. CPUC Feed-in-Tariff proceedings have considered identifying specific locations or "hotspots" where distributed generation will provide higher avoided T&D cost savings.[10] This approach is not currently incorporated in the avoided cost methodology.

The value of deferring transmission and distribution investments is adjusted for losses during the peak period using the factors shown in Table 4 and Table 5. These factors are lower than the energy and generation capacity loss factors because they represent losses from secondary meter to only the distribution or transmission facilities.

Table 4. Losses factors for SCE and SDG&E transmission and distribution capacity.

	SCE	SDG&E
Distribution	1.022	1.043
Transmission	1.054	1.071

[10] See E3 Avoided Cost Presentation at September 26, 2011 CPUC SB32 Workshop: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/sb2_1x.htm

Table 5: Losses factors for PG&E transmission and distribution capacity.

	Transmission	Distribution
CENTRAL COAST	1.053	1.019
DE ANZA	1.050	1.019
DIABLO	1.045	1.020
EAST BAY	1.042	1.020
FRESNO	1.076	1.020
KERN	1.065	1.023
LOS PADRES	1.060	1.019
MISSION	1.047	1.019
NORTH BAY	1.053	1.019
NORTH COAST	1.060	1.019
NORTH VALLEY	1.073	1.021
PENINSULA	1.050	1.019
SACRAMENTO	1.052	1.019
SAN FRANCISCO	1.045	1.020
SAN JOSE	1.052	1.018
SIERRA	1.054	1.020
STOCKTON	1.066	1.019
YOSEMITE	1.067	1.019

Hourly allocation of T&D capacity cost

The method for allocating T&D capacity costs to hours is unchanged from the extant method[11]. The method allocates the T&D capacity value in each climate zone to the hours of the year during which the system is most likely to be constrained and require upgrades—the hours of highest local load. Because local loads are not readily available for this analysis, hourly temperatures are used as a proxy to develop allocation factors for T&D value. This approach

[11] The DR proceeding changed the allocation of the T&D costs to hours using recent historical weather data. The weather data used for the EE avoided costs, however, must match the weather data used to model impacts in the DEER database. The 2011 update continues to use TMY weather data, as has been the practice since 2006.

results in an allocation of T&D value to several hundred of the hottest (and likely highest local load) hours of the year as presented in Figure 12 shows the total allocation of T&D within each month for each of the climate zones. Different weather patterns throughout the state result in unique allocators for T&D capacity. Generally, in hotter climate zones with loads driven by air conditioning, capacity value will be concentrated in more pronounced peaks than it is for the cooler climate zones.

Figure 12. Development of T&D allocators for CZ13

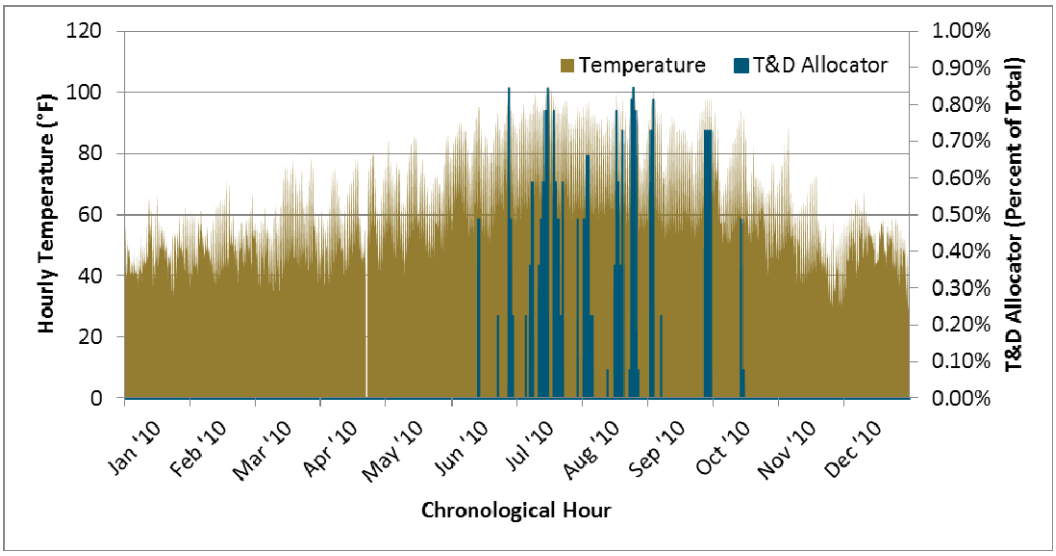
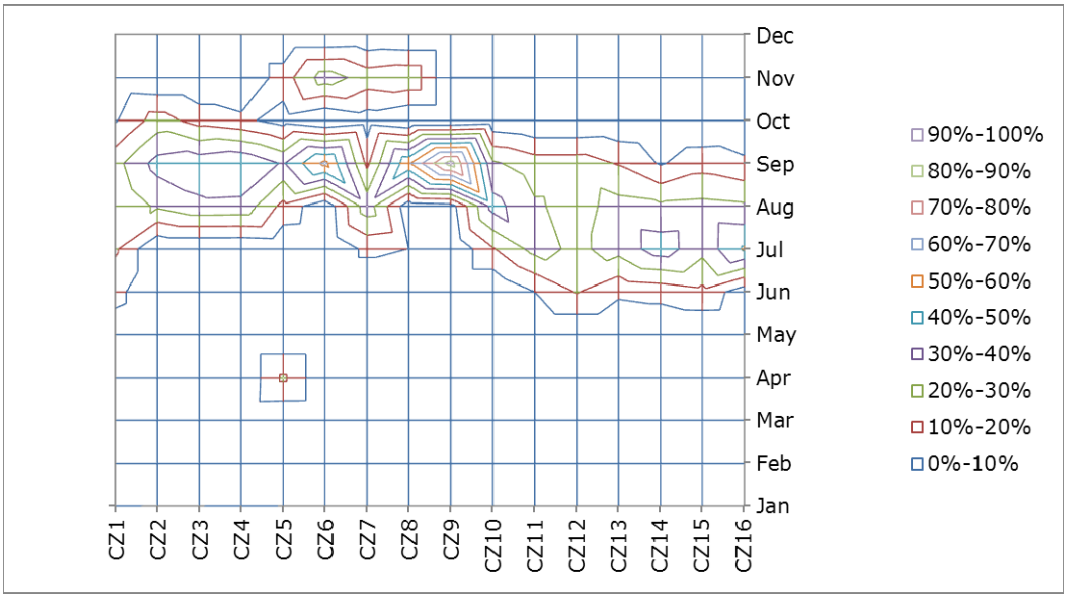


Figure 13. Monthly allocation of T&D capacity value across the sixteen climate zones.



T&D adjustment factors

Currently DR is unique in being considered as a dispatchable resource comparable to a CT. This has led to the use of several adjustment factors to account for the different availability, notification time, triggers and location of DR. A "D" factor for T&D value may be used by utilities to account for the potential for DR to avoid distribution upgrades. This is expected to be more common in the future as communication technology and AMI allow for DR dispatch based on local as well as system conditions. For other programs, which are not dispatchable by the utility, providing efficiency or generation throughout the year and broadly distributed throughout the service territory, utility average T&D avoided costs without adjustment are used.

Environment

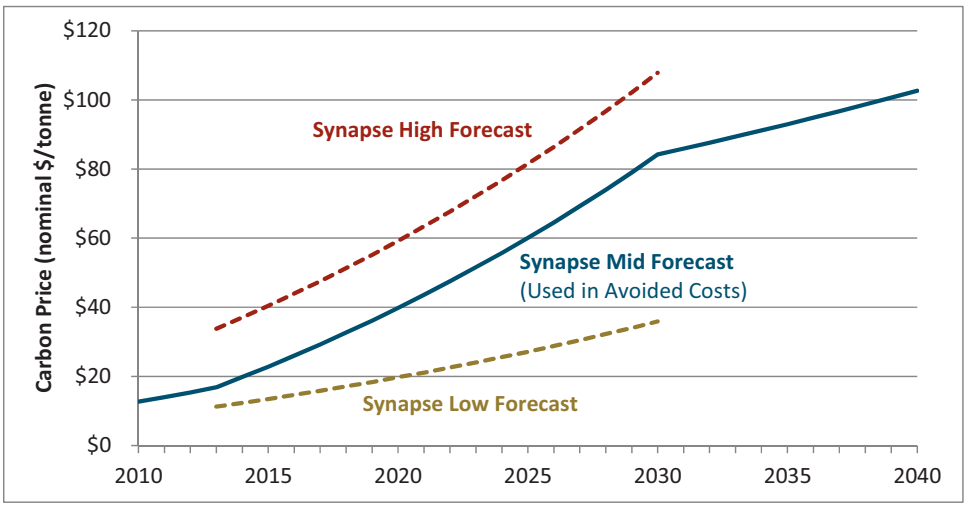
The environmental component is an estimate of the value of the avoided CO2 emissions. While there is not yet a CO2 market established in the US, it is included in the forecast of the future. While there is some probability that there will not be any cost of CO2, that the likelihood of

federal legislation establishing a cost of CO2 is high Since a forecast should be based on expected value, the avoided costs forecast includes the value of CO2.

More challenging for CO2 is estimating what the market price is likely to be, given a market for CO2 allowances is established. The price of CO2 will be affected by many factors including market rules, the stringency of the cap set on CO2 allowances, and other elements.

The extant E3 Calculators use $30 per short ton as the value of CO2 reductions from EE. This update uses a forecast developed by Synapse Consulting in 2008 (since updated in 2011) through a meta-analysis of various studies of proposed climate legislation. The Synapse mid-level forecast used for the update was developed explicitly for use in electricity sector integrated resource planning and so serves as an appropriate applied value for the cost of carbon dioxide emissions in the future. This is the same forecast used for CSI and DR. Figure 14 shows the Synapse price forecasts.

Figure 14. The CO2 price series embedded in the avoided cost values



The 2011 MPR adopted a new methodology for calculating assumed prices for California carbon emission allowances based on market price data for electricity and natural gas prices. Increases in the spark spread (the difference between electricity and natural gas prices) before and after major milestones in the development and adoption of CARB regulations are used to impute

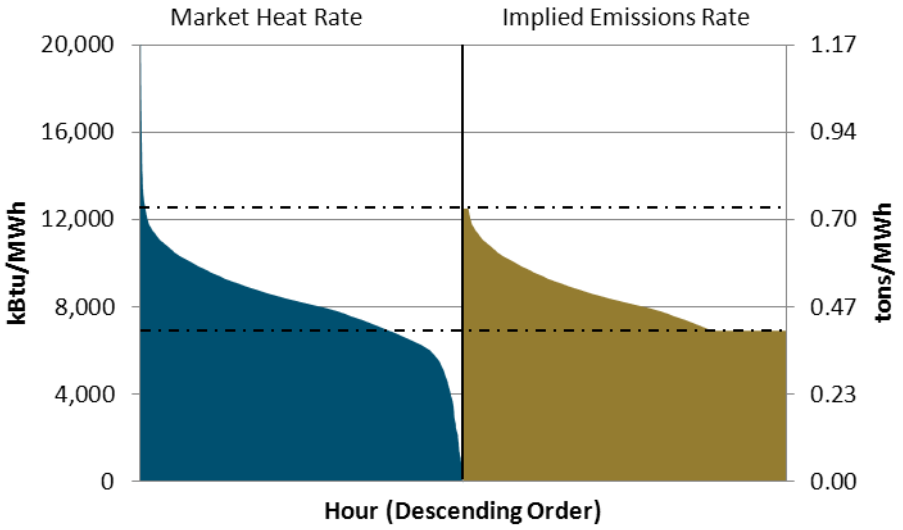
assumed CO2 prices. This method was developed in October 2011 for the 2011 MPR adopted in December 2011 and is not currently used in the avoided cost methodology. As CARB further defines and implements GHG regulations, it is reasonable to expect that the cost of carbon will be reflected in the forward market prices for electricity used to estimate the avoided generation costs. Future updates will consider how to best account for carbon costs embedded in the market price for electricity and avoid double counting.

The marginal rate of carbon emissions is calculated by the same method used for the extant EE avoided costs. Assuming that natural gas is the marginal fuel in all hours, the hourly emissions rate of the marginal generator is calculated based on the day-ahead market price curve. The link between higher market prices and higher emissions rates is intuitive: higher market prices enable lower-efficiency generators to operate, resulting in increased rates of emissions at the margin. Of course, this relationship holds for a reasonable range of prices but breaks down when prices are extremely high or low. For this reason, the avoided cost methodology bounds the maximum and minimum emissions rates based on the range of heat rates of gas turbine technologies. The maximum and minimum emissions rates are bounded by a range of heat rates for proxy natural gas plants shown in Table 6; the hourly emissions rates derived from this process are shown in Figure 15.

Table 6. Bounds on electric sector carbon emissions.

