Energy and Environmental Economics, Inc

Energy Efficiency Avoided Costs 2011 Update

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Table of Contents

Overview 2

Natural Gas Avoided Cost Updates 4

Overview of Electricity Avoided Cost Components 6

Avoided Cost Methodology 11

- Generation Energy 11
  - Determination of energy market values 12
  - Hourly Shaping of Energy Costs 15
- Generation Capacity 16
  - Generation resource balance year 16
  - CT dispatch 17
  - Hourly allocation of capacity value 19
  - Temperature effect on unit performance 19
  - Planning reserve margin and losses 22
- Ancillary Services (AS) 23
- T&D Capacity 23
  - Hourly allocation of T&D capacity cost 26
  - T&D adjustment factors 28
- Environment 28
- Avoided Renewable Purchases Adder 31

Comparison of Generation-Related Avoided Cost Values 35

Comparison of the Updated EE Avoided Costs to 2010-2012 EE Avoided Costs 38

Key Data Sources and Specific Methodology 45

- Power plant cost assumptions 45
- Hourly Allocation of Generation Capacity Value 45
- Calculation of the T&D Capacity Allocators 48
- Generation Loss Factors 48
- Climate Zones 50

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:

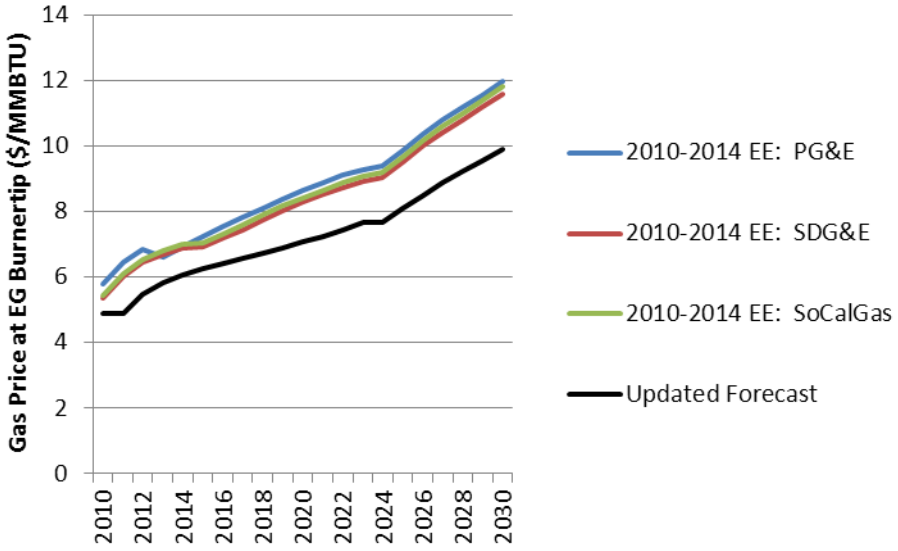
1. T&D method left unchanged, but T&D avoided cost levels updated to reflect more recent utility filings
2. Gas forecast lowered to reflect market conditions at the time of the DR proceeding (December 2010.) The gas forecast affects both electricity cost determination and gas avoided procurement costs.

[2] See D. 10-12-024

Natural Gas Avoided Cost Updates

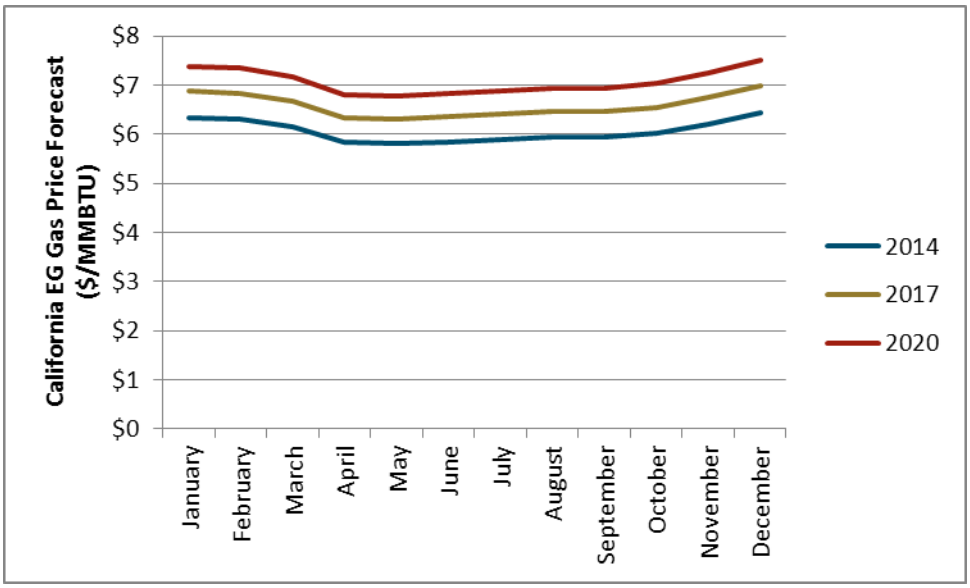
E3 has constructed the natural gas commodity price forecast using NYMEX Henry Hub futures through 2022 updated in December 2010, plus average basis differentials for delivery from Henry Hub to the utility local transmission system (trading through 2015).. After 2022, an average of three fundament price 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

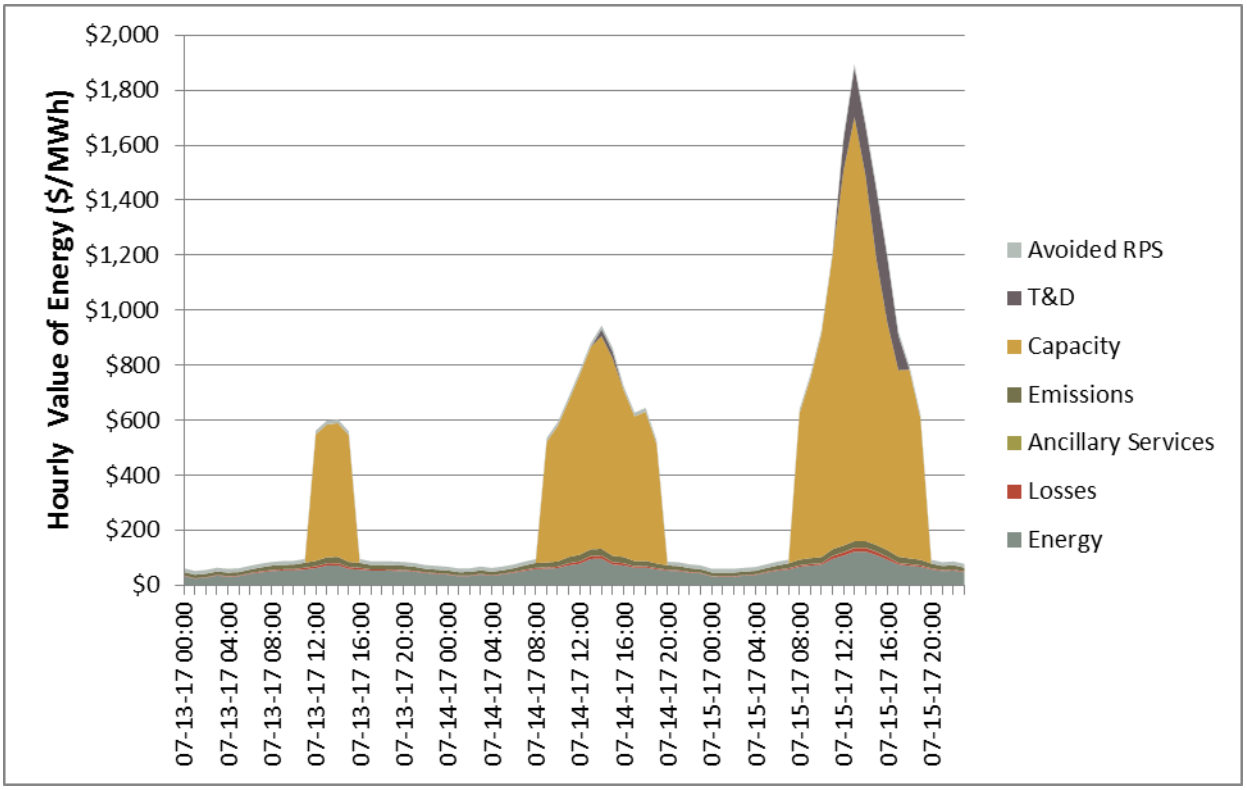


Figure 4 shows average monthly value of electricity reductions, revealing the seasonal characteristics of the avoided costs. The energy component dips in the spring, reflecting low energy prices due to increased hydro supplies and imports from the Northwest; and peaks in the summer months when demand 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

