Time Dependent Valuation of Energy for Developing Building Efficiency Standards

2016 Time Dependent Valuation (TDV) Data Sources and Inputs

July 2014

Energy+Environmental Economics

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California Energy Commission

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Contents Overview

This report describes data sources, calculations and results used in the 2016 Time Dependent Valuation (TDV) update for the Title 24 building standards. It reflects the TDV values included in the excel file named "TDV_2016 _Mid_20140707.xls"

Acknowledgements

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1 Background and Changes in 2016 TDV Inputs & Methodology

1.1 Principals and Purpose of TDVs

The Title 24 building standards are developed based upon the cost-effectiveness of energy efficiency measures in new buildings in California. The standards promote measures that have a positive benefit-cost ratio from a modified participant cost perspective. The Title 24 standards allow building designers to make trade-offs between energy saving measures using building simulation tools that evaluate the energy performance of proposed building designs.

Beginning with the 2005 standards update, time-dependent valuation (TDV) has been used in the cost-effectiveness calculation for Title 24. The concept behind TDV is that energy efficiency measure savings should be valued differently depending on which hours of the year the savings occur, to better reflect the actual costs of energy to consumers, to the utility system, and to society. The TDV method encourages building designers to design buildings that perform better during periods of high energy cost. Prior to 2005, the value of energy efficiency measure savings had been calculated on the basis of a "flat" source energy cost. In the 2016 TDV update, the hourly TDV factors are also correlated with the statewide typical weather files used in building simulation tools. This is important because in California hotter weather tends to be correlated with increased demand on the electrical system, increasing the cost of energy during those hours.

This report has been developed to document the methodology used to compute the 2016 TDV factors used in Title 24. The basic concepts and approach used to develop the TDV methodology are the following:

1. **Rational and Repeatable Methods**

   We have used published and public data sources for the fundamental analysis approach to developing TDV data. This allows revisions of the Standards and their underlying TDV data to be readily updated when called for by the California Energy Commission (CEC).

2. **Based on Hourly (or Monthly) Cost of Energy, Scaled to Retail Rate Levels** TDV is based on a series of annual hourly values for electricity cost (and monthly costs for natural gas and propane) in the typical CEC weather year. TDV values are developed for each of the sixteen climate zones, for residential and for nonresidential buildings. We have not used retail rates to value energy savings directly because rates are based on averages over time periods rather than hourly differences in the cost of generation. However, the hourly TDV values have been adjusted to be equivalent to a residential and nonresidential statewide average retail rate forecast.

3. **Seamless Integration within Title 24 Compliance Methods**

   The mechanics of TDV should be transparent to the user community and compliance methods should remain familiar and easy. TDV factors are represented in kWh/Btu or therms/Btu units, consistent with the previously used source energy approach and the 2008 and 2013 TDV updates.

4. **Climate Zone Sensitive**

   As with the weather data used for Title 24 performance calculations, which allow building designs to be climate responsive, the TDV methodology also reflects differences in costs driven by climate conditions. For example, an extreme, hot climate zone has higher, more concentrated peak energy costs than a milder, less variable climate zone.

5. **Components of TDV**

   The TDV method develops each hour's (or month's) energy valuation using a bottom-up approach. We sum together the individual components of the cost of energy and then scale up the values such that over the course of the year the values are equal the average retail price for residential and non-residential customers. The resulting electricity TDV factors vary by hour of day, day of week, and time of year. The key components of the electricity TDV factors are summarized below:

   - Marginal Cost of Electricity – *variable by hour* – The shape of the hourly marginal cost of generation is developed using the Commission's PLEXOS production simulation dispatch model (developed by Energy Exemplar). The price shape from the production simulation model is then adjusted to reflect the natural gas price forecast as well as the following non-energy costs of energy: transmission & distribution costs, emissions costs, ancillary services and peak capacity costs.

- Revenue neutrality adjustment – *fixed cost per hour* – The remaining, fixed components of total annual utility costs that go into retail rates (taxes, metering, billing costs, etc.) are then calculated and spread out over all hours of the year. The result, when added to the hourly marginal cost of electricity, is an annual total electricity cost valuation that corresponds to the total electricity revenue requirement of the utilities.

While the details of the Title 24 TDV methodology can be complex, at root the concept of TDV is quite simple. It holds the total cost of energy constant at forecasted retail price levels but gives more weight to on-peak hours and less weight to off-peak hours. This means that energy efficiency measures that perform better on-peak will be valued more highly than measures that do not.

1.2 Overview of Key Assumptions

The economics for the 2016 Title 24 Building Energy Efficiency Standard TDVs, like those developed for the 2008 and 2016 T24 updates, are based on long-term (15- and 30-year) forecasts that reflect existing energy trends and state policies. The timeframe of the economic analysis used in the 2016 TDVs spans the years 2017 to 2046 for the 30-year analysis and 2017 to 2031 for the 15-year analysis. TDV NPV costs are reported in 2016 dollars, and are formatted to the 2009 calendar year and 2009 weather year file data.

The majority of the input assumptions for the 2016 TDV Update are taken from the 2013 Integrated Energy Policy Report (2013 IEPR) and associated planning documents. To reflect current state policy, the 2016 Title 24 TDV factors include the costs and generation impacts of the Renewable Electricity Standard (requiring 33% renewables by 2020) as well as other policies around the state law (AB 32) which requires a reduction in greenhouse gas (GHG) emissions to 1990 levels by 2020. The table below describes the key assumptions included in the 2016 TDV numbers.