	Proxy Low Efficiency Plant	Proxy High Efficiency Plant
Heat Rate (Btu/kWh)	12,500	6,900
Emissions Rate (tons/MWh)	0.731	0.404

Figure 15. Hourly emissions rates derived from market prices (hourly values shown in descending order).



The 2004-2012 EE avoided cost methodology included explicit environmental adders for NOX and PM-10. E3 now believes that the costs for control and/or abatement of those emissions are captured in the capital cost of the new plants used to set the long-run cost of energy and capacity. Therefore, these quantities are no longer valued as a separate cost adder. As those costs were small in the 2004-2012 EE avoided cost methodology, their removal as an explicit adder has minimal impact.

Avoided Renewable Purchases Adder

This RPS adder reflects the fact that as energy usage declines, the amount of utility renewable purchases required to meet the RPS goals also declines. Since the cost of renewable energy is higher than the forecasted cost of wholesale energy and capacity market purchases, energy

reductions provide some value above the wholesale energy and capacity markets[12]. This adder is not included in the 2004-2012 EE avoided cost methodology.

In the DR methodology this adder is 33% (the RPS goal in 2020) of the cost difference forecast between RPS-eligible resources and the wholesale market price, beginning in 2020. This updated methodology incorporates the new SB2X, and has been updated to reflect the interim goals of 20% in 2013 and 25% in 2016.

The RPS Adder is a function of the Renewable Premium, the incremental cost of the marginal renewable resource above the cost of conventional generation. The marginal renewable resource is based upon the Fairmont CREZ, the most expensive resource bundle that is included in the renewable portfolio in E3's 33% Model 33% Reference Case. The Renewable Premium is calculated by subtracting the market energy and capacity value associated with this bundle, as well as the average CO2 emissions from a CCGT, from its levelized cost of energy as shown in Figure 16. The RPS Adder is calculated directly from the Renewable Premium by multiplying by the RPS goal for that year. For example, in 2021 the RPS adder is equal to the Renewable premium * 33%, as, for each 1 kWh of avoided retail sales, 0.33 kWh of renewable purchases are avoided. The RPS adder increases in a step-wise manner according to the goals set in 2013, 2016 and 2020. The actual procurement is likely to occur in a more linear fashion, but we expect that the impact of using one method over the other is quite small.

[12] For the CSI analysis, the only RPS goal was 33% in 2020, so the incremental RPS value only accrued in 2020 and beyond. With the passing of SB2X, this should be revised to reflect the 20% and 25% goals.

Figure 16. Evaluation of the Renewable Premium

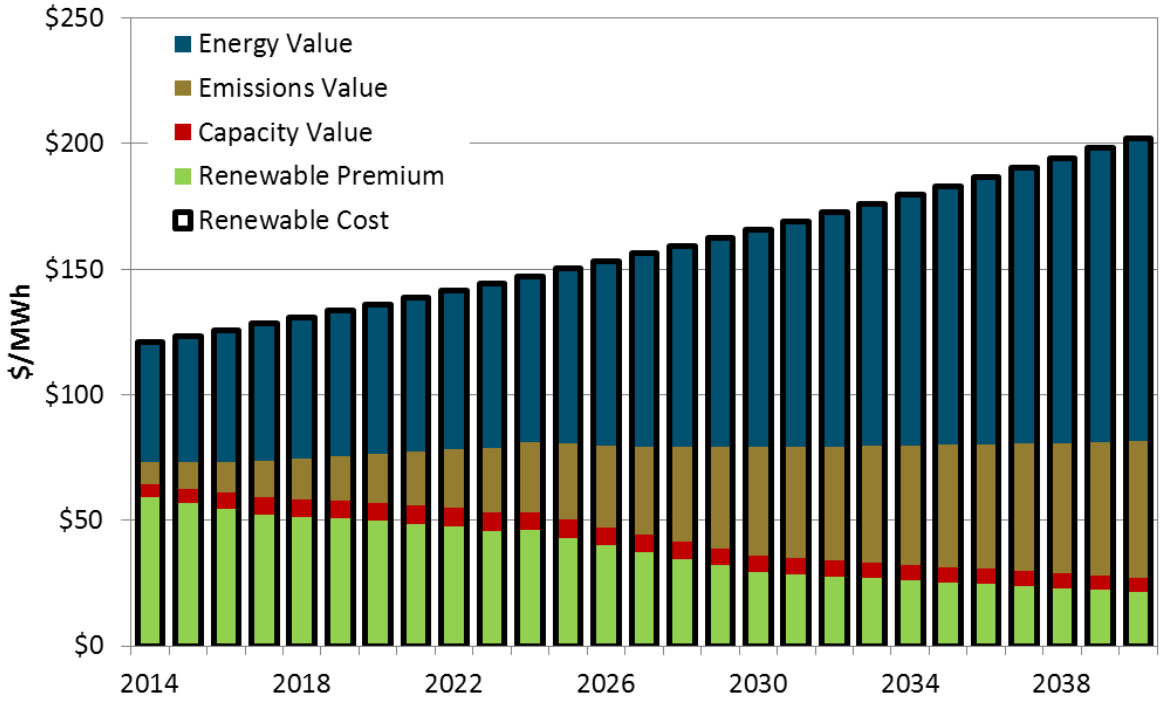
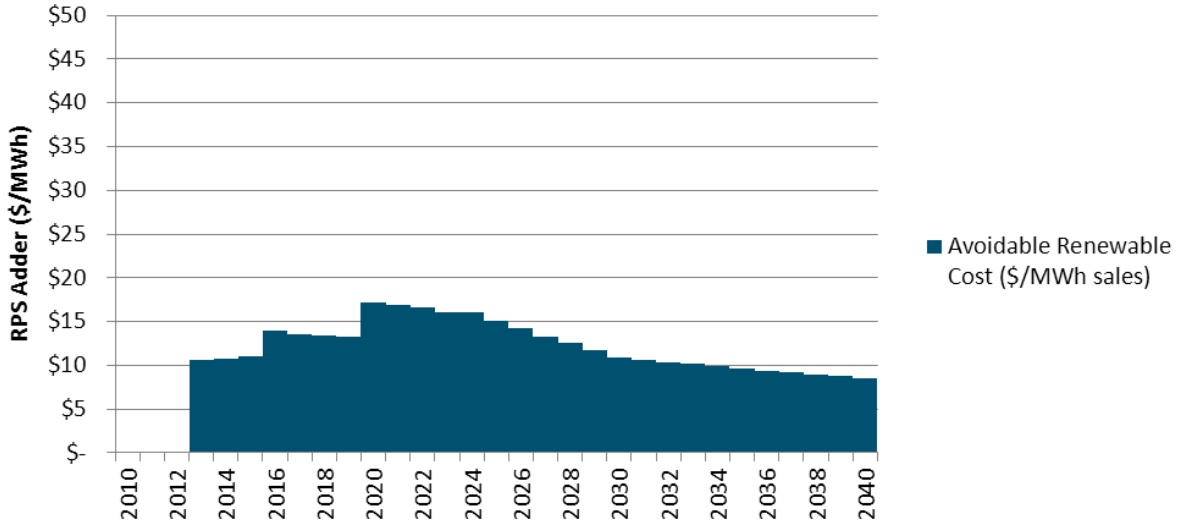


Figure 17: Annual RPS Adder



Components Not Included

Several components suggested by stakeholders in various proceedings are not currently included in the calculation of avoided costs. Non-energy Benefits (NEBs), by their nature, are difficult – if not impossible – to quantify. Work has been done to quantify some of these benefits for low income energy efficiency programs.[13] NEBs are not, however, currently included in the avoided cost methodology. The CPUC has authorized studies and pilot programs regarding embedded energy in water. To date a comprehensive framework for calculating embedded energy in water savings or water avoided costs in energy on a statewide basis has not yet been developed.[14] Avoided costs of current or future Ancillary Services associated with renewable integration or overgeneration are also not included. The need for flexible resources to provide services such as load following or ramping capability are driven primarily by the variation in, rather than the absolute level of, loads and generation. Finally the impacts of power factor and reactive loads are not currently included in the avoided cost methodology. An EM&V study for the CPUC Operational Energy Efficiency Program for water pumping produced by E3 found that the value of reduced reactive loads (kVAR) and associated line loss reductions ranged from 5 to 12 percent of the $/kWh avoided cost savings.[15] However the savings associated with improved power factor and reduced reactive load depend to a large extent on

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[13] More information about the use of non-energy benefits to evaluate Low Income programs can be found in the revised final report " *Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low Income Program Analyses in California*" issued May 11, 2010. http://www.liob.org/docs/LIEE%20Non-Energy%20Benefits%20Revised%20Report.pdf

[14] http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/Embedded+Energy+in+Water+Studies1_and_2.htm

[15] http://www.ethree.com/public_projects/cpucOEEP.php

the type and location of loads on the feeder. As with embedded energy in water, a generalized framework for a statewide analysis has not yet been performed.

Comparison of Generation-Related Avoided Cost Values

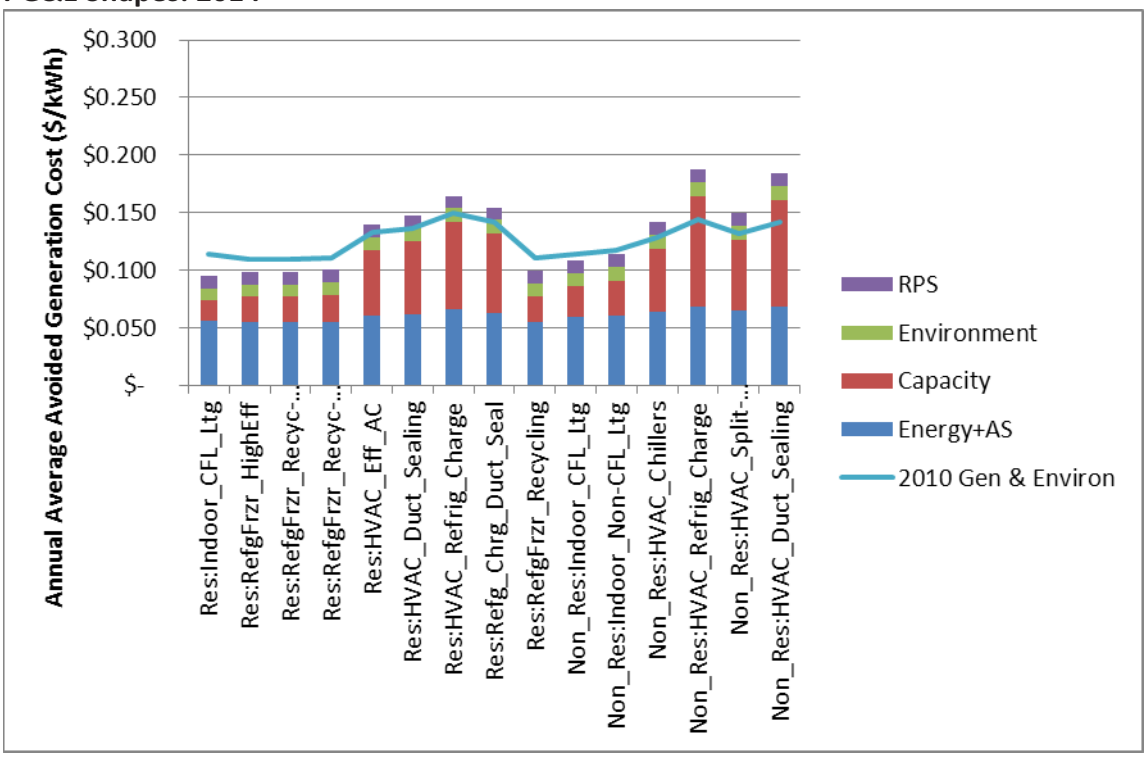
This section evaluates how the changes to generation-related avoided costs affect the avoided cost savings attributed to EE measures. We limit the comparison to the generation-related avoided costs (T&D excluded), because they comprise the largest changes.

The following charts compare the annual avoided costs for the DEER hourly load shapes used in the E3 Calculators. The stacked columns are the updated avoided costs by component, and the solid blue line is the corresponding value using the extant 2010-2012 EE avoided costs. (the legend "2010 Gen & Environ" indicates that the data is from the 2010-2012 calculators, NOT that it is the 2010 values). Snapshots are presented for 2014, and 2020.