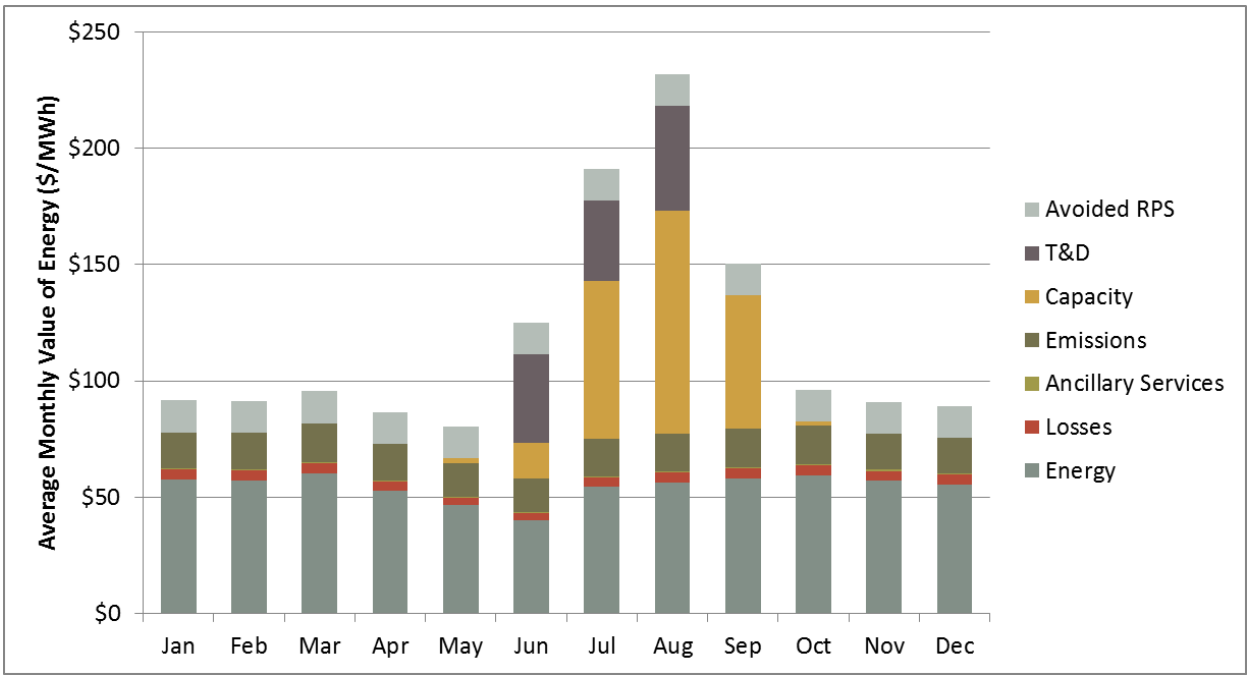
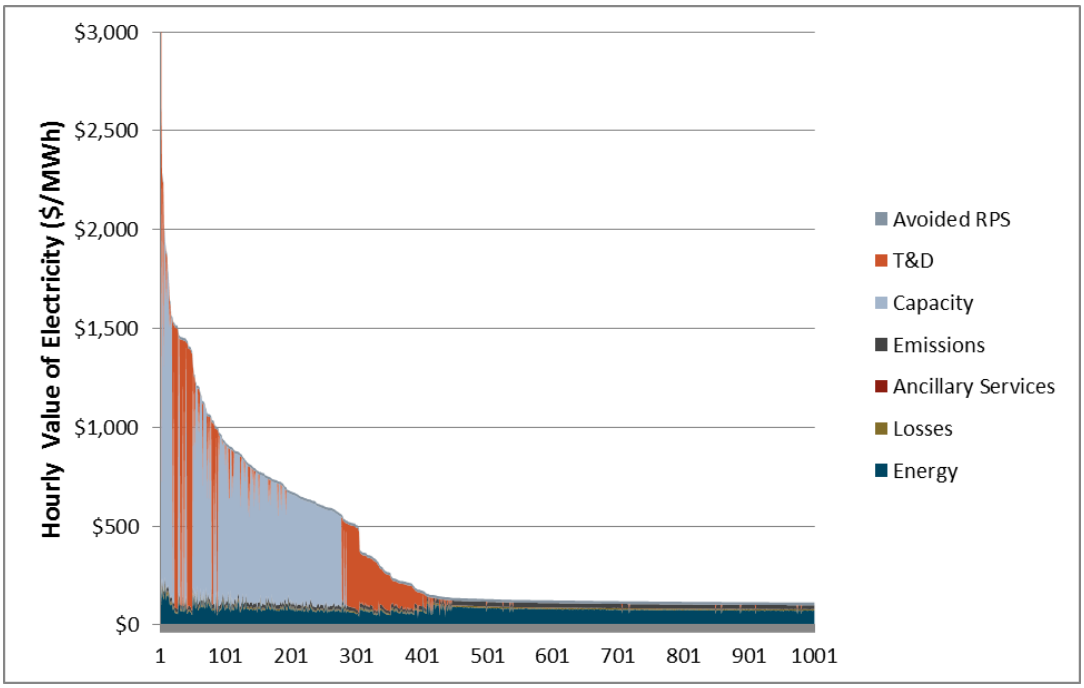


Figure 5 shows the components of value for the highest value hours in sorted order of cost. This chart shows the relative contribution to the highest hours of the year by component. Note that most of the high cost hours occur in approximately the top 200 to 400 hours—this is because most of the value 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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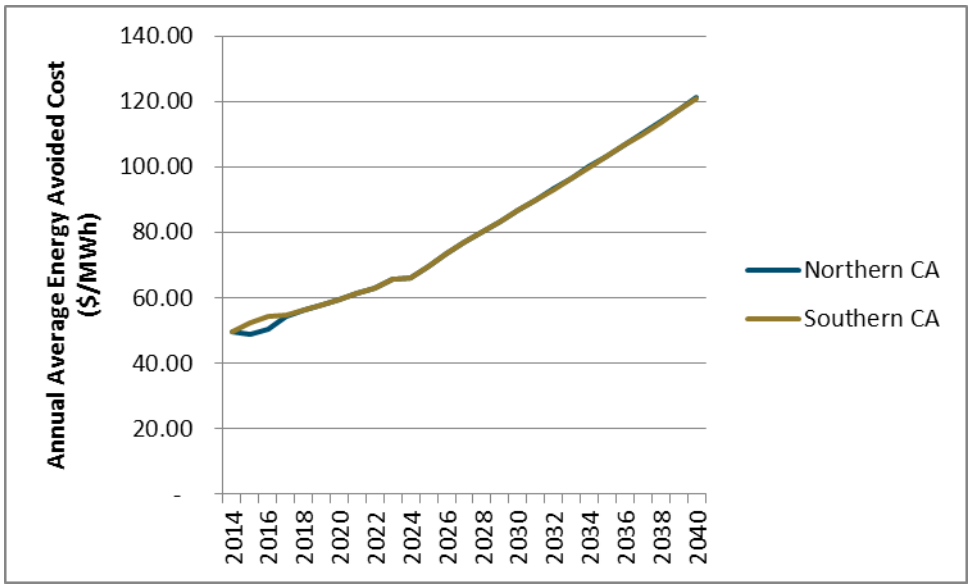
[4] The actual process steps for determining the calibration factor for each year (and therefore the real-time and day-ahead market prices) are listed below.

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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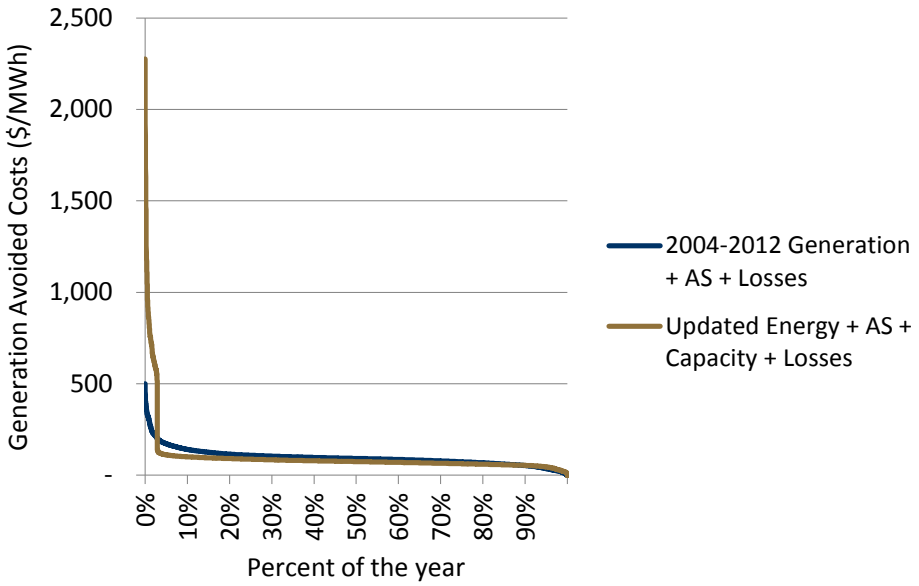
4. Calculate capacity cost
    a. Multiply the real-time 2010 hourly price shape by the adjusted annual day ahead price
    b. Dispatch a new CT against the hourly prices in Northern and Southern CA from 4a to determine real time dispatch revenue in Northern and Southern CA (Figure 6)
    c. Calculate 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

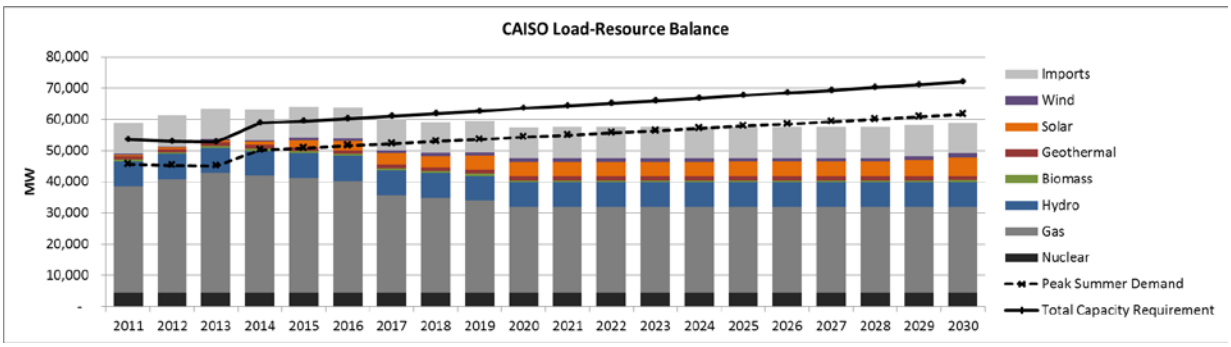
Generation capacity for this update is calculated using the DR method, updated with 2010 input data. The method assumes that in the resource balance year and beyond, the value of capacity will equal the fixed cost of a new CT less the net revenues that the CT would attain from the selling to the real-time 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

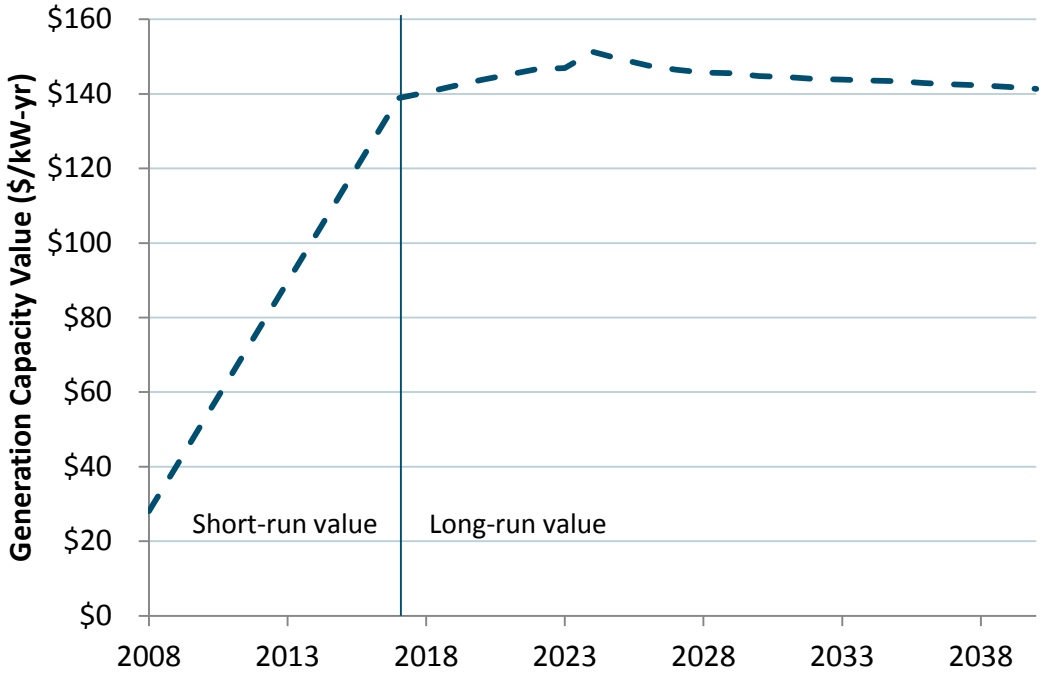
To determine the long-run value of capacity, the avoided cost model performs an hourly dispatch of a new CT to determine energy market net revenues. The CT's net margin is calculated assuming that the unit dispatches at full capacity in each hour that the real-time price exceeds its operating cost (the 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.