Table 1. Key Assumptions in 2016 TDVs

Input	Description
Overview:	***TDVs reflect current state policy and energy trends.***
Retail rate escalation	
CO_2 price	2013 IEPR Mid Case, based on current Cap-and-Trade and Trade regulation continuing through 2020. Assumes a high probability that complementary policies reduce emissions through 2017, but that the availability of complementary policies diminishes after 2017.[1]
Renewable Portfolio Standard (RPS)	Assume California meets a 33% RPS by 2020. Renewable portfolio is based on 2012 Long-term Procurement Planning (LTPP) "Commercial" Scenario for R. 12-03-014. [2]
Energy Efficiency	2012 California Energy Demand Forecast - Mid Demand case, including Additional Achievable Energy Efficiency Mid Case.[3]

1.3 Key Changes in the 2016 TDVs Compared to the 2016 Methodology

This section summarizes the key changes to the 2016 TDV methodology compared to the 2013 approach. Overall, the 2016 methodology represents refinements and improvements to the 2016 methodology but does not include any major departures from the prior approach.

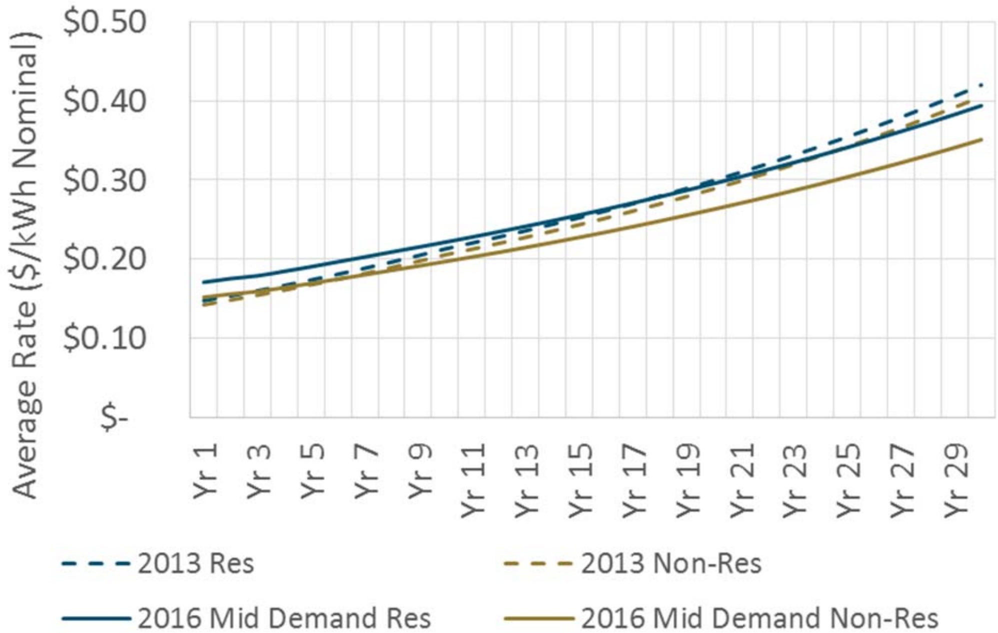
1.3.1 2013 IEPR RATE FORECAST

The 2016 TDVs incorporate the average electricity rate forecasts from the 2013 IEPR. Compared to the rate forecast used for the 2013 TDVs, the new electricity rate forecast begins higher in the early years, but

[1] Based on analysis presented in a report" Forecasting Supply and Demand Balances in California's Greenhouse Gas Cap-and-Trade Market" March 12, 2013. This reported was prepared by members of the Emissions Market Assessment Committee and the Market Simulation Group. The mid case scenario increase in price of 1.5 times the low energy consumption scenario is based on the Economic Analysis done in support of the regulations to implement the California Cap-and-Trade program. Appendix N, page N-13.
[2] See December 19, 2012 Joint California Energy Commission and California Public Utilities Commission staff Workshop on renewable resource portfolios for the California ISO Transmission Planning Process.
[3] California Energy Demand 2012-2022 Final Forecast. May 2012. CEC-200-2012-001-SF-VI

escalates at a lower rate than the 2013 values. The 2013 forecast escalated at 3.4%/yr. in nominal terms after 2020, compared to 2.9%/yr. for the 2016 forecast.

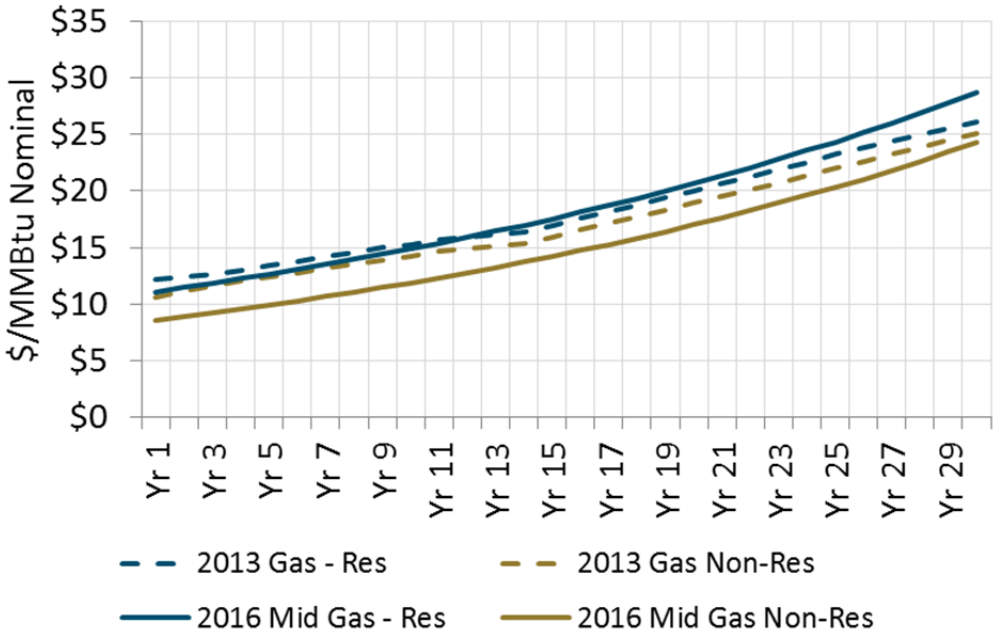
Figure 1. Comparison of electricity retail rate forecasts in the 2013 and 2016 TDVs.[4]