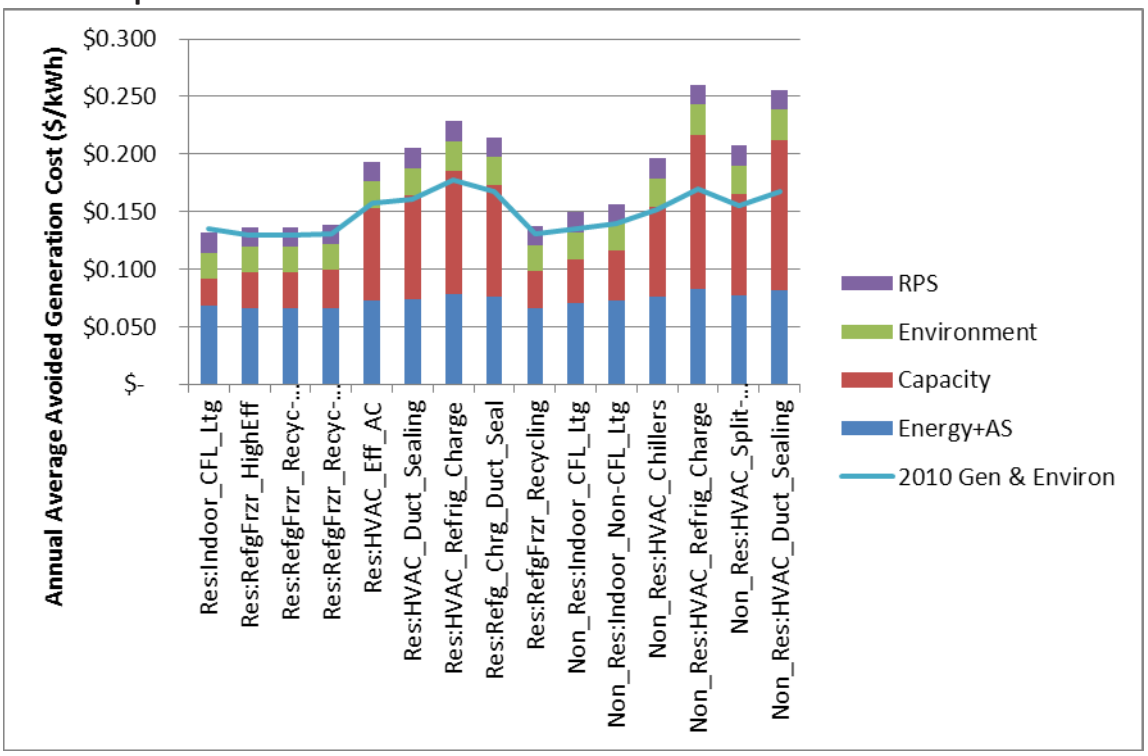
The figures for Northern California show that the updated avoided costs for lighting and refrigeration are lower in 2014, while HVAC is higher. In 2020, the updated avoided costs have lighting at roughly the same level as the 2010-2012 avoided costs, while HVAC is substantially higher.

For Southern California, the updated avoided costs lower the results for non-HVAC load shapes in 2014. In 2020, the updated avoided costs have lighting at roughly the 2010-2012 avoided cost level, and HVAC measures are higher.