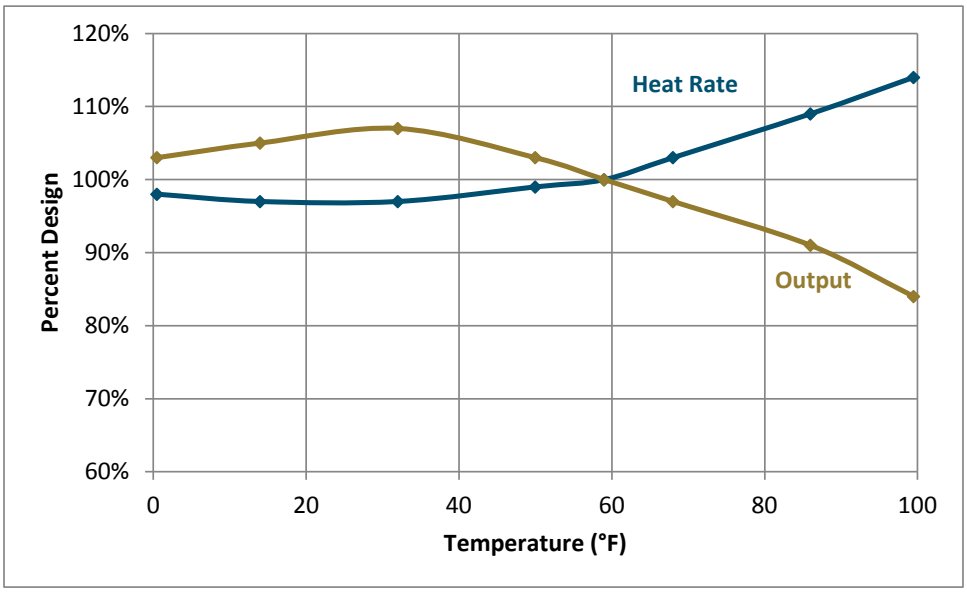
Temperature effect on unit performance

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.

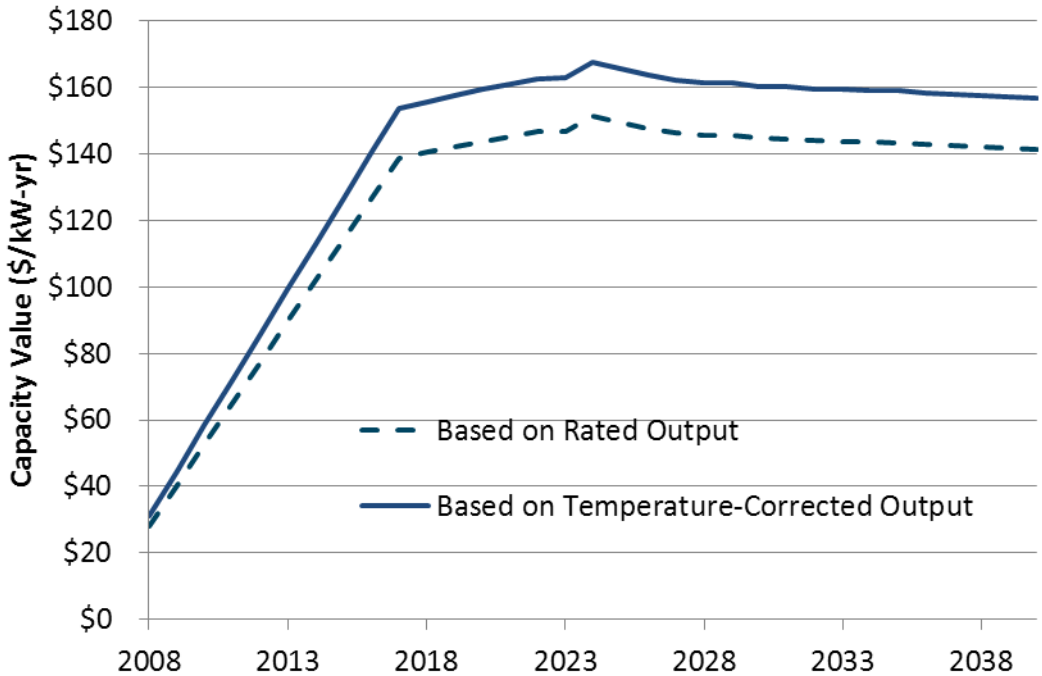
- In the calculation of the CT's dispatch, the heat rate is assumed to vary on a monthly basis. In each month, E3 calculates an average day-time temperature based on hourly temperature data throughout the state and uses this value to adjust the heat rate—and thereby the operating cost—within that month.

- 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

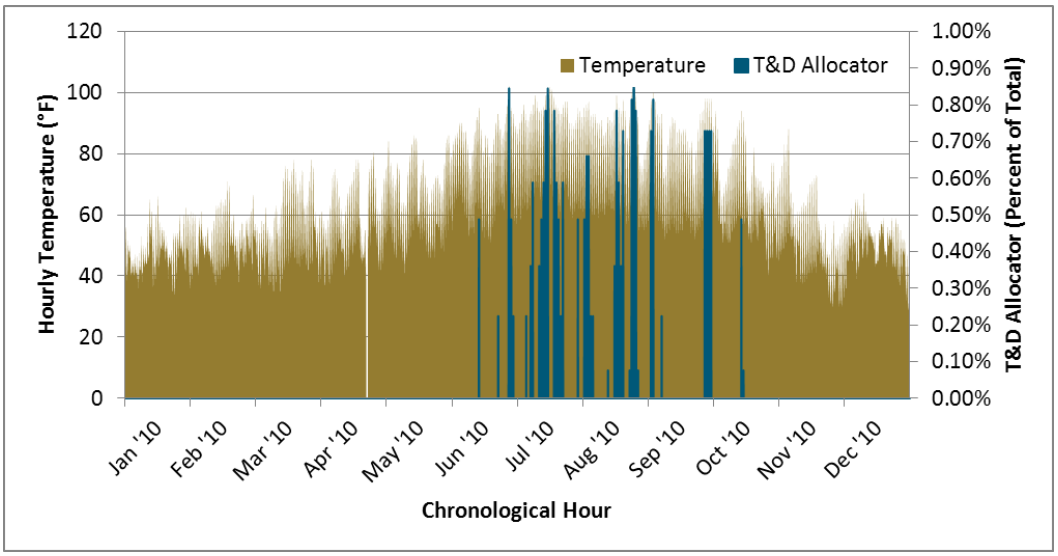
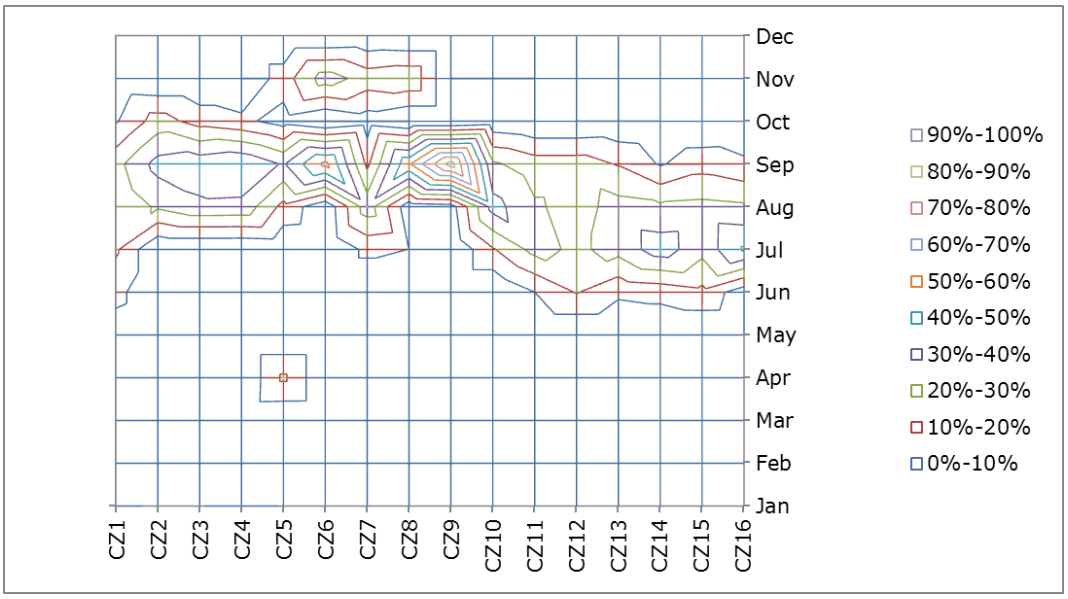


Figure 13. Monthly allocation of T&D capacity value across the sixteen climate zones.