The natural gas retail rate forecast has been updated using the 2013 IEPR rate forecast for residential and commercial end users (2013 IEPR Table 14). Like the electricity rate forecast, the updated 2016 forecast is comparable overall to the extant values. Although in the case of natural gas, the updated forecast starts lower than the extant forecast, but escalates at a higher rate per year.

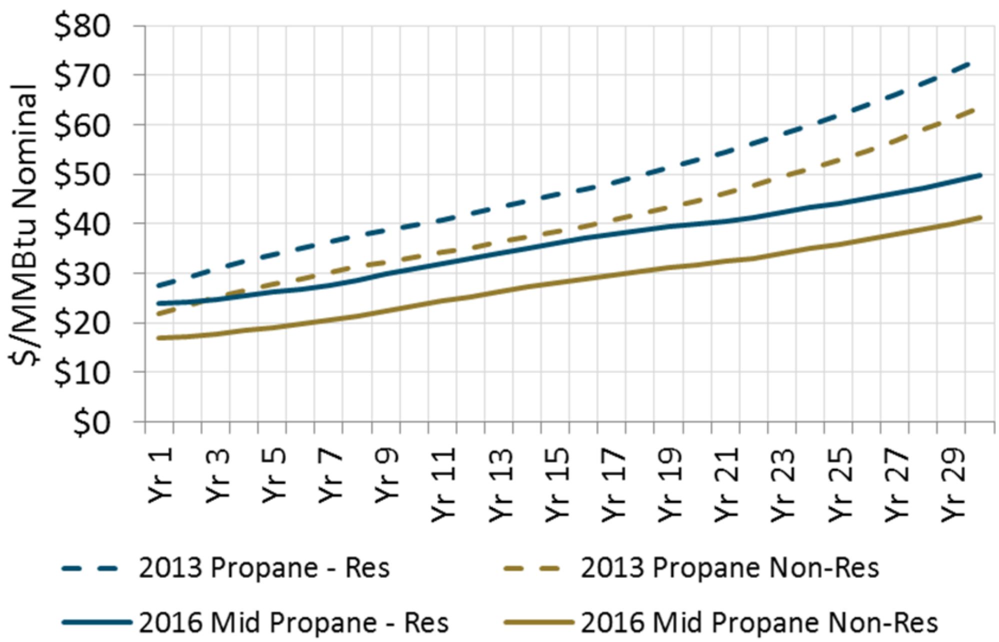
[4] All annual forecasts shown in this report are expressed in nominal dollars.

Figure 2. Comparison of gas retail rate forecasts in the 2013 and 2016 TDVs.



The updated propane forecast shows an overall lowering in forecast retail prices compared to 2013. The propane forecast is based on the US Energy Information Agency Annual Energy Outlook 2013 for the Pacific Region, calibrated to match the natural gas price forecast from the IEPR. The EIA AEO report shows a narrowing in the price differential between propane prices and natural gas end user rates, which drives the lower propane forecast.

Figure 3. Comparison of propane retail price forecasts in the 2013 and 2016 TDVs.



1.3.2 2013 IEPR PLEXOS PRODUCTION SIMULATION PRICES

The avoided cost of energy reflects the marginal cost of generation needed to meet load in each hour. For the 2013 TDVs, the wholesale value of energy through 2014 was based on market forwards for Northern and Southern California (NP15 and SP15). The long-run value of energy was calculated based on the assumption that the average market heat rate will remain stable; the implied market heat rate based on 2014 forwards is extended through 2040. The long-run value of energy was calculated by multiplying the gas price forecast by this market heat rate. The hourly shape for wholesale energy prices is developed using the California Energy Commission production simulation dispatch model runs using 2012 and 2020 test years.

The CEC performed more extensive production simulation modeling for the 2013 IEPR than was available for the prior TDV update. The 2016 TDV update uses the "Mid-Demand" production simulation cases developed for the eight year period from 2017-2024 in the 2013 IEPR Proceeding. As with the 2013 TDVs, the production simulation cases are re-run with load shapes that are correlated to the TMY weather files. The inputs to the CEC production simulation model are described further in Section 4.2.

1.3.3 EFFECTIVE LOAD CARRYING CAPACITY (ELCC)

E3 has updated the avoided cost methodology to utilize effective load carrying capability (ELCC) when calculating the capacity value for renewable or thermal generators.[5] The methodology change was made pursuant with Senate Bill (SB) 2 (Simitian, Kehoe, and Steinberg, 2011)[6] due to a general recognition that ELCC is a more appropriate measure of capacity value under quickly changing, high Renewable Portfolio Standard (RPS) scenarios. ELCC is a dynamic assessment of renewable capacity value and captures the relationship between renewable penetration and contribution to system reliability. As penetrations of wind or solar increase, the load carried by additional resources of the same type is reduced due to a gradual shift in the net load peak towards hours during which the resource has lower capacity factors. ELCC values were developed for 2013 (current) and 2020 (33% RPS) conditions; values for 2017 through 2019 are interpolated.