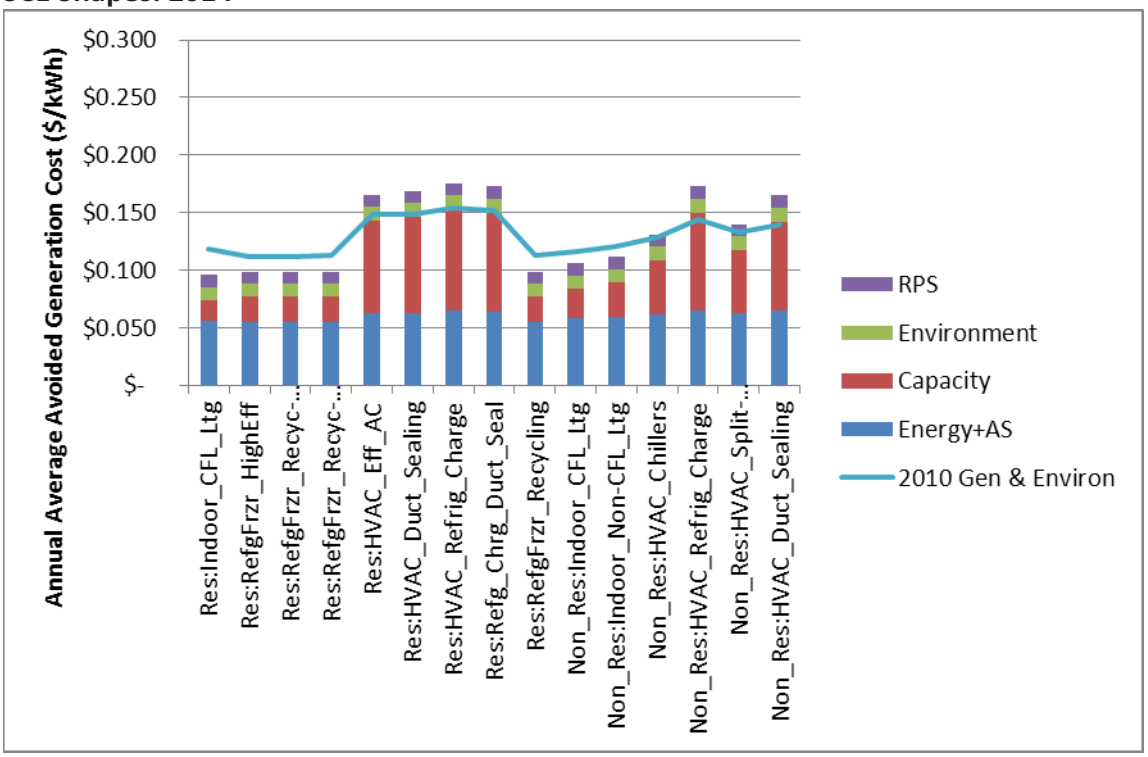
PG&E Shapes: 2014



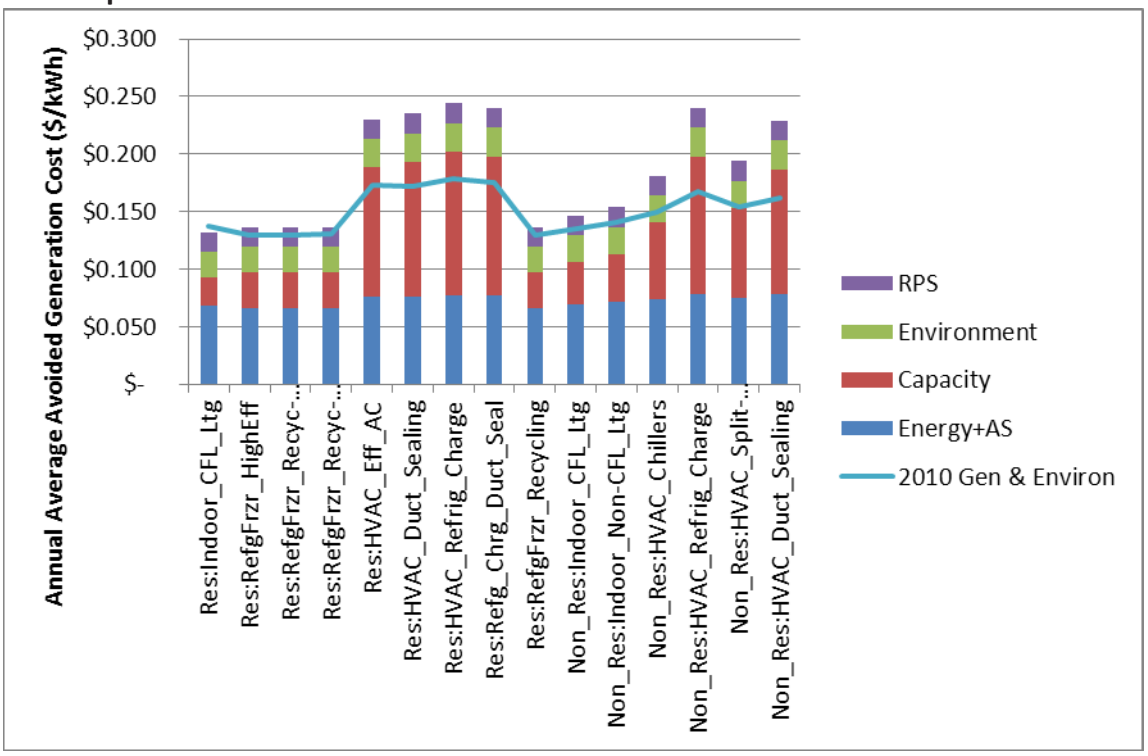
PG&E Shapes: 2020



SCE Shapes: 2014



SCE Shapes: 2020

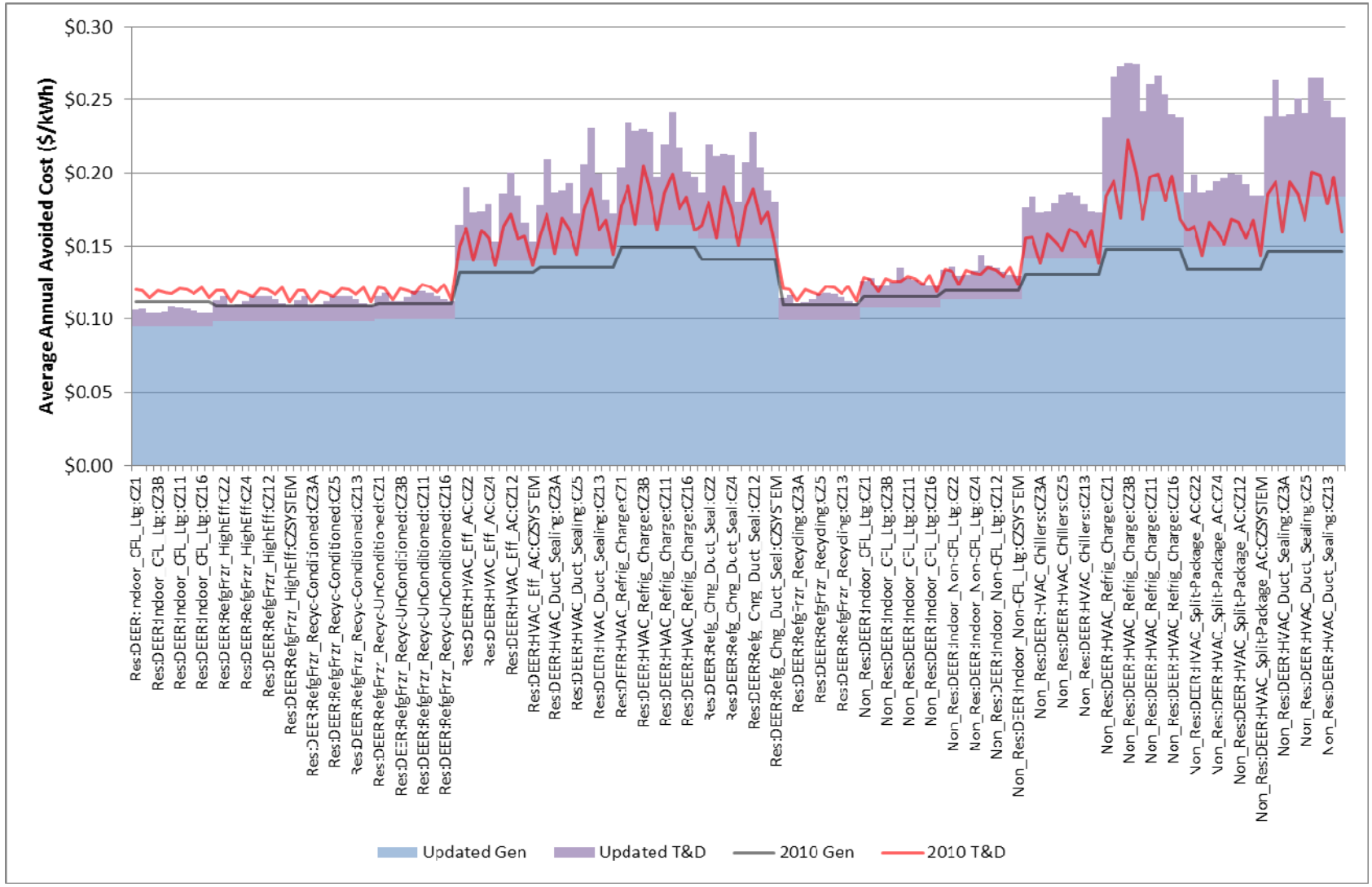


Comparison of the Updated EE Avoided Costs to 2010-2012 EE Avoided Costs

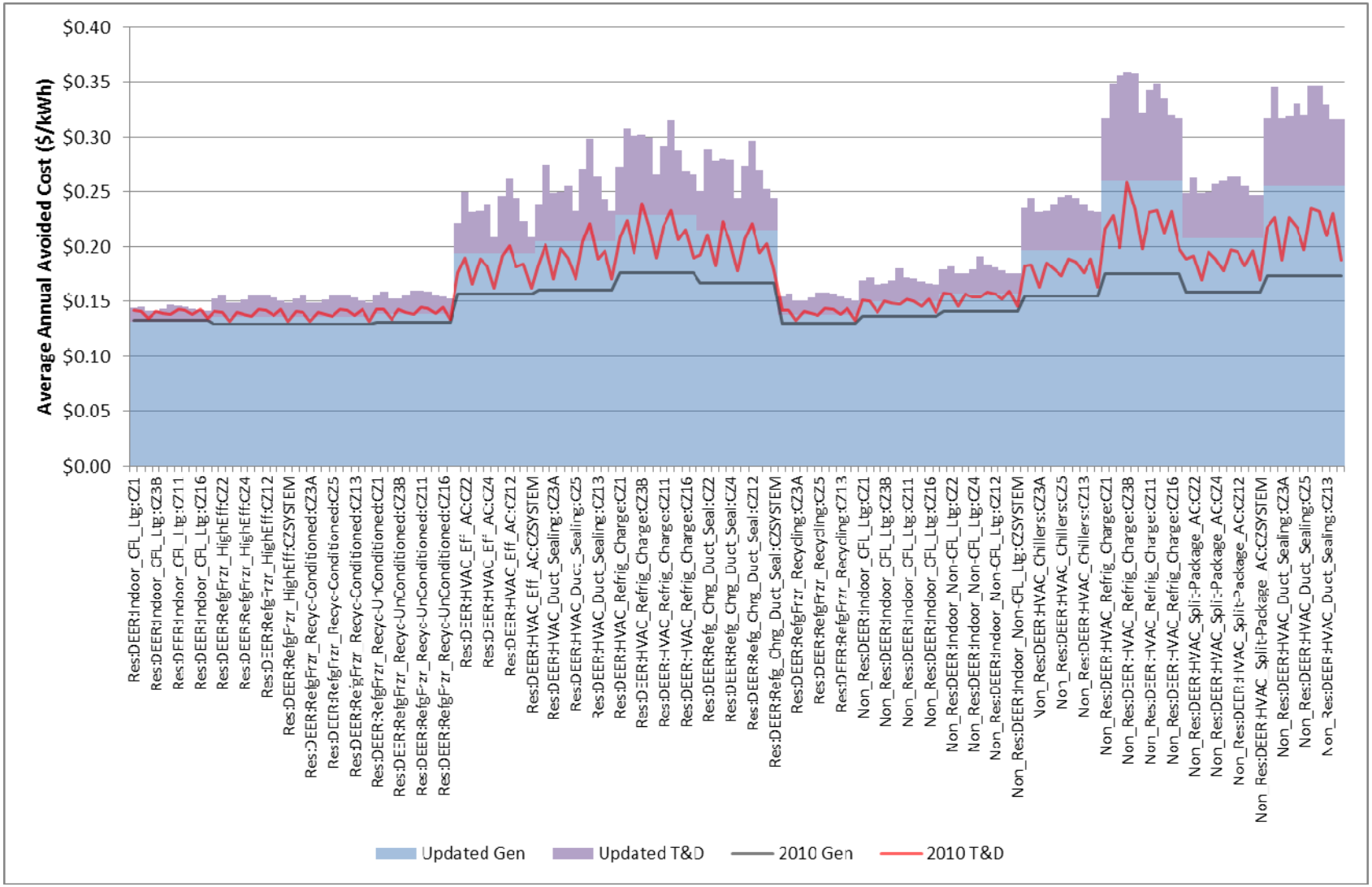
Shown in this section are the total annual average avoided costs for DEER measures by climate zone. The avoided costs for generation (Gen) and transmission and distribution (T&D) are plotted separately. The 2010-2012 EE annual average avoided costs for each DEER measure are shown as stacked lines. 2010 Gen includes energy, emissions, ancillary services, and losses. 2010 T&D is the T&D capacity and losses. The annual average avoided costs using 2014 updated EE are plotted as stacked column charts. 2014 Gen includes energy, capacity, emissions, ancillary services, RPS costs, and losses. 2014 T&D includes T&D capacity and losses.

For each utility a plot of the DEER measure shape avoided costs are shown for 2014, followed by 2020.

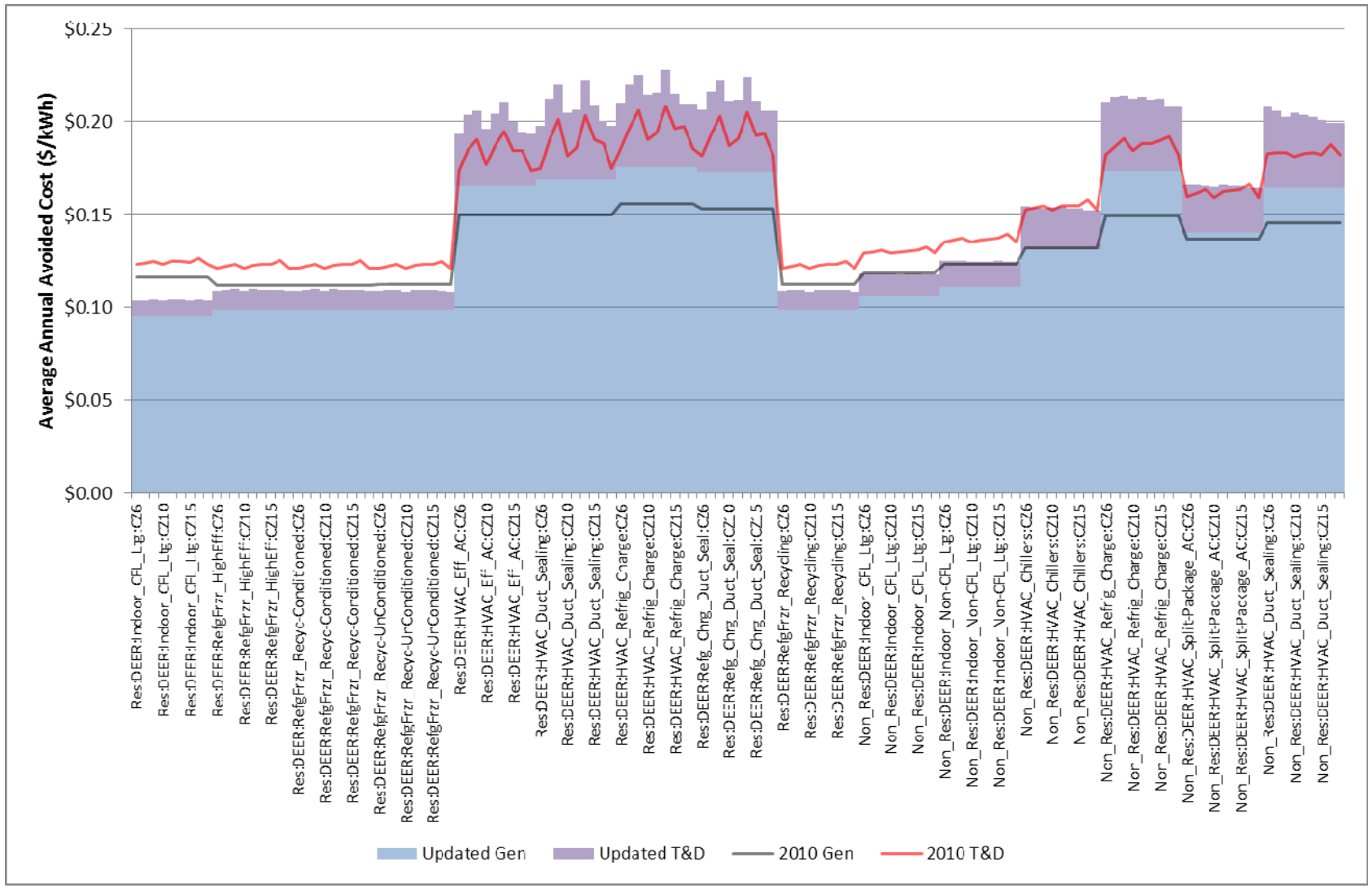
PG&E 2014


Average Annual Avoided Cost ($/kWh)
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Updated Gen
Updated T&D
2010 Gen
2010 T&D

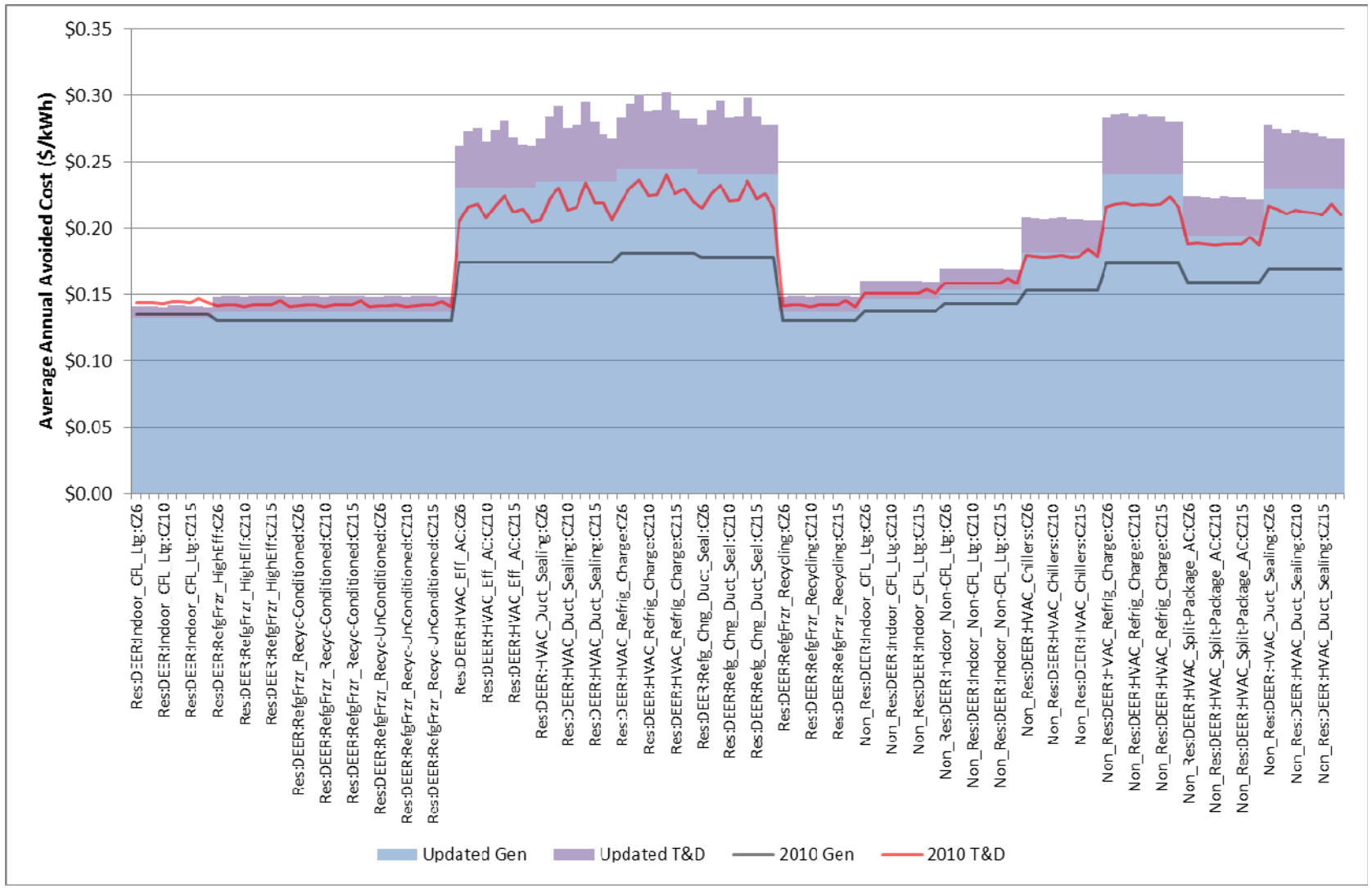
PG&E 2020


Average Annual Avoided Cost ($/kWh)
$0.40
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Updated Gen
Updated T&D
2010 Gen
2010 T&D