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

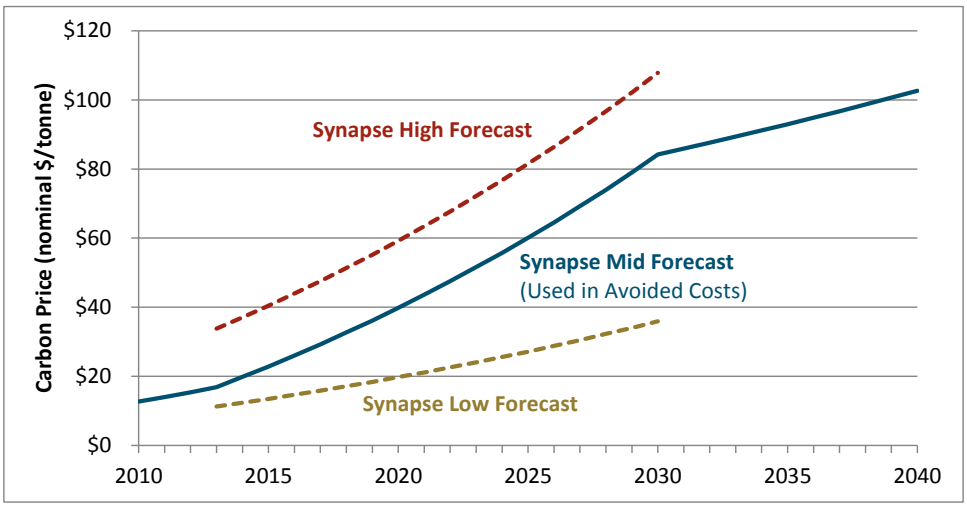
The environmental component is an estimate of the value of the avoided CO2 emissions. While there is not yet a CO2 market established in the US, it is included in the forecast of the future. While there is some probability that there will not be any cost of CO2, that the likelihood of

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

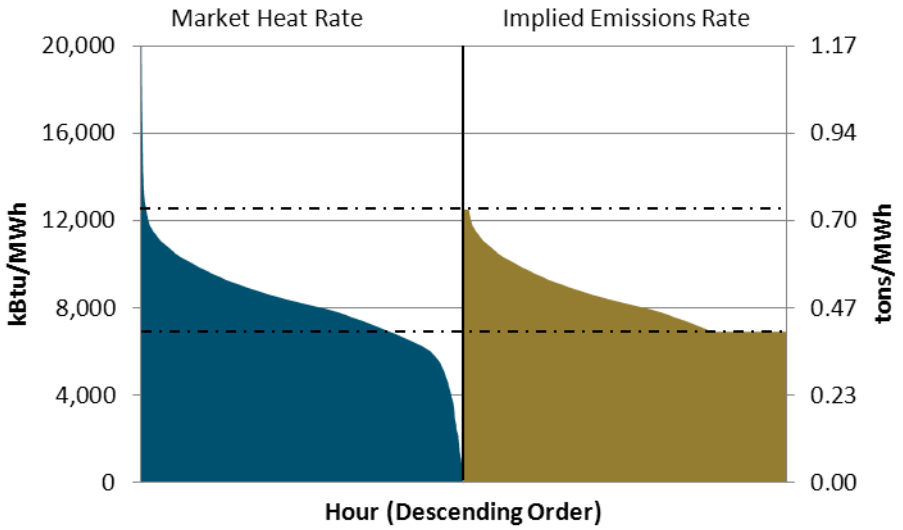
assumed CO2 prices. This method was developed in October 2011 for the 2011 MPR adopted in December 2011 and is not currently used in the avoided cost methodology. As CARB further defines and implements GHG regulations, it is reasonable to expect that the cost of carbon will be reflected in the forward 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

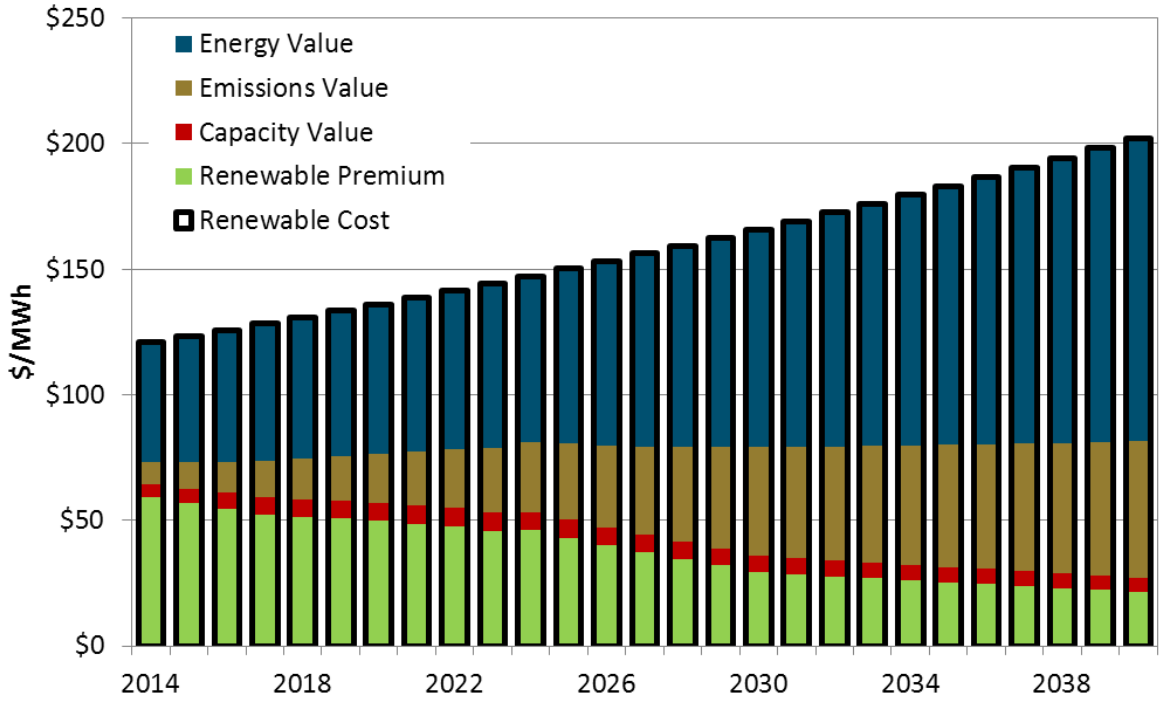
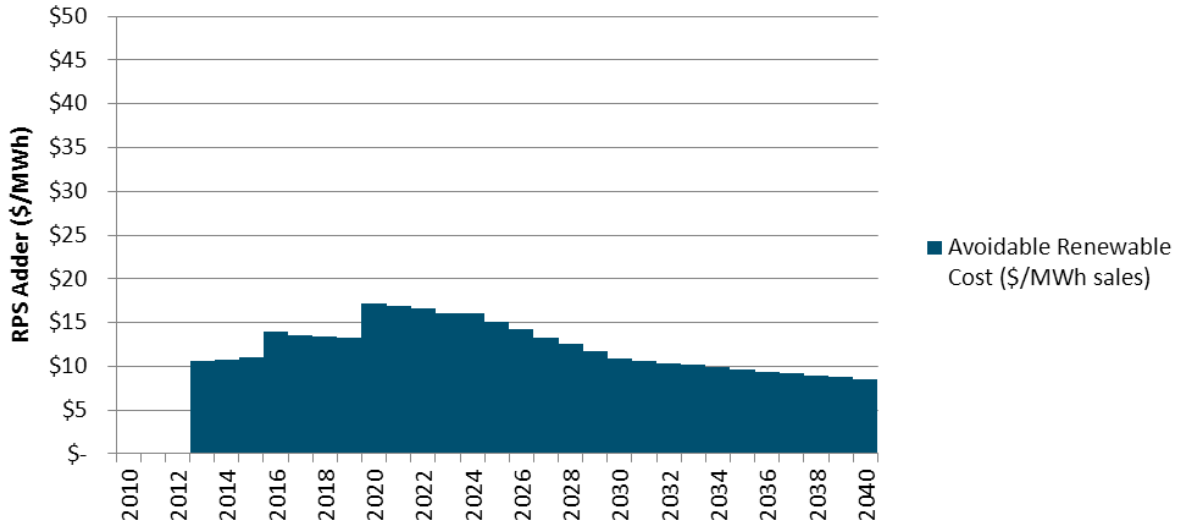


Figure 17: Annual RPS Adder



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

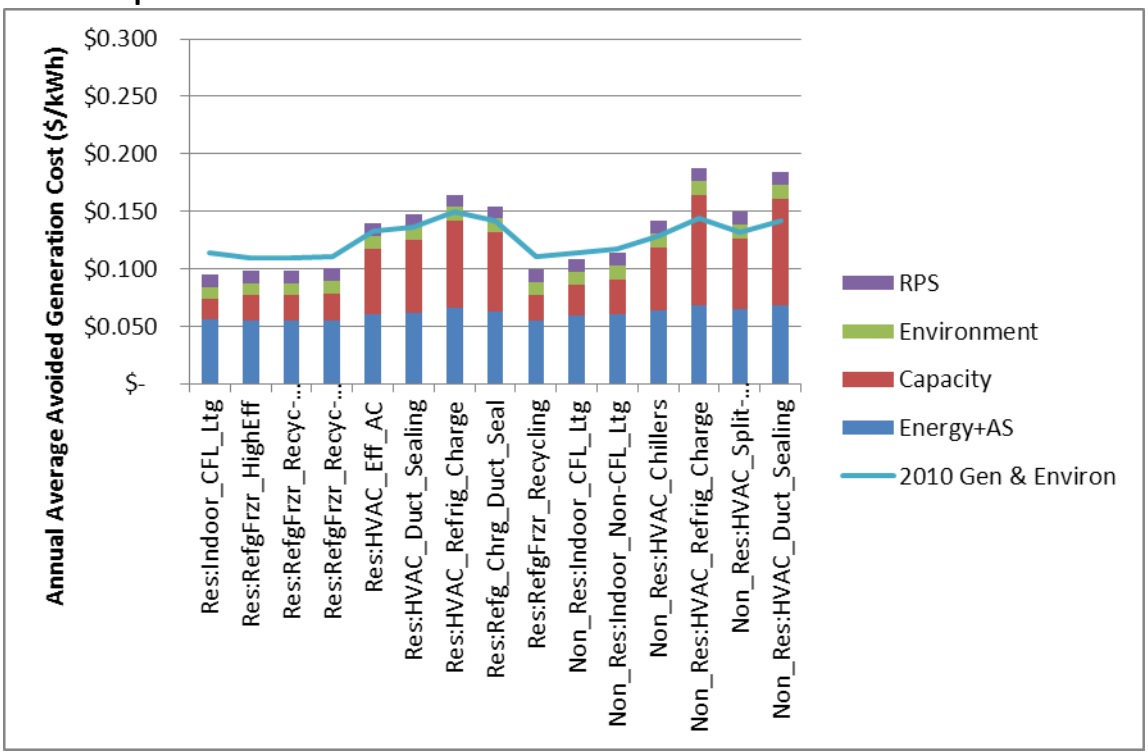
This section evaluates how the changes to generation-related avoided costs affect the avoided cost savings attributed to EE measures. We limit the comparison to the generation-related avoided costs (T&D excluded), because they comprise the largest changes.

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.