The prior method allocates capacity value fairly broadly between hour ending (HE) 12 through HE 21 predominately in the months of July, August and September (Figure 4). The updated ELCC based approach allocates capacity value more narrowly between HE 13 and HE 18 in 2013 (Figure 5). By 2020, with the increase in solar generation, the allocation of capacity value shifts predominately to peak net load hours HE 18 & 19 in September. The double peak shown for September is the result of averaging hourly values for the month. On cloudy days, lower solar generation results in peak net loads around HE 15 & 16. On sunny days with high solar generation, peak net loads occur later in the evening.

[5] ELCC is the additional load met by an incremental generator while maintaining the same level of system reliability

[6] See http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html

Figure 4: Capacity Allocators Based on the Old Capacity Allocation Methodology

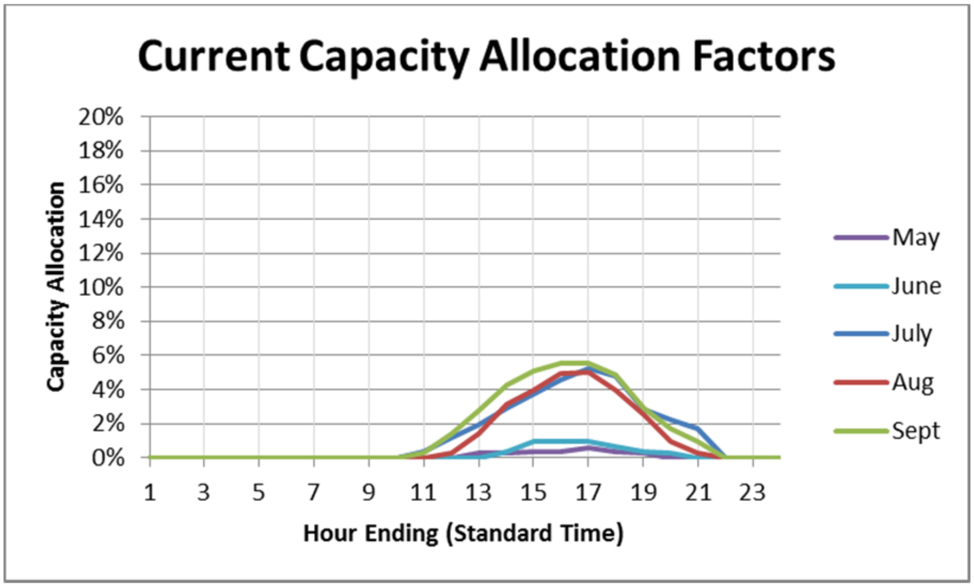


Figure 5: 2013 Capacity Allocation by Time of Day using ELCC

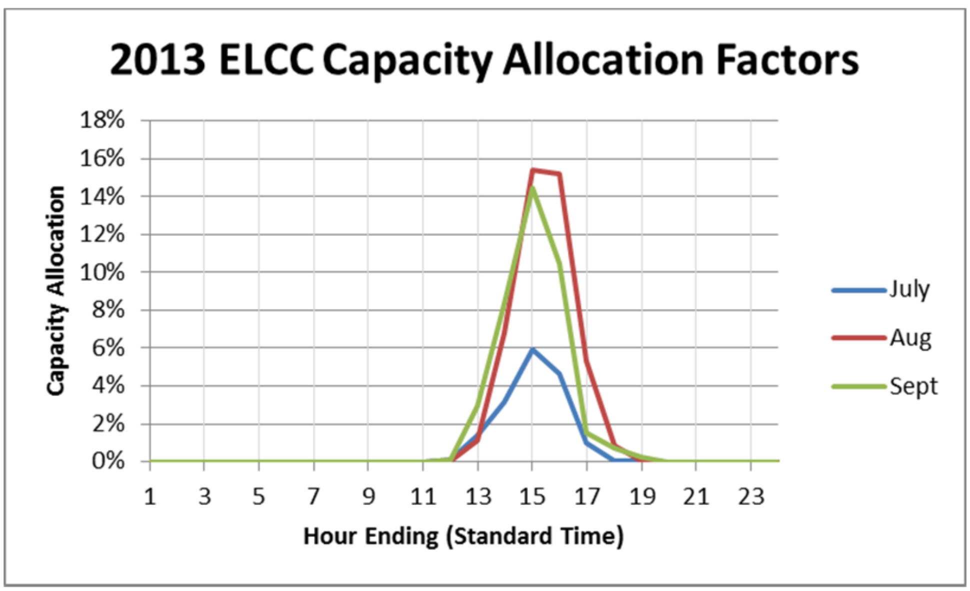
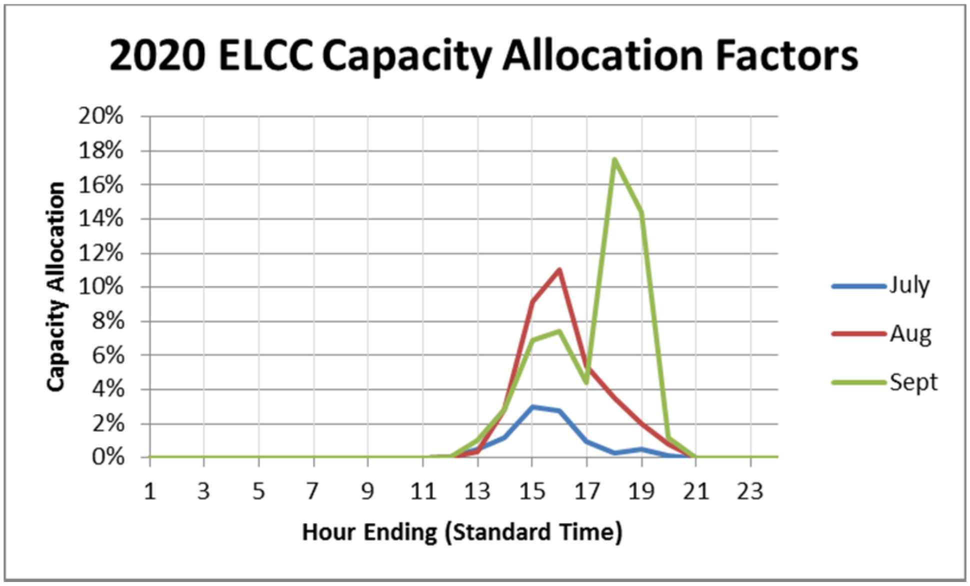