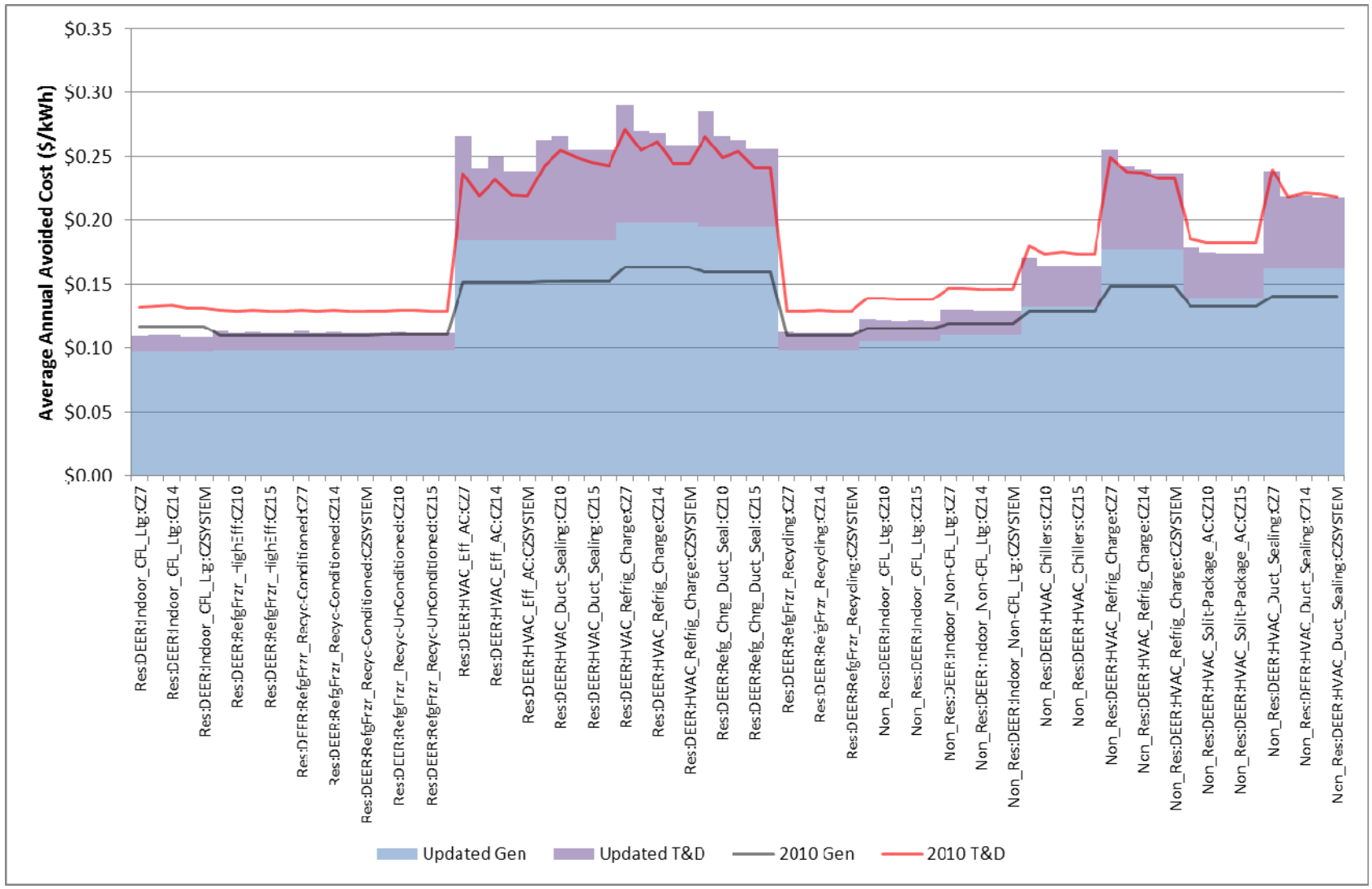
SCE 2014


Average Annual Avoided Cost ($/kWh)
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Updated Gen
Updated T&D
2010 Gen
2010 T&D

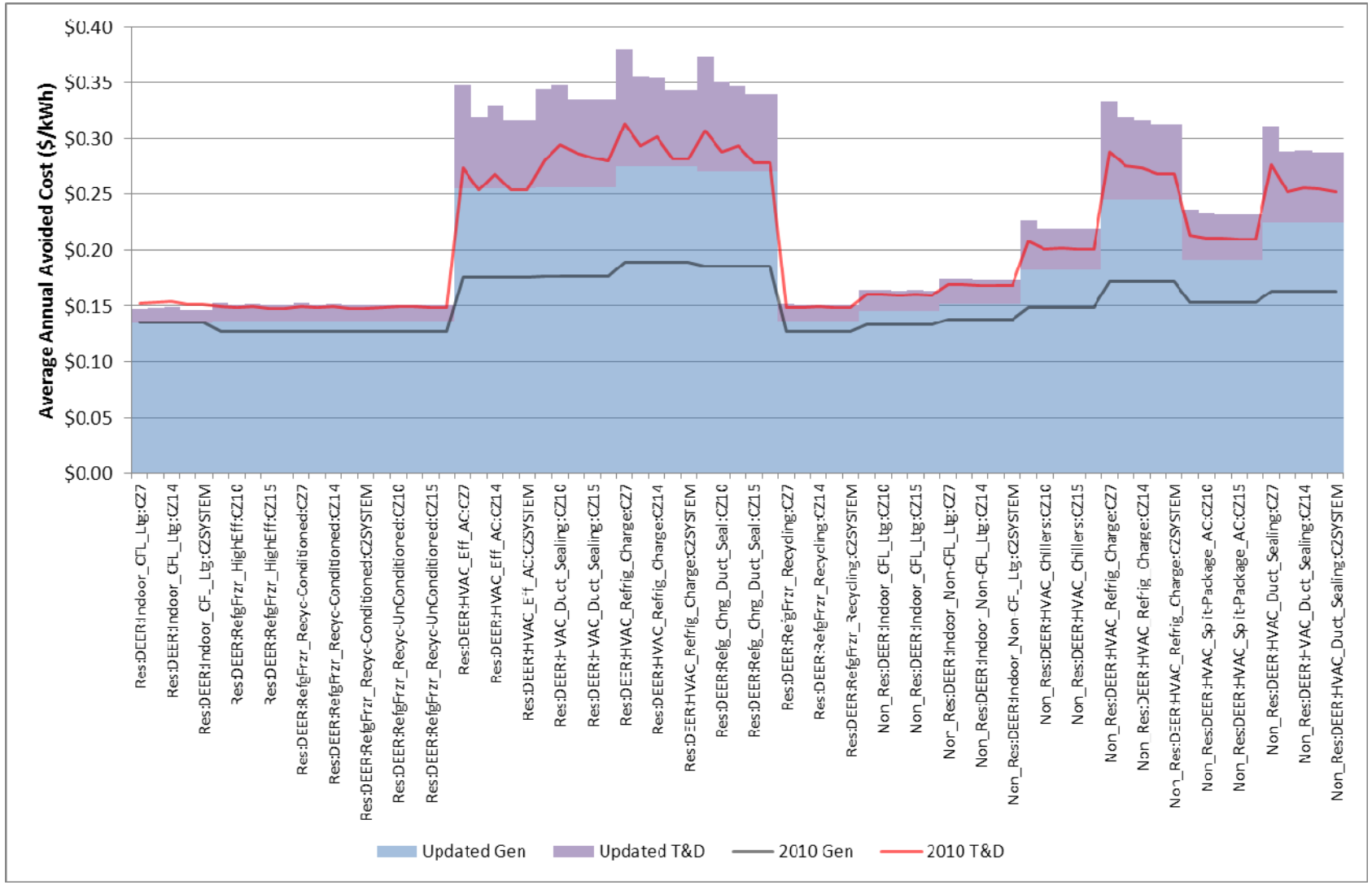
SCE 2020


Average Annual Avoided Cost ($/kWh)
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Updated Gen
Updated T&D
2010 Gen
2010 T&D

SDG&E 2014


Average Annual Avoided Cost ($/kWh)
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Res:DEER:Indoor_CFL_Ltg:CZ7
Res:DEER:Indoor_CFL_Ltg:CZ14
Res:DEER:Indoor_CFL_Ltg:CZSYSTEM
Res:DEER:RefgFrzr_Light:CZ10
Res:DEER:RefgFrzr_Light:CZ15
Res:DEER:RefgFrzr_Recyc-Conditioned:CZ7
Res:DEER:RefgFrzr_Recyc-Conditioned:CZ14
Res:DEER:RefgFrzr_Recyc-Conditioned:CZSYSTEM
Res:DEER:RefgFrzr_Recyc-UnConditioned:CZ10
Res:DEER:RefgFrzr_Recyc-UnConditioned:CZ15
Res:DEER:HVAC_Eff_AC:CZ7
Res:DEER:HVAC_Eff_AC:CZ14
Res:DEER:HVAC_Eff_AC:CZSYSTEM
Res:DEER:HVAC_Duct_Sealing:CZ10
Res:DEER:HVAC_Duct_Sealing:CZ15
Res:DEER:HVAC_Refrig_Charge:CZ7
Res:DEER:HVAC_Refrig_Charge:CZ14
Res:DEER:HVAC_Refrig_Charge:CZSYSTEM
Res:DEER:Refg_Chrg_Duct_Seal:CZ10
Res:DEER:Refg_Chrg_Duct_Seal:CZ15
Res:DEER:RefgFrzr_Recycling:CZ7
Res:DEER:RefgFrzr_Recycling:CZ14
Res:DEER:RefgFrzr_Recycling:CZSYSTEM
Non_Res:DEER:Indoor_CFL_Ltg:CZ10
Non_Res:DEER:Indoor_CFL_Ltg:CZ15
Non_Res:DEER:Indoor_Non-CFL_Ltg:CZ7
Non_Res:DEER:Indoor_Non-CFL_Ltg:CZ14
Non_Res:DEER:Indoor_Non-CFL_Ltg:CZSYSTEM
Non_Res:DEER:HVAC_Chillers:CZ10
Non_Res:DEER:HVAC_Chillers:CZ15
Non_Res:DEER:HVAC_Refrig_Charge:CZ7
Non_Res:DEER:HVAC_Refrig_Charge:CZ14
Non_Res:DEER:HVAC_Refrig_Charge:CZSYSTEM
Non_Res:DEER:HVAC_Split-Package_AC:CZ10
Non_Res:DEER:HVAC_Split-Package_AC:CZ15
Non_Res:DEER:HVAC_Duct_Sealing:CZ7
Non_Res:DEER:HVAC_Duct_Sealing:CZ14
Non_Res:DEER:HVAC_Duct_Sealing:CZSYSTEM
Updated Gen
Updated T&D
2010 Gen
2010 T&D

SDG&E 2020


Average Annual Avoided Cost ($/kWh)
$0.40
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Res:DEER:Indoor_CFL_Ltg:CZ7
Res:DEER:Indoor_CFL_Ltg:CZ14
Res:DEER:Indoor_CFL_Ltg:CZSYSTEM
Res:DEER:RefgFrzr_HighEff:CZ10
Res:DEER:RefgFrzr_HighEff:CZ15
Res:DEER:RefgFrzr_Recyc-Conditioned:CZ7
Res:DEER:RefgFrzr_Recyc-Conditioned:CZ14
Res:DEER:RefgFrzr_Recyc-Conditioned:CZSYSTEM
Res:DEER:RefgFrzr_Recyc-UnConditioned:CZ10
Res:DEER:RefgFrzr_Recyc-UnConditioned:CZ15
Res:DEER:HVAC_Eff_AC:CZ7
Res:DEER:HVAC_Eff_AC:CZ14
Res:DEER:HVAC_Eff_AC:CZSYSTEM
Res:DEER:HVAC_Duct_Sealing:CZ10
Res:DEER:HVAC_Duct_Sealing:CZ15
Res:DEER:HVAC_Refrig_Charge:CZ7
Res:DEER:HVAC_Refrig_Charge:CZ14
Res:DEER:HVAC_Refrig_Charge:CZSYSTEM
Res:DEER:Refg_Chrg_Duct_Seal:CZ10
Res:DEER:Refg_Chrg_Duct_Seal:CZ15
Res:DEER:RefgFrzr_Recycling:CZ7
Res:DEER:RefgFrzr_Recycling:CZ14
Res:DEER:RefgFrzr_Recycling:CZSYSTEM
Non_Res:DEER:Indoor_CFL_Ltg:CZ10
Non_Res:DEER:Indoor_CFL_Ltg:CZ15
Non_Res:DEER:Indoor_Non-CFL_Ltg:CZ7
Non_Res:DEER:Indoor_Non-CFL_Ltg:CZ14
Non_Res:DEER:Indoor_Non CFL_Ltg:CZSYSTEM
Non_Res:DEER:HVAC_Chillers:CZ10
Non_Res:DEER:HVAC_Chillers:CZ15
Non_Res:DEER:HVAC_Refrig_Charge:CZ7
Non_Res:DEER:HVAC_Refrig_Charge:CZ14
Non_Res:DEER:HVAC_Refrig_Charge:CZSYSTEM
Non_Res:DEER:HVAC_Split-Package_AC:CZ10
Non_Res:DEER:HVAC_Split-Package_AC:CZ15
Non_Res:DEER:HVAC_Duct_Sealing:CZ7
Non_Res:DEER:HVAC_Duct_Sealing:CZ14
Non_Res:DEER:HVAC_Duct_Sealing:CZSYSTEM
Updated Gen
Updated T&D
2010 Gen
2010 T&D

Key Data Sources and Specific Methodology

This section provides further discussion of data sources and methods used in the calculation of the hourly avoided costs.

Power plant cost assumptions

The cost and performance assumptions for the new simple cycle plants are based on the 100 MW simple cycle turbine included in the California Energy Commission's Cost of Generation report.