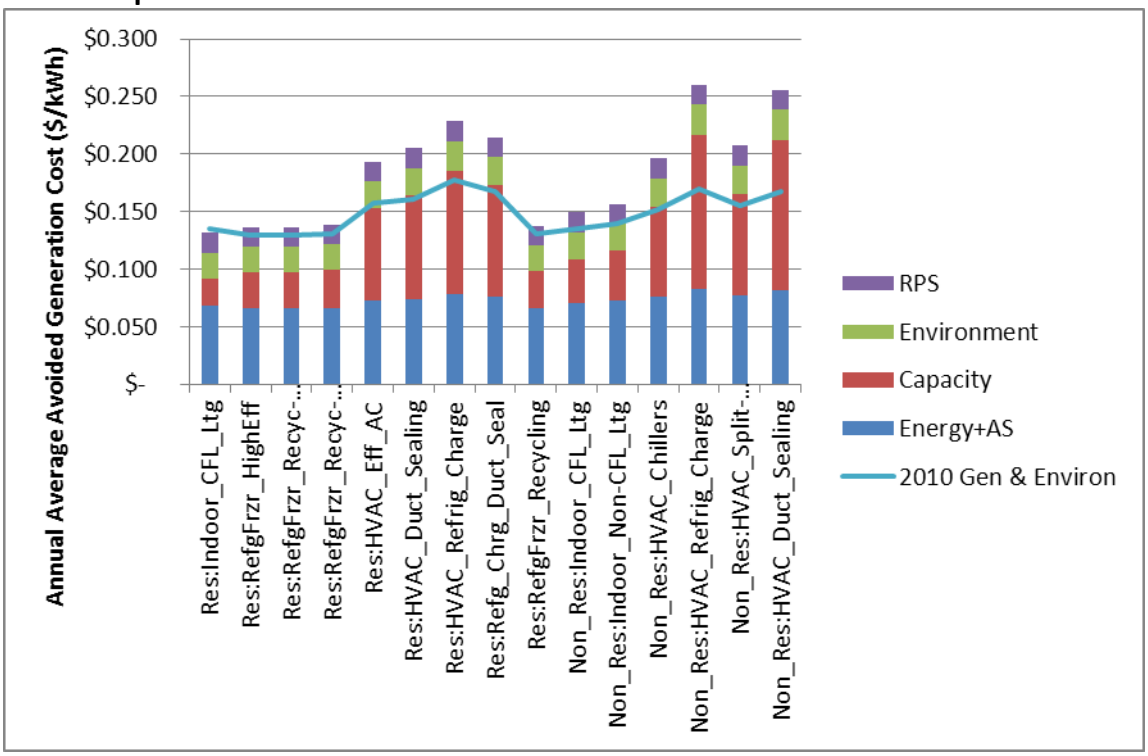
The figures for Northern California show that the updated avoided costs for lighting and refrigeration are lower in 2014, while HVAC is higher. In 2020, the updated avoided costs have lighting at roughly the same level as the 2010-2012 avoided costs, while HVAC is substantially higher.

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.