Figure 6: 2020 Capacity Allocation by Time of Day using ELCC



1.3.4 RPS ADDER

In 2016 we included the RPS adder as a separate component for the TDV calculations. This change has no impact on the TDV results – it is merely an accounting convention to make the CEC TDV and CPUC avoided cost values more directly comparable. In prior years, the impact of RPS requirements was included in the retail rate adder.

The RPS adder represents the benefit that electricity usage reduction has in reducing renewable purchases. Because of California's commitment to reach a RPS portfolio of 33% of total retail sales by 2020, any reductions to total retail sales will result in an additional benefit by reducing the required procurement of renewable energy to achieve RPS compliance. This benefit is captured in the avoided costs through the RPS Adder.

The RPS Adder captures the value that a reduction in load brings to ratepayers through a reduction in required procurement to comply with the state's Renewable Portfolio Standard. Because the state's current RPS policy requires each utility procure renewable generation equivalent to 33% of its retail sales in 2020, each 1 MWh reduction in load in 2020 reduces a utility's compliance obligation by 0.33 MWh. This reduction in a utility's compliance obligation translates directly to a ratepayer benefit through a reduction in the above-market cost of resources used to serve load. The calculation of the RPS adder is described in Section 4.3.8.

2 Approach

2.1 Overview of Avoided Cost of Electricity

The TDV values reflect the hourly or monthly 'shape' of the total costs of the three fuels affected by the Title 24 standards; electricity, natural gas, and propane, including wholesale market costs, delivery, and emissions costs. In each case the underlying shape of the marginal cost is adjusted with a flat adder to the 'level' of forecasted retail rates.

For each climate zone, the avoided cost is calculated as the sum of seven components, each of which is summarized in Table 2.

Table 2. Components of marginal energy cost

Component	Description
Generation Energy	Estimate of hourly marginal wholesale value of energy adjusted for losses between the point of the wholesale transaction and the point of delivery
System Capacity	The marginal cost of procuring Resource Adequacy resources in the near term. In the longer term, the additional payments (above energy and ancillary service market revenues) that a generation owner would require to build new generation capacity to meet system peak loads
Ancillary Services	The marginal cost of providing system operations and reserves for electricity grid reliability
T&D Capacity	The costs of expanding transmission and distribution capacity to meet customer peak loads
CO2 Emissions	The cost of carbon dioxide emissions (CO2) associated with the marginal generating resource
Avoided RPS	The cost reductions from being able to procure a lesser amount of renewable resources while meeting the Renewable Portfolio Standard (percentage of retail electricity usage).

In the value calculation, each of these components is estimated for each hour in a typical year and forecasted into the future for 30 years. The hourly granularity of the avoided costs is obtained from several sources. The wholesale price of electricity shape is obtained from two production simulation dispatch model runs. Other components of the value calculation are derived by shaping forecasts of the average value of each component with historical day-ahead and real-time energy prices reported by the

California Independent System Operator (CAISO's MRTU system). Table 3 summarizes the methodology applied to each component to develop the hourly price shapes.

Table 3. Summary of methodology for avoided cost component forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	IEPR Production Simulation Results for 2017-2022, escalated based on gas price forecasts thereafter.	IEPR Production Simulation Results
System Capacity	Fixed costs of a new simple-cycle combustion turbine, less net revenue from energy and AS markets	Effective Load Carrying Capacity
Ancillary Services	Scales with the value of energy	Directly linked with energy shape
T&D Capacity	Survey of investor owned utility transmission and distribution deferral values from recent general rate cases	Hourly allocation factors calculated using hourly temperature data
Greenhouse Gas Emissions	2013 IEPR	Directly linked with energy shape based on implied heat rate of marginal generation, with bounds on the maximum and minimum hourly value
RPS Adder	Premium for renewable generation calculated in E3 DER Avoided Cost Model.	Constant allocation factor, does not vary by hour
Retail Rates	2013 IEPR	Constant allocation factor, does not vary by hour

The hourly time scale used in this approach is an important feature of the TDVs. Figure 7, below, shows the 30 year levelized TDVs for Climate Zone 12, averaged over the 24 hours of the day and broken out by component. The double peak in HE 13 and HE 16 is the result of the ELCC based capacity allocation changing over time and the averaging of low and high solar generation days. Figure 8 shows the levelized values on an 8,760 hourly basis, illustrating the concentration of generation and T&D capacity value in select hours. Whereas the peak values TDV values for the 2013 update were just over $1,600, the ELCC approach results in a more concentrated allocation of capacity value, with peak TDVs over $3,000/MWh.