Table 7. Power plant cost and performance assumptions (all costs in 2009 $)

	Simple Cycle Gas Turbine
Heat Rate (Btu/kWh)	9,300
Plant Lifetime (yrs)	20
Instant Cost ($/kW)	$1,230
Fixed O&M ($/kW-yr)	$17.40
Variable O&M ($/kW-yr)	$4.17
Debt-Equity Ratio	60%
Debt Cost	7.70%
Equity Cost	11.96%

Hourly Allocation of Generation Capacity Value

The generation capacity value is allocated to hours using the methodology from the DR proceeding. Capacity value is allocated to 250 hours based upon hourly system load data collected from 2007 through 2010. In each full calendar year, hourly allocators are calculated for that year's top 250 load hours; the allocators, which sum to 100% within each year, are inversely proportional to the difference between the annual peak plus operating reserves and the loads in each hour. This allocation methodology, which serves as a simplified and transparent proxy for models of relative loss-of-load probability (rLOLP), results in allocators that increase with the load level.

The annual series of allocators for each of the full calendar years are used to develop reasonable estimates of the relative fraction of capacity value that is captured within each month as shown in Figure 18. By considering loads within the four-year period from 2007-2010, the Avoided Cost Calculator captures the potential diversity of peak loads across different years.

Figure 18. Calculation of monthly capacity allocation based on historical data from 2007-2010.

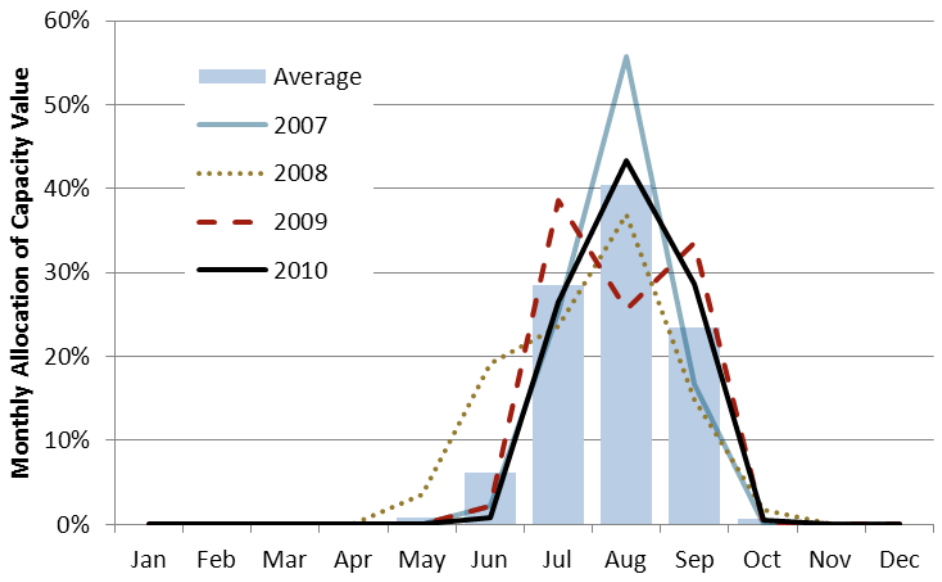


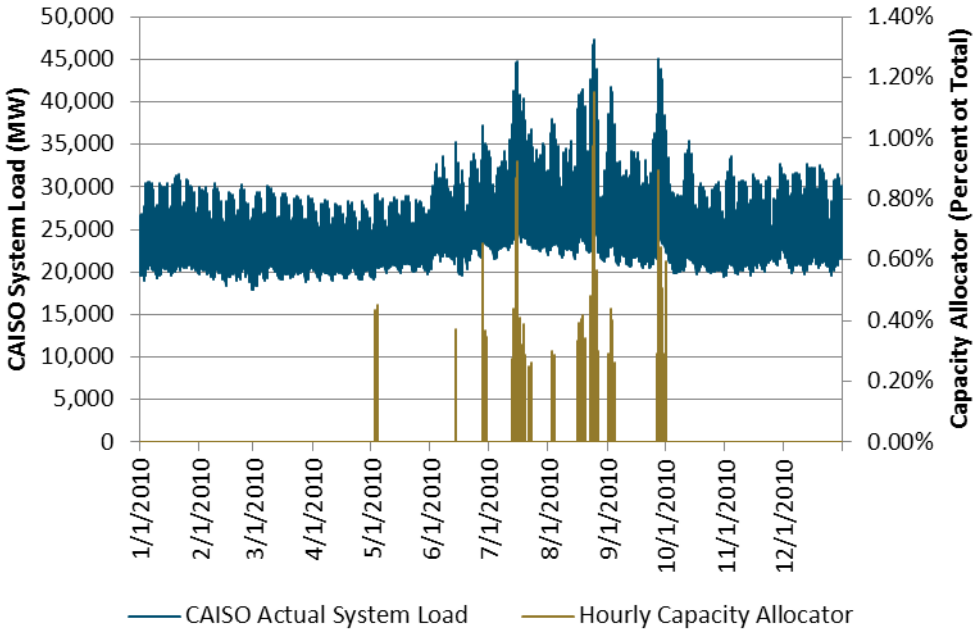
Table 8. Summary of monthly capacity allocation based on historical load data from 2007-2010.

Month	Capacity Allocation (%)	Rounded Number of Peak Hours
January	0.0%	-
February	0.0%	-
March	0.0%	-
April	0.0%	-
May	0.9%	2
June	6.1%	14
July	28.5%	75
August	40.4%	98

September	23.5%	60
October	0.6%	1
November	0.0%	-
December	0.0%	-
Total	100.0%	250

The hourly allocation uses the rounded number of peak hours from above to determine the number of peak hours that are deemed to occur in each month. The algorithm used to allocate the value of capacity to hours parallels the process used for the historical analysis but shifts the time scale from allocation across an entire year to allocation within single months. Thus, for each month in 2010, the value of capacity is allocated to the number of peak hours in that month so that the allocators sum to the total monthly allocation shown in Table 8. As with the historical analysis, the allocators are inversely proportional to the difference between the month's peak load plus operating reserves and the load in the relevant hour.

Figure 19. Hourly allocation of generation capacity based on loads for 2010.



Calculation of the T&D Capacity Allocators

The following is a brief description of the algorithm used to allocated T&D capacity value. T&D capacity value is allocated to all hours with temperatures within 15ºF of the peak annual temperature.

1. Select all hours with temperatures within 15ºF of the peak annual temperature (excluding hours on weekends and holidays) and order them in descending order
2. Assign each hour an initial weight using a triangular algorithm, such that the first hour (with the highest temperature) has a weight of 2/(n+1) and the weight assigned to each subsequent hour decreases by 2/[n*(n+1)], where n is the number of hours that have a temperature above the threshold established in the first step
3. Average the initial weights among all hours with identical temperatures so that hours with the same temperature receive the same weight

Generation Loss Factors

The updated avoided costs incorporate loss factors from the DR proceeding. The capacity loss factors are applied to the capacity avoided costs to reflect the fact that dispatched generation capacity is greater than metered loads because of losses. The adjustments assume that the metered load is at the secondary voltage level. The loss factors are representative of average peak losses, not incremental losses.

Table 9: Generation capacity loss factors

	PG&E	SCE	SDG&E
Generation to meter	1.109	1.084	1.081

The energy loss factors are applied to the electricity energy costs to reflect energy losses down to the customer secondary meter. The loss factors vary by utility time of user period, and represent average losses in each time period.

Energy Generated[h] = Metered Load[h] * Energy Loss Factor[TOU]

Cost of Energy Losses = Energy Cost[h] * Metered Load [h] * (Energy Loss Factor[TOU] – 1)

where h = hour, TOU = TOU period corresponding to hour h.

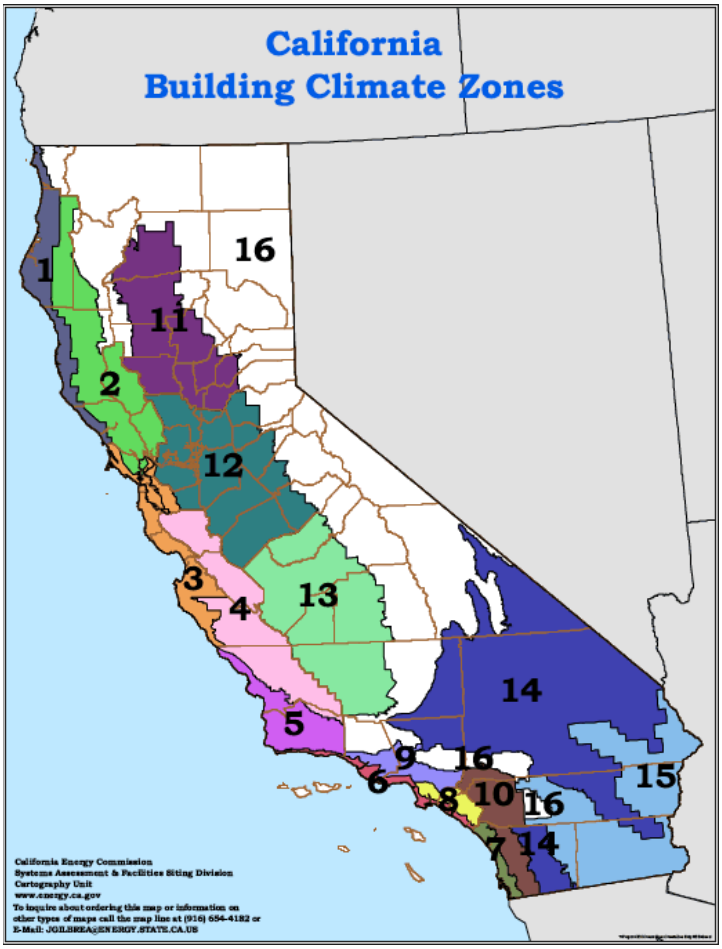
Table 10. Marginal energy loss factors by time-of-use period and utility.

Time Period	PG&E	SCE	SDG&E
Summer Peak	1.109	1.084	1.081
Summer Shoulder	1.073	1.080	1.077
Summer Off-Peak	1.057	1.073	1.068
Winter Peak	-	-	1.083
Winter Shoulder	1.090	1.077	1.076
Winter Off-Peak	1.061	1.070	1.068

Climate Zones

In each hour, the value of electricity delivered to the grid depends on the point of delivery. The DG Cost-effectiveness Framework adopts the sixteen California climate zones defined by the Title 24 building standards in order to differentiate between the value of electricity in different regions in the California. These climate zones group together areas with similar climates, temperature profiles, and energy use patterns in order to differentiate regions in a manner that captures the effects of weather on energy use. Figure 20 is a map of the climate zones in California.

Figure 20. California Climate Zones



Each climate zone has a single representative city, which is specified by the California Energy Commission. These cities are listed in Table 11. Hourly avoided costs are calculated for each climate zone.

Table 11. Representative cities and utilities for the California climate zones.

Climate Zone	Utility Territory	Representative City
CEC Zone 1	PG&E	Arcata
CEC Zone 2	PG&E	Santa Rosa
CEC Zone 3	PG&E	Oakland
CEC Zone 4	PG&E	Sunnyvale
CEC Zone 5	PG&E/SCE	Santa Maria
CEC Zone 6	SCE	Los Angeles
CEC Zone 7	SDG&E	San Diego
CEC Zone 8	SCE	El Toro
CEC Zone 9	SCE	Pasadena
CEC Zone 10	SCE/SDG&E	Riverside
CEC Zone 11	PG&E	Red Bluff
CEC Zone 12	PG&E	Sacramento
CEC Zone 13	PG&E	Fresno
CEC Zone 14	SCE/SDG&E	China Lake
CEC Zone 15	SCE/SDG&E	El Centro
CEC Zone 16	PG&E/SCE	Mount Shasta

(End of Attachment A)

ATTACHMENT B

USE OF BEFORE- AND AFTER-TAX DISCOUNT RATES IN EE COST EFFECTIVENESS EVALUATIONS

ATTACHMENT B

USE OF BEFORE- AND AFTER-TAX DISCOUNT RATES IN EE COST EFFECTIVENESS EVALUATIONS

Prepared by Energy and Environmental Economics (E3), for the CPUC

Summary

At issue herein is the question of whether a before-tax or after-tax utility discount rate should be adopted for use in energy efficiency (EE) cost-effectiveness evaluations. Both types of utility discount rates have been used in past CPUC proceedings for the valuation of energy efficiency, as well as in other utility proceedings. Part of the confusion is that both discount rates can be correct, depending on how cash flows are represented.

In the examples below, we proceed under the paradigm that EE costs and benefits are evaluated consistent with any utility investment. Therefore it is useful to start with a simple utility project valuation example to illustrate the correct application of both the before-tax and after-tax weighted average cost of capital values.

Examples

Consider the following example, with both debt and equity components of the capital structure equal to 50%, an equity cost of 12%, and a debt cost of 6%. The calculation of the before-tax WACC is the weighted average of the debt and equity cost of capital, as shown in Table 1. Assuming an investment of $1000, and a five year straight line depreciation of that investment, we have the cash flows shown in Table 2. Table 2 does not explicitly recognize that debt costs are considered a tax-deductible expense. Accordingly, the appropriate discount rate to use with these cash flows is the before-tax WACC of 9.0%. This is confirmed by Column H in Table 2 that shows that the net present value correctly sums to zero when the before-tax WACC is used to discount the cash flows.