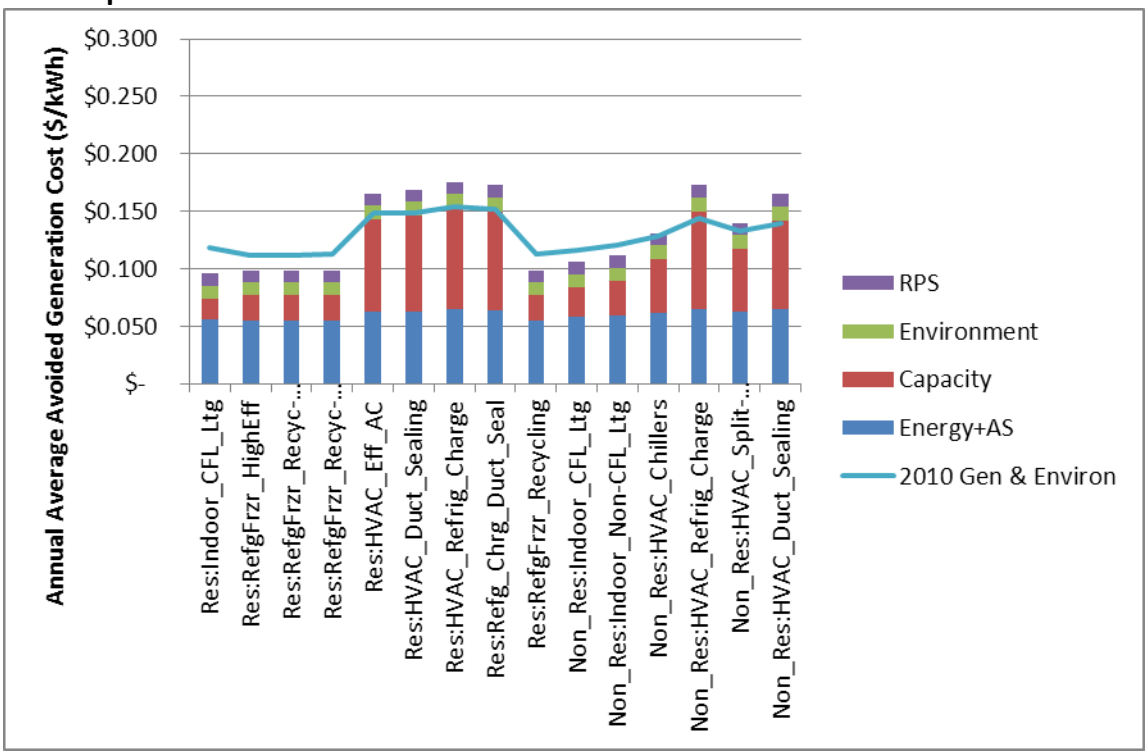
PG&E Shapes: 2014



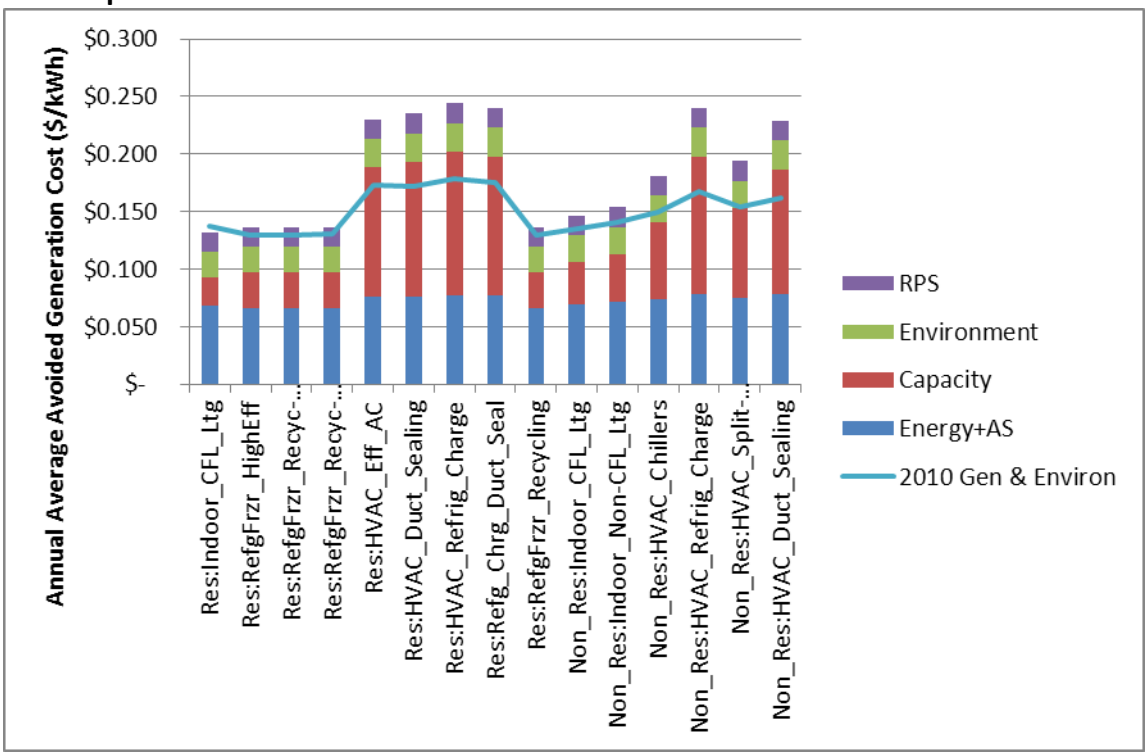
PG&E Shapes: 2020



SCE Shapes: 2014



SCE Shapes: 2020

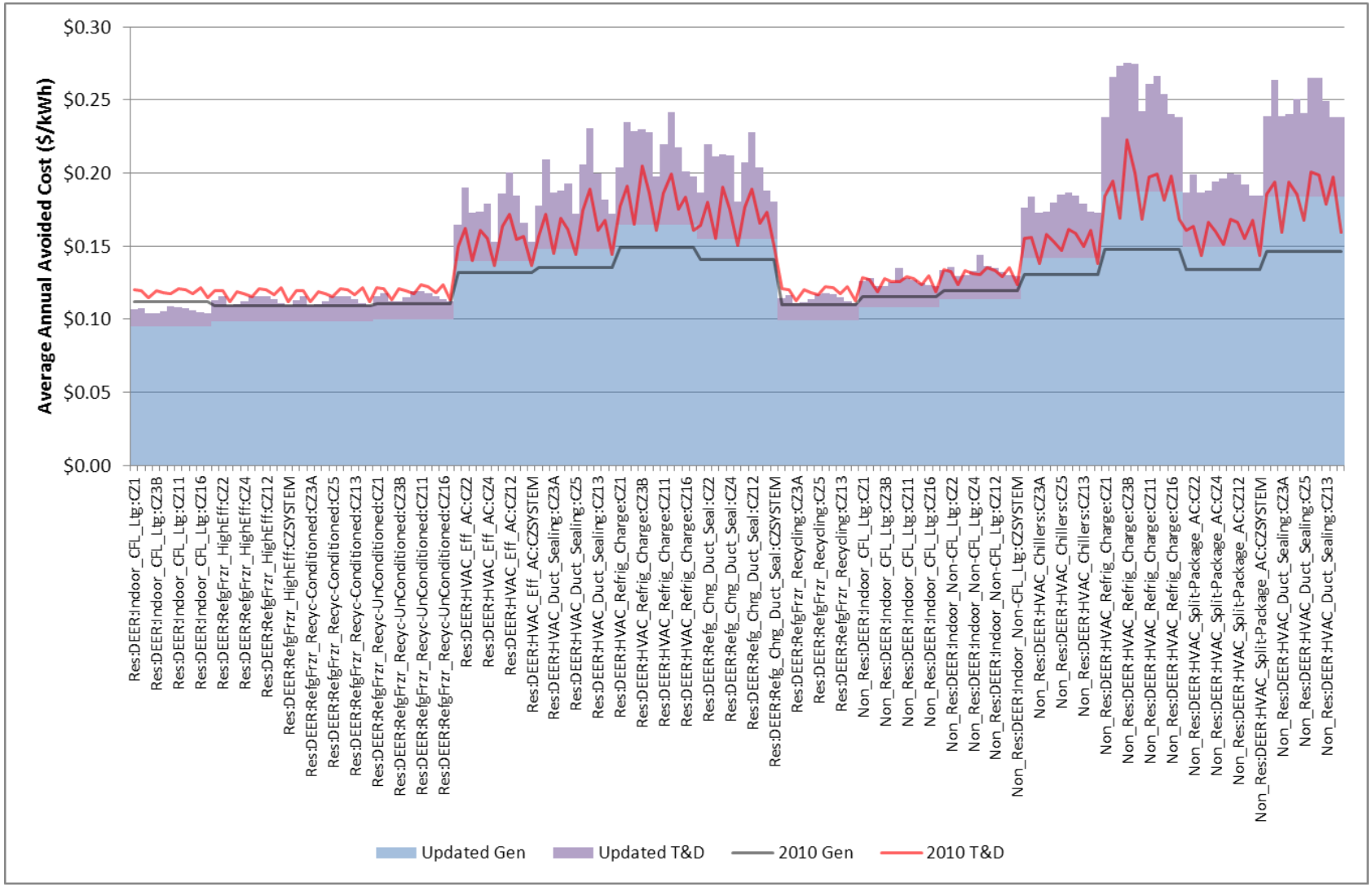


Comparison of the Updated EE Avoided Costs to 2010-2012 EE Avoided Costs

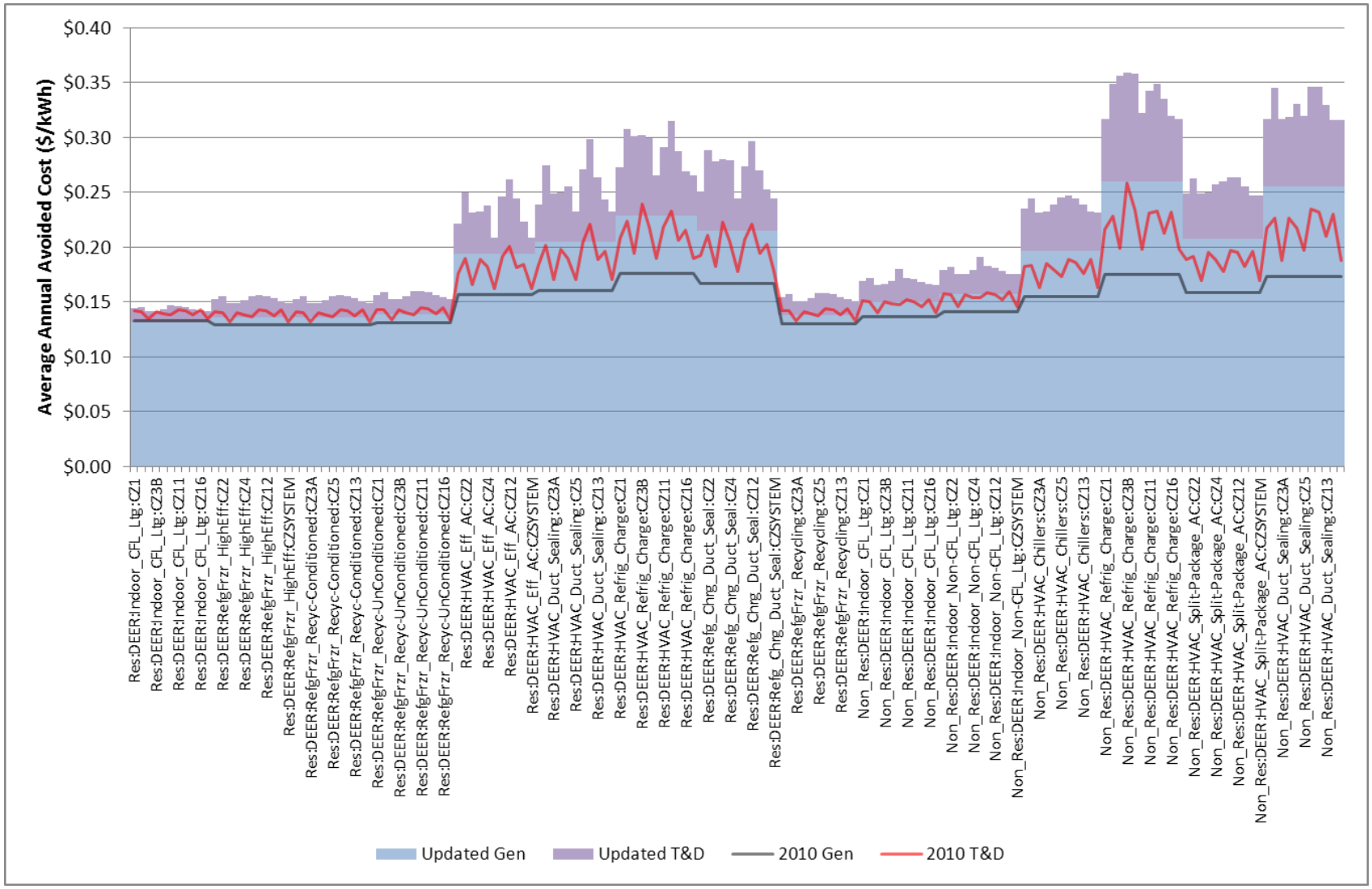
Shown in this section are the total annual average avoided costs for DEER measures by climate zone. The avoided costs for generation (Gen) and transmission and distribution (T&D) are plotted separately. The 2010-2012 EE annual average avoided costs for each DEER measure are shown as stacked lines. 2010 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.