Figure 7. 30 Year Levelized TDV (Climate Zone 12)

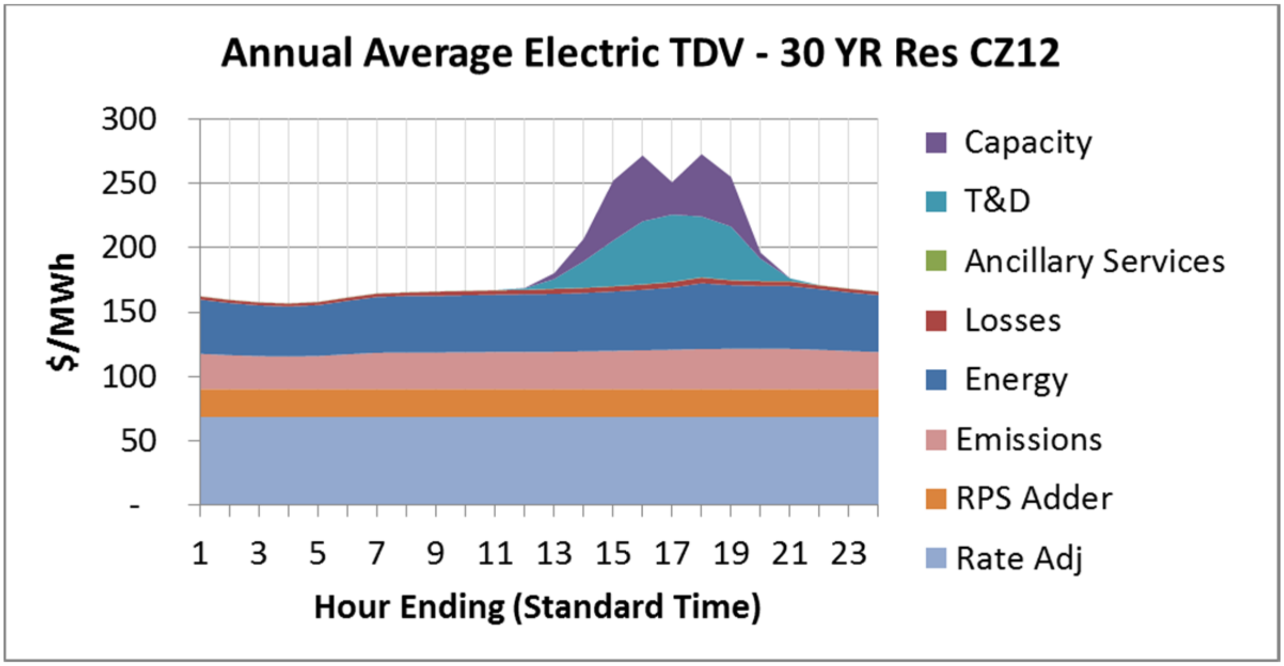
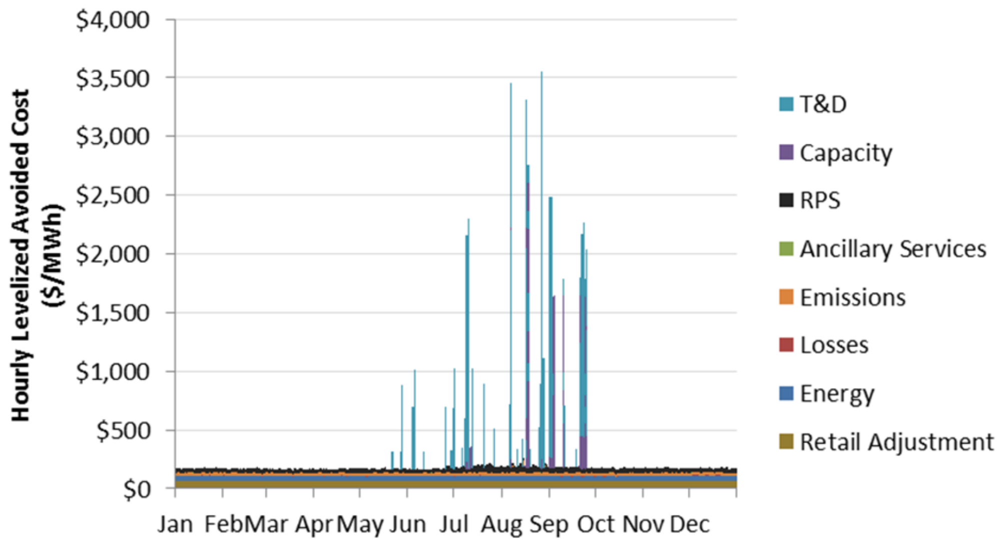


Figure 8 shows the annual chronological set of estimated values for Climate Zone 2 for an entire year. There are several hundred high hourly spikes driven by hours with the highest loads. The spikes are caused by the costs of adding capacity to deliver electricity in the few highest load hours. For the rest of the hours, the value of energy in the wholesale market is the primary component; it fluctuates by time of day and by season to reflect the trends of California's wholesale markets.