Table 1: Before-tax WACC

	Share	Rate	Weighted Rate
Equity	50%	12%	6.00%
Debt	50%	6%	3.00%
Before-tax WACC			**9.00%**

Table 2: Cash flows ignoring the tax deductibility of debt costs

A	*B*	*C*	*D*	*E*	*F*	*G*		*H*
Year	Investment	Net Book (Prior Yr C - Prior Yr G)	Equity Cost (C * 12%*50%)	Debt Cost (C * 6%*50%)	Depreciation (B/5)	Total Cost (B+D+E+F)		Discounted at WACC (G/(1+9.0%)^A)
0	-1000					-1000	$	(1,000.00)
1		1000	60	30	200	290	$	266.06
2		800	48	24	200	272	$	228.94
3		600	36	18	200	254	$	196.13
4		400	24	12	200	236	$	167.19
5		200	12	6	200	218	$	141.69
6		0	0	0				
NPV using before-tax WACC (sum of years 0 to 5)							**$**	**-**

Now consider the same example, but explicitly recognize that debt costs are tax-deductible at a marginal tax rate of 40%. Table 3 shows the after-tax WACC of 7.8%, which is 1.2% (= 40% tax rate * 6% interest rate * 50% debt in the capital structure) less than the before-tax WACC.

Table 3: After-tax WACC

	Share	Rate	Tax effect	Weighted Rate
Equity	50%	12%		6.00%
Debt	50%	6%	-1.2%	1.80%
After-Tax WACC				**7.80%**

Table 4 shows cash flows for the same investment used for Table 2. The difference is that Column G now explicitly recognizes the tax deductibility of debt costs. Therefore, the Total Cost cash flows in Table 4 column H are lower than those shown in Column G of Table 2 by the amount of the debt tax shield. Column I shows that when using cash flows that recognize the tax deductibility of debt costs, the lower after-tax WACC of 7.8% is the correct discount rate, yielding an NPV of zero.

Table 4: Cash flows recognizing the tax deductibility of debt costs

A	*B*	*C*	*D*	*E*	*F*	*G*	*H*	*I*
Year	Invest -ment	Net Book (Prior Yr C - Prior Yr G)	Equity Cost (C * 12%*50%)	Debt Cost (C * 6%*50 %)	Deprec- iation (B/5)	Tax Effect of debt (E*-40%)	Total Cost (B+D+E+F+G)	Discounted at after-tax WACC (H/(1+7.8%)^A)
0	-1000						-1000	$ (1,000.00)
1		1000	60	30	200	-12	278	$ 257.88
2		800	48	24	200	-9.6	262.4	$ 225.80
3		600	36	18	200	-7.2	246.8	$ 197.01
4		400	24	12	200	-4.8	231.2	$ 171.20
5		200	12	6	200	-2.4	215.6	$ 148.10
6		0	0	0		0		
NPV using after-tax WACC (sum of years 0 to 5)								**$ -**

The above examples demonstrate that the choice of discount rates is dependent on how taxes are treated in the future cash flows. The treatment of taxes in the cash flows must match the treatment of taxes in the discount rate. If, as in Table 4, the debt interest tax benefit is incorporated into the future cash flows, then it is correct to use the after-tax discount rate. If, on the other hand, the cash flows ignore the tax benefits of debt financing, as in Table 2, then the higher before-tax discount rate should be used. The zero NPV results demonstrate that the correct discount rate has been utilized in both cases.

Choice of Discount Rate for EE Cost Effectiveness Evaluations

In evaluating EE cost effectiveness, we discount future utility revenue requirements cash flows. The utility revenue requirements include avoided market energy and capacity purchases, as well as transmission and distribution deferral values, and importantly, they properly reflect the tax deductibility of debt interest. The EE cost-effectiveness evaluation is therefore analogous to the example in Table 4, where the cash flows account for the debt tax shield.

(End of Attachment B)

ATTACHMENT C

ADDRESSING NON-ENERGY BENEFITS IN THE COST-EFFECTIVENESS FRAMEWORK

ATTACHMENT C

ADDRESSING NON-ENERGY BENEFITS IN THE COST-EFFECTIVENESS FRAMEWORK

This paper was prepared by CPUC Energy Division staff, based on research provided by Ed Vine of the California Institute for Energy and the Environment.

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1. Introduction

It is widely argued that there are benefits associated with and attributable to utility demand-side programs beyond direct energy savings. There are three classes of these non-energy benefits (NEBs) based on "beneficiary" or "perspective" (Skumatz et al. 2009). Participant NEBs accrue to the program participants (such as reduced building operating costs, increased value, comfort, health, and safety). Utility NEBs are realized as indirect costs or savings to the utility (such as bill payment improvements, infrastructure savings, etc.). Societal NEBs represent indirect program effects beyond those realized by ratepayers/utility or participants, and they accrue to society at large (such as job creation, tax receipts growth, labor productivity, housing value, neighborhood stability, and reduced emissions and other environmental benefits). This paper considers various methods for addressing NEBs in the CPUC's cost-effectiveness tests for demand-side resources.[1]

A cost-effectiveness test is a test designed to determine whether the benefits of a particular program (or measure, project, or portfolio of programs[2]) outweigh its costs. Cost-effectiveness tests are frequently expressed as a ratio of benefits to costs: a result of greater than one indicates that the benefits outweigh costs, while a result of less than one indicates the reverse. The cost-effectiveness of California utilities' demand side programs is measured using the tests defined in the California Standard Practice Manual (California Energy Commission and California Public Utilities Commission, 2001; hereafter SPM). The SPM describes several tests which measure cost-effectiveness from various perspectives, and the Commission uses various SPM tests to evaluate the utilities' demand-side resources. Those tests are the Total Resource Cost (TRC) test, which has the perspective of the utilities and all their customers, the Program Administrator Cost (PAC) test (the PAC is sometimes referred to as the Utility Cost Test, or UCT), which measures costs and benefits to the program administrator (which is generally the utility), the Ratepayer Impact Measure (RIM) test, which measures the impact on rates, and the Participant test, which looks at the perspective of participating customers[3].

1The Commission is examining other cost-effectiveness issues, such as accounting for market transformation impacts of programs; so-called "spillover" that results when program participants and/or nonparticipants adopt measures without obtaining any customer incentive as a result of some exposure to the incentive programs (initially as they relate specifically to energy efficiency) in Phase IV of its energy efficiency proceeding (R.09-11-014). It should also be noted that this paper does not discuss other potential changes to the current cost-effectiveness framework such as avoided costs, discount rates, or measure lifetimes.

2 Unless specifically noted, we use the following terms interchangeably for this paper - measure, project, program or portfolio of programs – even though we know that there are differences when examined in detail.

3 While the California Demand Response Cost-effectiveness Protocols require calculation of all four SPM tests, a recent demand response decision (D.12-04-045) used only the Total Resource Cost (TRC) test to determine whether each demand response program was cost-effective. The energy efficiency portfolios are evaluated based on a dual test which includes both the TRC and the PAC tests. The Self-Generation Incentive Program uses both

The TRC is seen as having the broadest perspective (it is sometimes described as having a "societal" perspective) in that it includes both the utilities and all its ratepayers. As such, discussions about adding NEBs to the cost-effectiveness tests often center on proposals to modify the TRC test.

Options for addressing NEBs in CPUC cost-effectiveness tests that are examined in this paper include:

- Quantifying and valuing NEBs and including them in the Total Resource Cost (TRC) calculation, which compares avoided energy costs (the benefits) to the total costs of the program, including both participant and utility costs (Section 2);
- Ensuring that NEBs and any costs associated with achieving them are excluded from the TRC (Section 3); and
- Using exclusively the PAC test – which uses the same benefits as the TRC but considers only costs paid by the utility – to evaluate CPUC demand-side program cost-effectiveness (Section 4).

Section 5 identifies (without elaboration) two other possible options for addressing NEBs – one via an adjusted TRC threshold and the other with the development of a societal test.

2. Quantification and Valuation of NEBs in the Relevant Cost-Effectiveness Tests

One option for addressing NEBs would be to include them in the TRC calculation. This section examines the relevant considerations that would need to be addressed to quantify and value NEBs in the TRC, including (a) relevant research into the quantification of NEBs, (b) the additional non-energy costs that may need to be factored into a test that includes NEBs, and (c) examples of including NEBs in cost-effectiveness tests.

An important consideration is that unlike other demand-side resource quantification and valuation efforts (which rely on a variety of tools including modeling, longitudinal bill analysis, and participant and nonparticipant surveys, on-site metering, utility and market costing and cost forecasts, and a host of other more rigorous quantitative methodologies), the quantification and valuation of NEBs rely largely on self-report via survey responses. The reliability of results based on self-report – particularly related to the monetization of qualitative benefits – is the subject of much debate, and the fact that NEBs have a high degree of variability across participants renders the reliable quantification of impacts particularly difficult.

Quantifying Participant, Utility, and Societal NEBs

Participants can realize a variety of NEBs from participation in demand-side programs. Some of the participant NEBs are due to subjective, non-material impacts, such as "increased comfort," while others – such as improved health or increased property value – are difficult to measure and monetize, although they can be quantifiable, using data from the Program Administrators (PAs), secondary data and algorithms found in the literature, and participant surveys (Amann 2006; NMR and Tetra Tech 2011; Skumatz et al. 2009 – see these references for a discussion of the different methods as well as a lengthy list of NEBs). When measured and monetized, participant NEBs have often found to be quite valuable, often exceeding the value of

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the TRC and the Participant Test. Finally, the California Solar Initiative cost-effectiveness evaluation considers all four of the SPM tests.

energy savings,[4] ranging from 50% to 300% of annual household energy bill savings (Amann 2006; NMR and Tetra Tech 2011; Skumatz et al. 2009).

A large share of the NEBs literature in the last decade has focused on bringing more maturity to the methods for measuring participant NEBs (Skumatz et al. 2009). Because these rely on self-report surveys, and represent "hard to measure" benefit categories (comfort, etc.), significant work was needed. More than a dozen measurement approaches with grounding in the academic literature have been studied, and work proceeds on trying to identify methods that are accurate, but also feasible to implement. Each method has pros and cons, and a few studies have compared the performance of different measurement methods. The main purpose of each is to develop monetized estimates of the indirect impacts that can be assigned to the program.

Participant NEBs have been applied to a wide variety of programs – including entire utility portfolios – and NEB results are available for a wide variety of initiatives in the residential, commercial, and multifamily sectors, as well as for renewable, real-time pricing, commissioning, and low-income weatherization programs. Studies of NEBs in these programs have found that the impacts were real, significant and merited continued analysis (Skumatz et al. 2009). The most common, highly valued NEBs varied somewhat by programs and measures. Highly valued residential NEBs tended to include comfort, operations and maintenance, ability to "do good" for the environment, and water savings. Highly valued positive effects for commercial programs tended to include comfort, operations/maintenance/lifetime, "doing good" for the environment, productivity, and performance issues.

In a recent review of participant NEBs for Massachusetts PAs (NMR and Tetra Tech 2011), the authors quantified the NEBs and assessed the *reliability* of the NEB values found in the literature and the extent to which they applied to the PA's low-income and residential programs. They also recommended NEB quantification methods that included deriving values from the literature, from engineering estimates and algorithms, and from data collection through surveys of program participants. They found that they could not recommend quantification for all NEBs for one of several reasons: (1) the NEB was too hard to quantify meaningfully; (2) quantifying the NEB would amount to double counting as the NEB was already accounted for; (3) there was insufficient evidence in the literature for its existence; and (4) the NEB was too intangible. However, they could recommend a long list of NEBs for the low-income and residential programs.

Utilities can also realize a number of NEBs from their energy efficiency programs in the form of financial savings (Skumatz et al. 2009; NMR and Tetra Tech 2011). Energy-efficient technologies often result in reduced energy bills for participants, which can decrease the likelihood that customers experience difficulties with paying their utility bills. In turn, utilities realize financial savings through reduced costs associated with arrearages and late payments, uncollectible bills and bad debt write-offs, service terminations and reconnections, bill-related customer calls, and the bill collections process. Furthermore, utilities may realize savings from their energy efficiency programs due to a reduction in safety-related emergency calls and reductions in energy that is eligible for a rate discount.

NMR and Tetra Tech (2011) found that nearly all utility NEBs resulted from programs targeted to low-income customers. Furthermore, these values were relatively low in value, typically ranging from less than a dollar to nearly $9 per participant. They also noted that utility

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[4] Throughout this paper, when we refer to "energy savings" we are referring not only to energy saved by energy efficiency measures, but also demand reductions from demand response customers and energy generated by customer generation which "saves" the utilities from needing to procure it.

NEBs could be monetized relatively easily from the literature or from algorithms using inputs from the PAs. We are not aware of any regulators specifically including utility NEBs in the TRC.