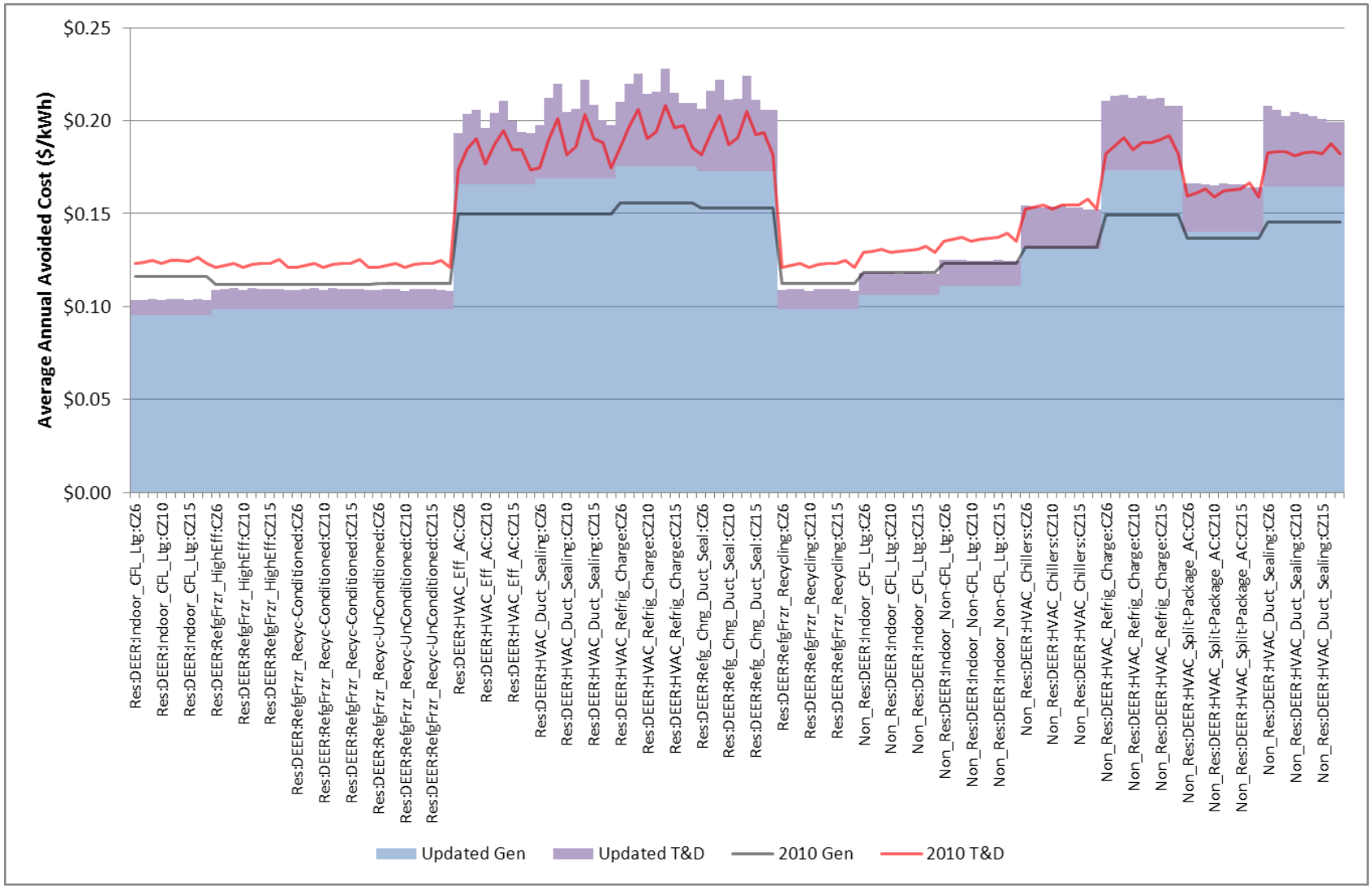
PG&E 2014


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
Res:DEER:Indoor_CFL_Ltg:CZ6
Res:DEER:Indoor_CFL_Ltg:CZ10
Res:DEER:Indoor_CFL_Ltg:CZ15
Res:DEER:RefgFrzr_HighEff:CZ6
Res:DEER:RefgFrzr_HighEff:CZ10
Res:DEER:RefgFrzr_HighEff:CZ15
Res:DEER:RefgFrzr_Recyc-Conditioned:CZ6
Res:DEER:RefgFrzr_Recyc-Conditioned:CZ10
Res:DEER:RefgFrzr_Recyc-Conditioned:CZ15
Res:DEER:RefgFrzr_Recyc-UnConditioned:CZ6
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Res:DEER:HVAC_Refrig_Charge:CZ6
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Res:DEER:RefgFrzr_Recycling:CZ15
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Non_Res:DEER:Indoor_Non-CFL_Ltg:CZ6
Non_Res:DEER:Indoor_Non-CFL_Ltg:CZ10
Non_Res:DEER:Indoor_Non-CFL_Ltg:CZ15
Non_Res:DEER:HVAC_Chillers:CZ6
Non_Res:DEER:HVAC_Chillers:CZ10
Non_Res:DEER:HVAC_Chillers:CZ15
Non_Res:DEER:HVAC_Refrig_Charge:CZ6
Non_Res:DEER:HVAC_Refrig_Charge:CZ10
Non_Res:DEER:HVAC_Refrig_Charge:CZ15
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Non_Res:DEER:HVAC_Split-Package_AC:CZ10
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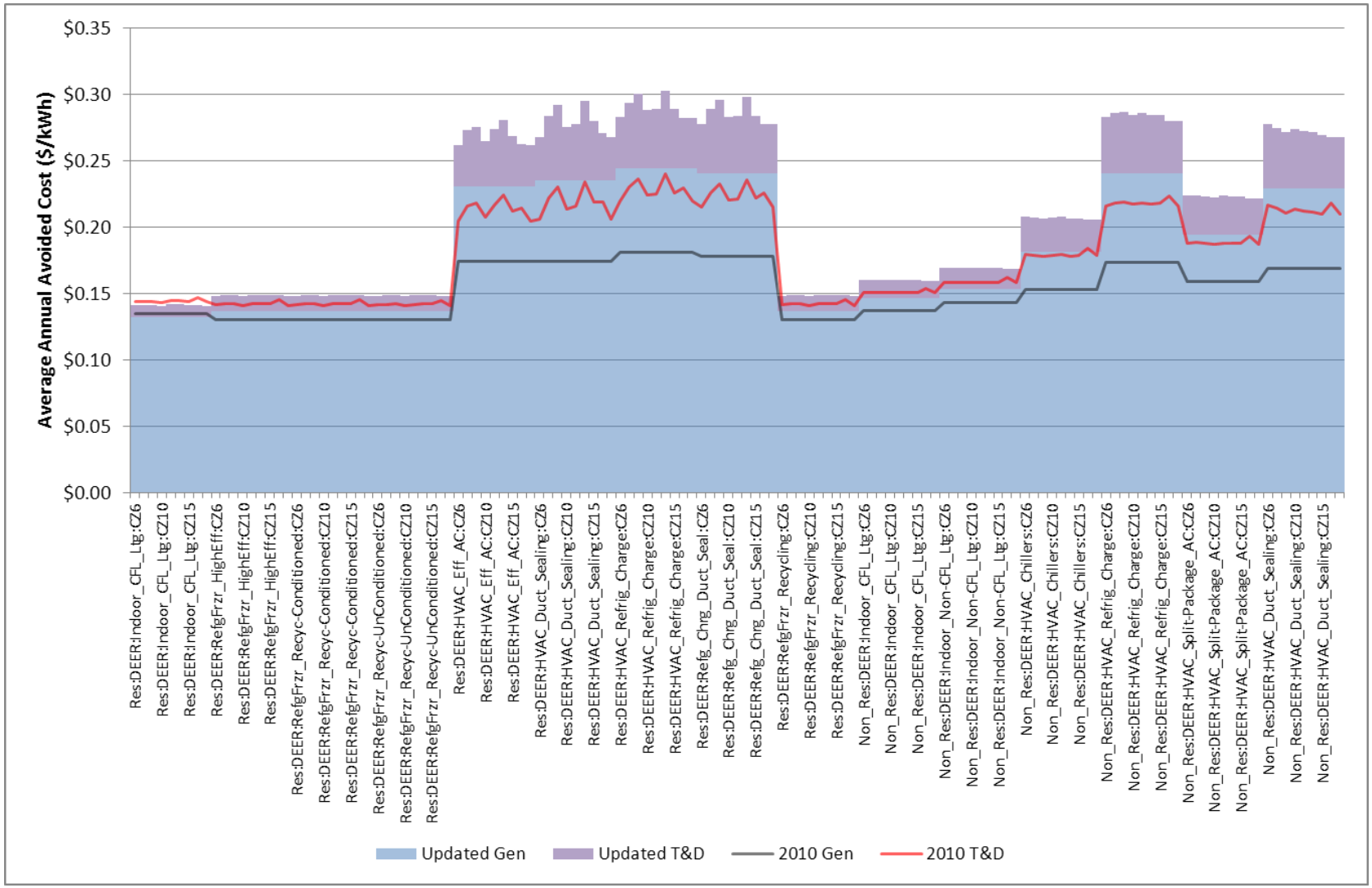
Non_Res:DEER:HVAC_Duct_Sealing:CZ10
Non_Res:DEER:HVAC_Duct_Sealing:CZ15
Updated Gen
Updated T&D
2010 Gen
2010 T&D

SCE 2020


Average Annual Avoided Cost ($/kWh)
$0.35
$0.30
$0.25
$0.20
$0.15
$0.10
$0.05
$0.00
Res:DEER:Indoor_CFL_Ltg:CZ6
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Res:DEER:RefgFrzr_Recycling:CZ10
Res:DEER:RefgFrzr_Recycling:CZ15
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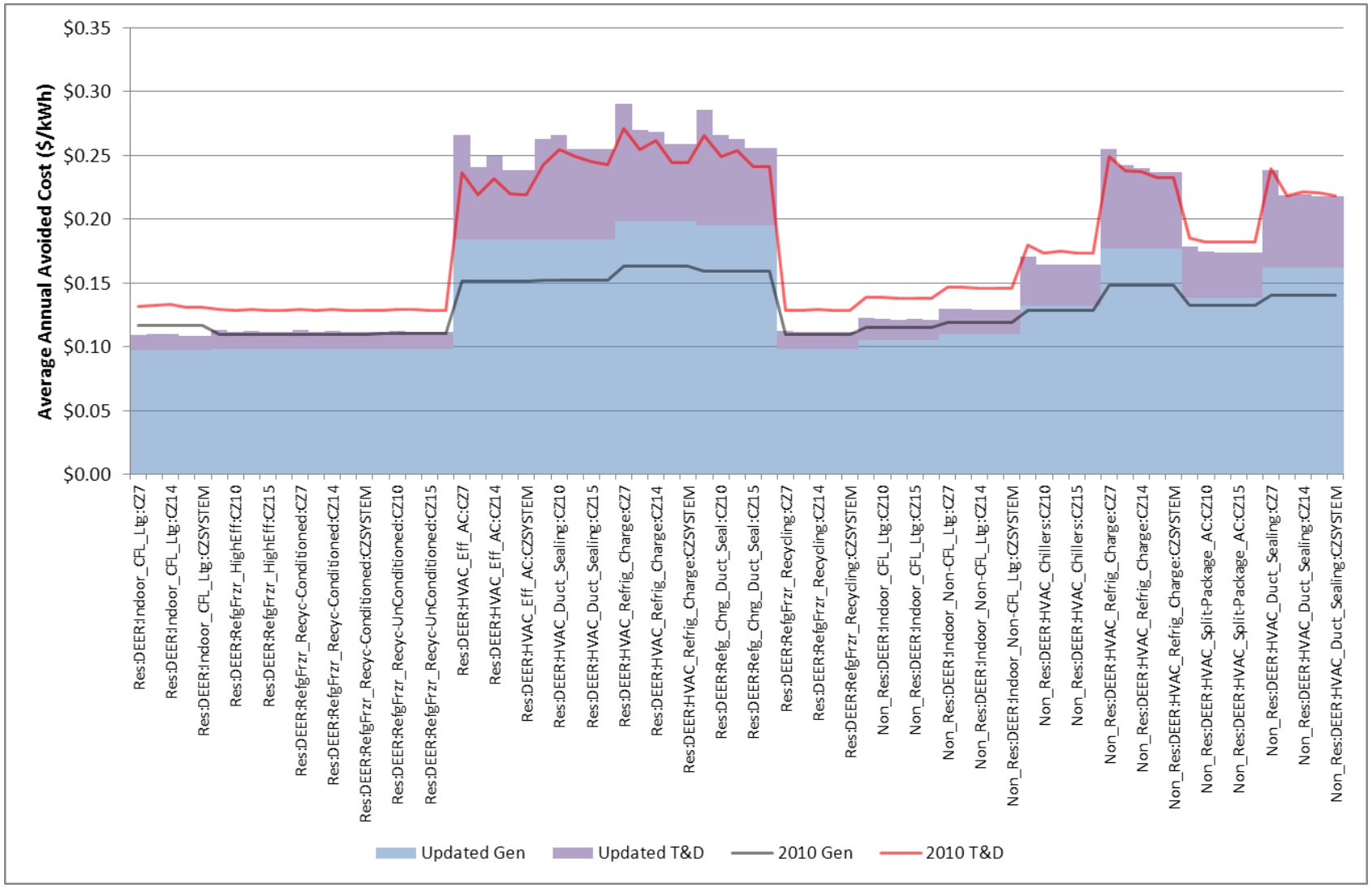
Non_Res:DEER:HVAC_Chillers:CZ10
Non_Res:DEER:HVAC_Chillers:CZ15
Non_Res:DEER:HVAC_Refrig_Charge:CZ6
Non_Res:DEER:HVAC_Refrig_Charge:CZ10
Non_Res:DEER:HVAC_Refrig_Charge:CZ15
Non_Res:DEER:HVAC_Split-Package_AC:CZ6
Non_Res:DEER:HVAC_Split-Package_AC:CZ10
Non_Res:DEER:HVAC_Split-Package_AC:CZ15
Non_Res:DEER:HVAC_Duct_Sealing:CZ6
Non_Res:DEER:HVAC_Duct_Sealing:CZ10
Non_Res:DEER:HVAC_Duct_Sealing:CZ15
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_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
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Res:DEER:RefgFrzr_Recycling:CZ7
Res:DEER:RefgFrzr_Recycling:CZ14
Res:DEER:RefgFrzr_Recycling:CZSYSTEM
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Non_Res:DEER:Indoor_CFL_Ltg:CZ15
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Non_Res:DEER:Indoor_Non-CFL_Ltg:CZ14
Non_Res:DEER:Indoor_Non-CFL_Ltg:CZSYSTEM
Non_Res:DEER:HVAC_Chillers:CZ10
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Non_Res:DEER:HVAC_Refrig_Charge:CZ7
Non_Res:DEER:HVAC_Refrig_Charge:CZ14
Non_Res:DEER:HVAC_Refrig_Charge:CZSYSTEM
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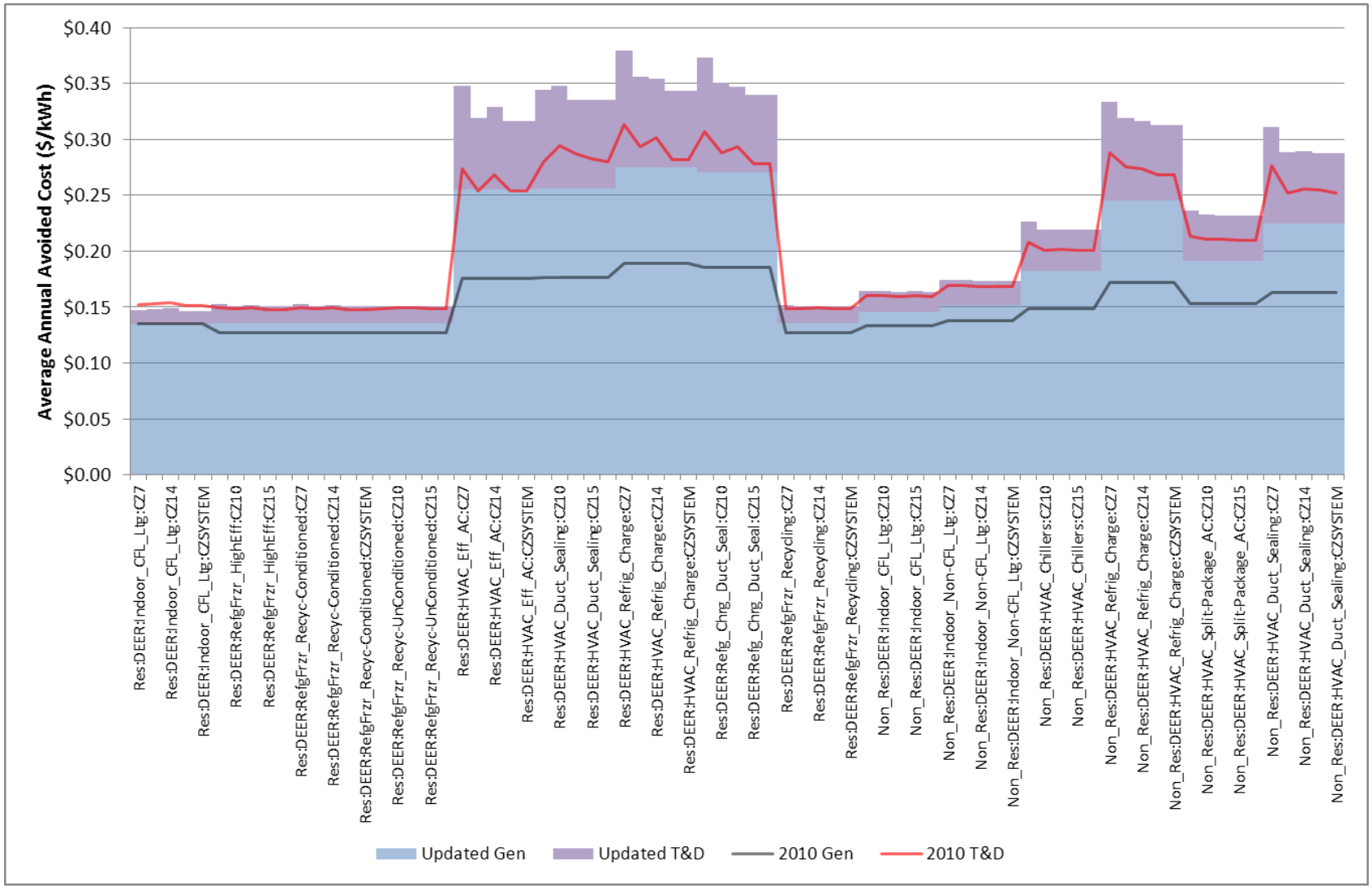
Non_Res:DEER:HVAC_Split-Package_AC:CZ15
Non_Res:DEER:HVAC_Duct_Sealing:CZ7
Non_Res:DEER:HVAC_Duct_Sealing:CZ14
Non_Res:DEER:HVAC_Duct_Sealing:CZSYSTEM
Updated Gen
Updated T&D
2010 Gen
2010 T&D