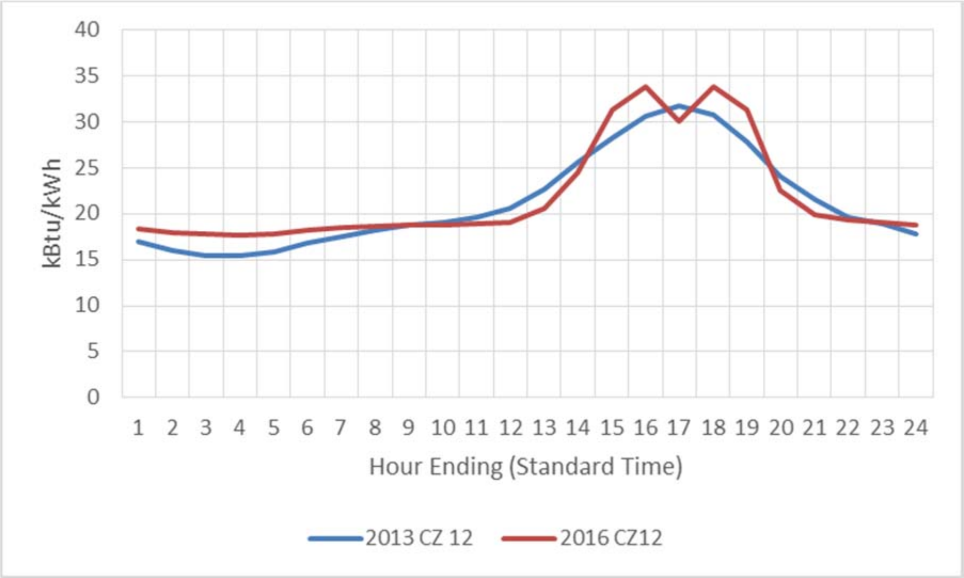
Figure 8. Hourly levelized TDVs (CZ 12)



2.2 Results

The resulting levelized electricity 2016 TDV factors are compared to the 2013 TDVs in Figure 9. The calculation of the levelized kBtu/kWh factors and the source of the double peak in the 2016 TDVs are discussed further below.

Figure 9. Resulting 30 Year Levelized TDV Factors (CZ 12)



3 Calculating Net Present Value TDVs

The Warren-Alquist Act, requires the Energy Commission to develop and maintain energy efficiency standards that are "*… cost effective, when taken in their entirety, and when amortized over the economic life of the structure when compared with historic practice*".[7] This section describes the life-cycle cost (LCC) methodology to be used to evaluate proposed changes for the 2016 Building Energy Efficiency Standards. Cost effectiveness analysis is needed only for mandatory measures and prescriptive requirements. It is not required for compliance options.

The 2016 TDV development process is largely the same as the approach taken for 2013, but updated with more current projections of energy costs. To calculate the "lifecycle" value of energy savings, we calculate the net present value (NPV) of each hour's energy cost over a 15-year and 30-year nonresidential analysis period and over a 30-year residential analysis period. The NPV is calculated by applying a 3% real (inflation adjusted) discount rate, inflation is assumed to be 2% per year. Next, the NPV TDV is converted from a cost per unit energy ($/kWh) to an energy only unit (kWh/Btu). The TDV values are presented in terms of energy units for the following reasons:

+ Describing TDV in terms of energy units is consistent with past performance method compliance methods. The intent is to minimize the impact of TDV on practitioners; TDV energy units are simply substituted for source energy, which was the original unit of analysis.
+ Converting the TDV cost units to energy units makes it less likely that someone might mistakenly interpret TDV savings as an estimate of the dollar savings that an individual building owner might see by implementing the Tile 24 standard. Given that local utility rates vary over time and across regions, and given that actual building operating practices can vary significantly, it was not desirable to imply that the TDV savings are the same as the dollar savings that any single building owner might realize.

[7] Warren Alquist Act, Public Resources Code Section 25402.

TDVs are converted to energy units using the same NPV cost in real dollars of natural gas as was applied in the 2005 and 2013 standards. By using the same conversion factor (in real dollars) in each Title 24 update, the relative stringency of the TDVs can be more easily compared across periods. This is appropriate because the adjustment factors are merely an accounting convention and the underlying TDVs already reflect updates for energy prices, inflation etc. An increase in natural gas price forecasts between updates would, as expected, result in an increase in the TDVs. However, note that in the adjustment factor formula below that $/kBtu natural gas prices are in the denominator. Thus reflecting an *increase* in natural gas prices would result in a *decrease* in the adjustment factor- effectively negating the expected impact on $/kBtu TDV.

The nonresidential 15-year conversion factor (based on the 2005 forecasted NPV gas cost) is $0.089/kBtu expressed in 2017 dollars. The residential conversion factor (based on the 2005 forecasted NPV gas cost) is $0.173/kBtu in 2017 dollars.

For evaluating the cost-effectiveness of new measures, the annual TDV energy savings can be multiplied by the following standardized factors, shown in the table below in NPV $/kBtu in 2017 dollars.

Table 4. TDV Conversion Factors, NPV 2017$/kBtu

	NPV (30-year)	NPV (15-year)
Low-Rise Residential	$0.1732	n.a.
Nonresidential & High-rise Residential	$0.1540	$0.0890

The equation below, by example, provides the units analysis for electricity TDV to move from the $/kWh to TDV kBtu/kWh. The "TDV energy factors" are the source energy values referenced in the Title 24 regulations and used in the compliance calculation process to produce a TDV kBtu energy use estimate for a modeled building:

$$\text{TDV Energy Factors} = \frac{\text{TDV Dollars}\left[\text{NPV\$/kWh}\right]}{\text{Forecasted NG Cost}\left[\text{NPV\$/kBtu}\right]} = \frac{\dfrac{\text{NPV\$(hr)}}{\text{kWh}}}{\dfrac{\text{NPV\$}}{\text{kBtu}}} = \frac{\text{kBtu(hr)}}{\text{kWh}} \; or \; \frac{\text{TDV kBtu}}{\text{kWh}}$$

Just like TDV dollar values, the TDV energy factors vary for each hour of the year. To evaluate the TDV energy cost or benefit of a measure, each hour's electricity savings is multiplied by that hour's TDV energy value. As shown below, this yields an annual savings figure in terms of TDV kBtu.

$$\text{Annual TDV Savings}\left[\text{TDV kBtu}\right] = \sum_{h=1}^{8,760} \text{Energy Savings}_h \left[\text{kWh}\right] \times \text{TDV Energy Factor}_h \left[\frac{\text{TDV kBtu}}{\text{kWh}}\right]$$

For evaluating the cost-effectiveness of new measures, the annual TDV kBtu energy savings calculated by an energy model can be multiplied by the $/kBtu adjustment factors listed in Table 4.