Finally, the quantification of societal NEBs focuses primarily on environmental and economic impacts, as the remaining societal NEBs are sparsely reported and quantified (e.g., equity benefits or reduced societal disparity for low-income populations). In California, the cost-effectiveness tests used for all demand-side programs currently included an avoided cost of GHG emissions, based on the energy savings of each program. TRC tests that include the value of avoided carbon emissions and/or other avoided externalities are sometimes called "TRC plus C" or "enhanced" TRC tests (LeBaron 2011).

Non-Energy Costs

It is important to consider that, in addition to non-energy *benefits*, there are non-energy costs to consumers of demand side measures that may not always be included in cost-effectiveness calculations. Like non-energy benefits, non-energy costs may be incurred by participants, utilities, or all of society. In California, participant non-energy costs are already factored into Demand Response program cost-effectiveness tests, since those costs are considerable and make up the bulk of the costs of the Demand Response participants costs (most Demand Response programs do not require participants to install equipment).

For example, demand response participants experience significant non-energy costs both before a demand response event is called (e.g., developing a load-shedding plan) and during demand response events (e.g., productivity and comfort losses associated with reduced energy services). Because these costs are difficult to quantify, the CPUC current requires utility to estimate these costs as 75% of the incentives received by participants.

Energy efficiency and distributed generation participants may also experience non-energy costs. For example, two hard-to-quantify costs to the consumer of compact fluorescent light bulbs are the dim light some of them produce when first turned on and the need to dispose of them in special collection locations rather than throwing them in the garbage (due to the danger posed by mercury which they contain). These costs are not included in the participant cost calculation for energy efficiency programs, since it is generally assumed that consumers who install energy efficiency measures gain more from the non-energy benefits then they lose from the non-energy costs.

In California, non-energy costs that are incurred by utilities or by society are not currently included in the TRC calculation (except for GHG emissions and environmental permitting costs such as air and water quality permits embedded in other components of the tests). It is generally assumed that if these costs exist, they are very small. It is known that there are some societal non-energy costs in the form of environmental costs. For example, the mercury contained in compact fluorescents is a cost of Energy Efficiency programs. Other environmental costs are incurred by society if demand response customers use backup diesel generators during demand response events, or when birds are injured by wind turbines. However, these environmental costs are relatively tiny compared with the environmental benefits of the avoided energy and capacity associated with demand-side programs.

Examples of Including NEBs in Cost-Effectiveness Tests

In a recent survey of 41 states, 12 (or 29%) states indicated that they included NEBs in their cost-benefit tests (Kushler et al. 2011). Of those using NEBs, 7 states included water and

other fuel savings, 2 reduced maintenance (Vermont and Washington), and one had a general adder (Colorado); no states included health, comfort, or improved productivity. Only 13 (or 32%) states indicated that they included environmental externality benefits in their cost-benefit tests, and another 5 states (12%) included "other societal benefits" (excluding environmental benefits) in their cost-benefit tests (Kushler et al. 2011).

In another recent review of selected states5, NEBs were included in TRC calculations, usually as an "adder" to the benefits side (Daykin et al. 2011), as shown in Table 1.

Table 1. TRC Calculation Requirements in Selected States

State	Year	Non-Energy Benefits
Colorado	2008	10% adder (25% for low-income programs)
Iowa	1999	10% adder for electric; 7.5% adder for gas
Maine	2009	All quantifiable NEBs, including deferred replacement costs
Massachusetts	2009	All costs of complying with foreseeable environmental regulations
Oregon	2008	Carbon ($15/ton); 10% adder
Washington	2008	10% adder

Source: Daykin et al. 2011

Finally, British Columbia's Utility Commission Act on Demand-Side Measures Regulation (effective June 1, 2009) requires the TRC to account for NEBs in the following manner for each measure (British Columbia 2008; Muncaster 2011):

- Via quantification (i.e., acceptable evidence of the existence and size of the NEB), or
- Via a deemed adder for programs or measures where no quantification is available (for example, a program with $100,000 in energy benefits and a 15% deemed adder, has $115,000 in total deemed benefits).

In California, NEBs are calculated for Low Income programs, but are used in non-SPM cost-effectiveness tests which have been designed specifically for Low Income programs. NEBs are not currently included in any of the cost-effectiveness tests used for non-Low Income Energy Efficiency, or any other demand-side programs.

3. Removing All NEB-related Costs from the TRC Participant Costs

Another method for addressing NEBs in CPUC cost-effectiveness tests is to ensure that only costs or benefits related to energy savings are included in the TRC calculation, so that any participant costs associated with achieving NEBs are omitted and the TRC calculation becomes purely energy-related cost-effectiveness test. The CPUC currently attempts to separate the various elements of energy efficiency program participant costs. For example, if people who have their homes retrofitted are motivated to a large degree by benefits other than saving money on their utility bill, such as increased comfort, desire to be "green," and improved aesthetics, we attempt to calculate that portion of their retrofit expenditure which was incurred with the goal of achieving those particular benefits and take that portion of the project cost out of the TRC participant costs. This is the approach is taken in the calculation of "net-to-gross" ratios which

[5] **BC Hydro** and **New Hampshire** also use an adder to reflect all NEBs (Skumatz et al. 2009). And **New Mexico** allows avoided carbon emissions to be included in the TRC (personal communication with Howard Geller, Southwest Energy Efficiency Project, January 21, 2012).

measure the extent to which incentive programs *cause* participants to install energy efficient equipment, an analysis that is performed to eliminate "free-ridership" (the extent to which customers would have installed the equipment even in the absence of an incentive) from the cost-effectiveness calculation. The net-to-gross calculation may already be resulting in reasonably accurate accounting of the cost of California's energy efficiency programs and elimination of that portion of program costs that do not result in energy savings. However, the net-to-gross calculation may not be completely accounting for the costs associated with NEBs for energy efficiency programs, and is not currently applied to other demand-side programs.

In addition it has been recognized that it is important to only count the energy efficiency *incremental* costs to upgrade to higher efficiency models of the products the customer would have purchased without the program intervention in the TRC. Some states include "all costs regardless of who pays," and include all the costs of the equipment upgrade. This practice results in the inclusion of costs that are not affiliated with the energy efficiency decision. Similarly, labor costs should include only those costs, if any, associated with installing the more energy efficient version of a product (Hall 2012).

4. Substituting the PAC for the TRC

A third alternative for addressing the fact that NEBs are not included in the current TRC test would be to cease to use the TRC and rely solely on the PAC test. The TRC is intended to show whether and to what degree a program is cost-effective from the point of view of the ratepayers (program participants and nonparticipants) and the utility, so its cost includes full cost of the measure, paid by the participant and/or the utility. In contrast, the PAC uses the same set of benefits as the TRC, but its cost calculation only includes incentives paid by the utility and no participant costs (see Table 2 for the various components of the TRC and PAC tests).

Table 2. PAC and TRC Tests in California

Test	Benefits	Costs
TRC	• Avoided supply costs for transmission, distribution and generation • Avoided cost of GHG emissions	• Program administration • Measure costs (incremental equipment costs paid by participant, utility, or both)
PAC	• Avoided supply costs for T&D and generation • Avoided cost of GHG emissions	• Program administration • Incentives paid to participants.

Consider programs whose participant costs are much greater than any available incentives received (e.g., energy efficiency programs such as Energy Upgrade California, and demand response programs such as Permanent Load Shifting). These programs usually have much lower benefit-cost ratios on the TRC than on the PAC, but it may be that a portion of the participant cost included in the TRC is incurred not to obtain energy savings, but to receive NEBs. For example, utility customers may invest in whole house retrofits to receive additional benefits beyond energy savings that are not included in TRC calculations (reducing noise levels and temperature gradients throughout their homes, to be seen as "greener," etc.). To the extent that the TRC includes the full cost of the measure, then arguably all of the realized benefits – energy and non-energy – should also be included in the test. Since the PAC excludes the participant cost, using this test obviates the need to identify or quantify other potential benefits

that the participant may be deriving from the measure.

Neme and Kushler (2010) also point out that using the TRC to determine the cost-effectiveness of demand side programs results in inconsistent treatment of energy reduction and some forms of customer generation resources, since the TRC attempts to include all participant costs, while other types of distributed generation resources that utilities procure (e.g., power purchased from CHP systems) do not include a payment for the customer costs. When procuring those other resources, what the regulator looks at is the 'price paid' for the resource. Similarly, the "cost" in the PAC is essentially the 'price paid' for the resource (via the incentive payment and program administration costs).

Replacing the TRC with the PAC may have certain advantages. The primary advantage is the relative ease of implementation. PAC benefit cost ratios are already routinely filed in CPUC proceedings which require cost-effectiveness analysis. Another advantage is that it is a simpler and less costly alternative to modifying the TRC.

However, there are some disadvantages to replacing the TRC with the PAC test. The PAC measures cost-effectiveness only from the utility perspective, and cannot fully account for many of the benefits (and costs) of demand-side programs, including those benefits which may provide customer motivation to participate in these programs, such as non-monetized environmental benefits. Also, if budgets are limited and only the most cost-effective programs within a certain budget range are to be approved, using the PAC rather than the TRC as a basis for decision-making may not result in the most optimal results, from a combined ratepayer and utility perspective. This would create a significant policy dilemma – if customers are willing to invest in a technology because they perceive there to be large non-energy benefits, is it necessarily good public policy to incentivize that investment?

The answer depends largely on who accrues those non-energy benefits – the customer, the utilities, or society as a whole. It may be difficult for the CPUC to determine under what circumstances ratepayer money should be used to provide incentives to those ratepayers who choose to participate in certain programs. In California, it is generally agreed that it is appropriate to use ratepayer funds to improve the health, comfort and safety of low income customers, but determining policies when higher-income customers are benefiting is likely to be more difficult.[6]

5. Other Options

There are several other options for addressing NEBs in cost-effectiveness tests that will not be developed in this paper but are worthy of mention. One is to simply lower the benefit-cost score needed to be considered cost-effective. This approach has the advantage of being simple to administer, but its disadvantage is that it is a blunt, simplistic solution to the problem. Each measure has its own unique list of hard-to-quantify benefits and costs, yet one number is used for all (and determining the correct number may prove difficult). This approach may also cause public confusion in that it appears to approve "failing" programs (i.e., programs with calculated net benefits of less than 1.0). This is similar to valuing NEBs, as discussed in Section

6 In a recent survey of 41 states on their use of cost-effectiveness tests (Kushler et al. 2011), the primary test used in those states was: TRC (29 states, 71%), Societal (6 states, 15%), UCT/PAC (5 states, 12%), and RIM (1 state, 2%). There are a few exceptions. In 2009, Utah required all programs to pass the PAC test, rather than the TRC – primarily for screening programs (Daykin et al. 2012). And in 2008, Michigan passed Public Act 295, adopting the PAC as the cost-effectiveness screening test.

2, except that this method avoids the expense associated with customer surveys and other research required to attempt to quantify the various NEBs.

Another approach would be to develop a societal test, as described in the SPM as a variation of the TRC test, that includes NEBs and uses a societal discount rate. This test would be available for decision-makers in addition to the TRC, which could still be refined as needed to ensure that it only costs and benefits associated with energy savings as described in Section 3, and the PAC.

6. Comparing the Different Options

Table 3 below provides a comparative example of a project analysis which considers the various alternatives discussed in this paper. The "TRC Participant Cost Adjusted" column takes into account decreased participant costs, based on an estimate that 50% of the benefits of the project were incurred for "non-energy reasons." The "TRC w/ NEBs" column adds an estimate of $6000 as the value of this participant's non-energy benefits. The "net benefits" row shows that, in this example, the project is considered cost-effective based on the PAC, or on a TRC which is adjusted either by adding NEBs or decreasing participant costs, even though the project would not be considered cost-effective using a traditional TRC test.

The difficulty with this analysis is, of course, the difficulty of estimating reasonable values for either participant NEBs or the participant's motivation for investment, especially for large programs involving many different types of participants. For example, in the table below, the 50% cost adjustment is applied to the total measure cost ($7,500) rather than only to the participant's out-of-pocket costs ($5000). Customer surveys have to be precisely worded and carefully interpreted to ensure that the resulting attributions are correctly understood and applied.

Table 3. Example of Fixes to TRC – Home Performance*

	Scenario	TRC Today	Participant Cost Adjusted TRC	TRC with NEBs	PAC
Costs					
Measure Costs	$7,500				
Rebate	33% - $2,500	$2,500	$2,500	$2,500	$2,500
Participant	67% - $5,000	$5,000	$5,000	$5,000	
Administration		$1,500	$1,500	$1,500	$1,500
Customer Attribution of Costs					
Energy Reasons	50%				
Non-Energy Reasons	50%				
Cost Adjustment	($3,750)		- $3,750		
Total Costs		$9,000	$5,250	$9,000	$4,000
Benefits					
Energy-Avoided Costs	$6,000	$6,000	$6,000	$6,000	$6,000

Non-Energy	$6,000			$6,000	
Total Benefits		$6,000	$6,000	$12,000	$6,000
Net Benefits		-$3,000	$750	$3,000	$2,000
		FAIL	**PASS**	**PASS**	**PASS**

*See Kushler (2011)

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(End of Attachment C)