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.

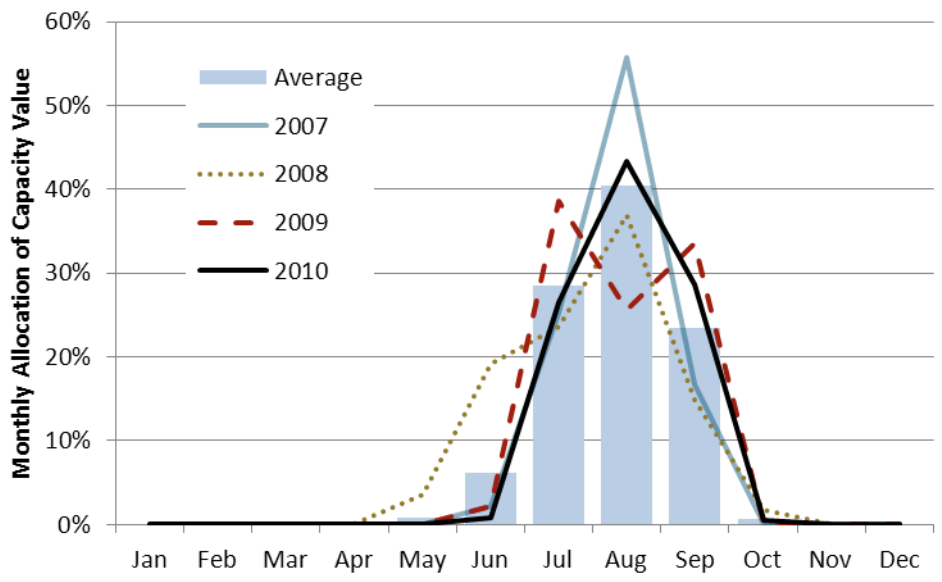


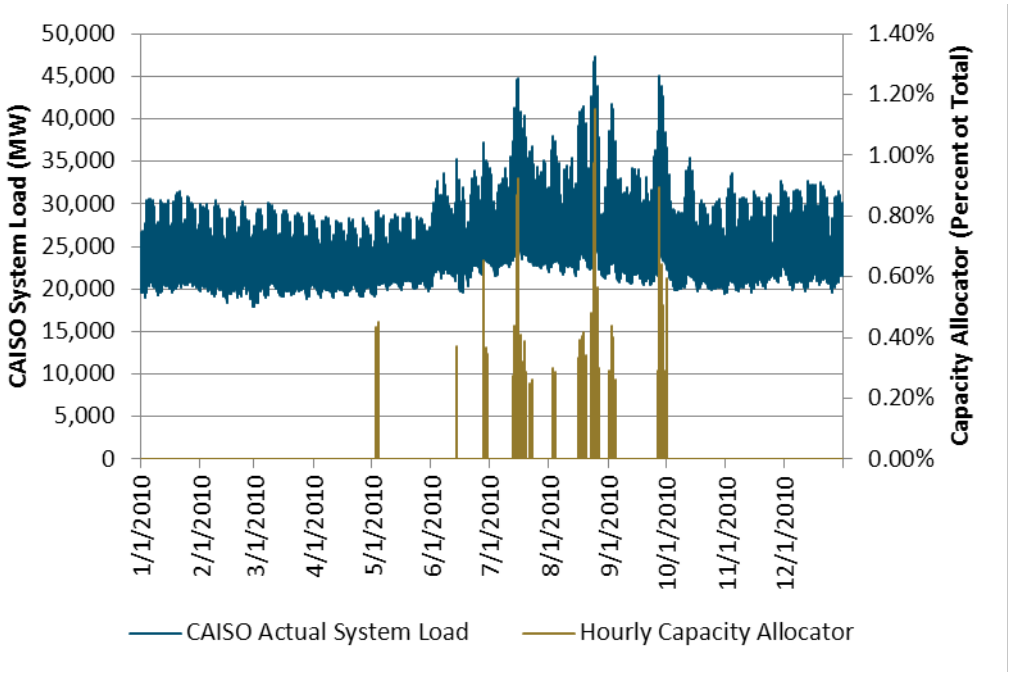
Table 8. Summary of monthly capacity allocation based on historical load data from 2007-2010.

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.

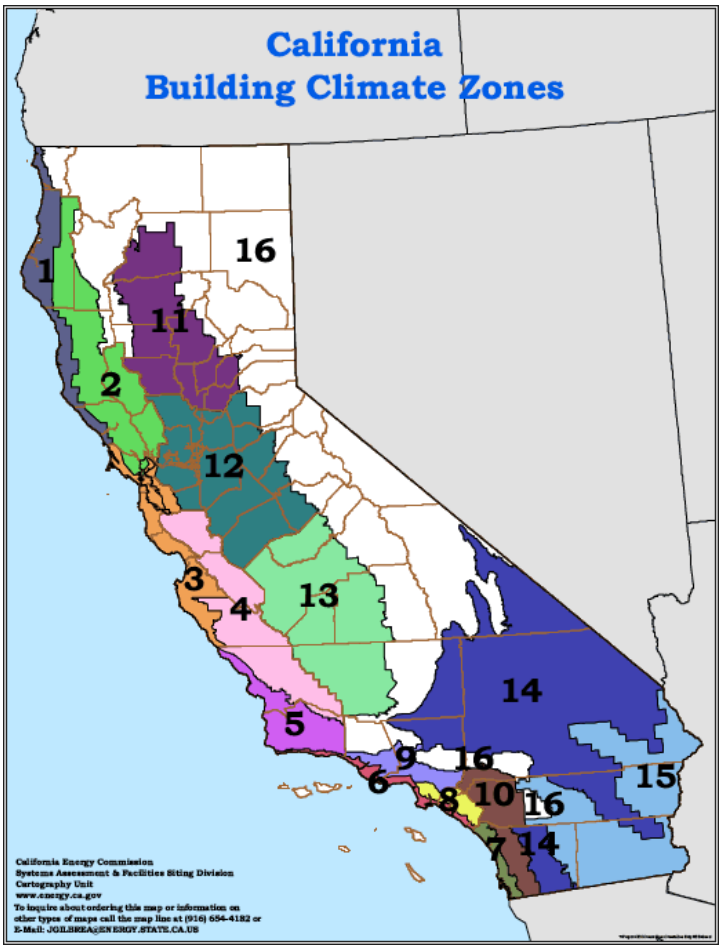
Table 10. Marginal energy loss factors by time-of-use period and utility.

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