The resulting average TDV values (unweighted) across all climate zones and hours of the year are shown in Table 5 for the 2008, 2013 and 2016 TDV Update cycles. The statewide average TDV's have declined for non-residential buildings, reflecting the lower rate forecast relative to 2013 (Figure 1). The residential TDVs have increased, reflecting the slightly higher rate forecast relative to 2013.

Table 5. Statewide average TDV factors for Natural Gas and Electricity, 2008 - 2016

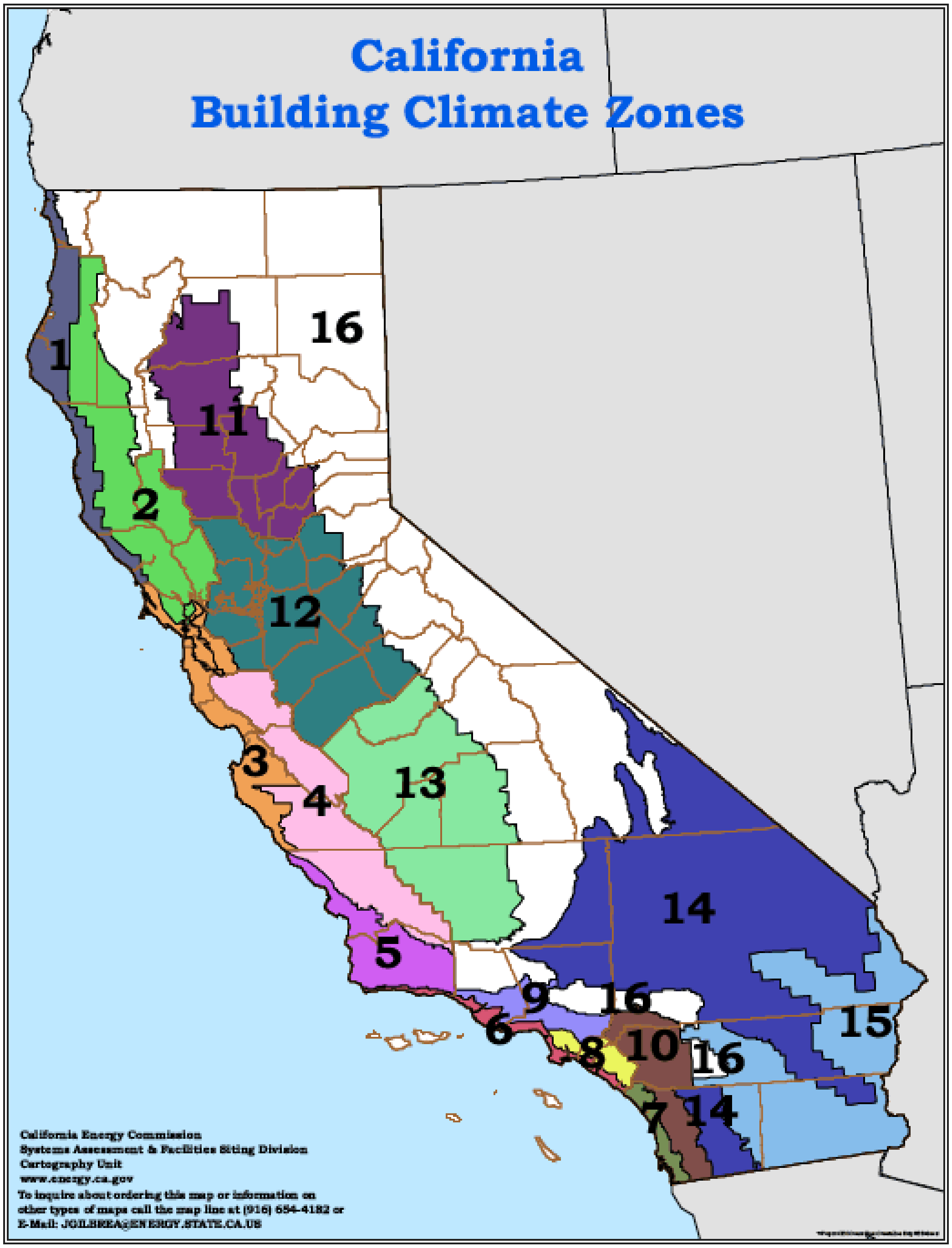
Time Period	2008	2013	2016
30 Year Residential			
Natural Gas (NPV$/Therm)	$24.32	$27.68	$28.64
Electricity (NPV $/kWh)	$2.33	$3.62	$3.73
15 Year Non-Residential			
Natural Gas (NPV$/Therm)	$12.72	$14.59	$12.75
Electricity (NPV $/kWh)	$1.63	$1.85	$1.83
30 Year Non-Residential			
Natural Gas (NPV$/Therm)	$23.97	$25.96	$23.62
Electricity (NPV $/kWh)	$2.66	$3.36	$3.19

4 Electricity Base TDVs: Data Sources and Methodology

4.1 Climate Zone Mapping

In each hour, the value of electricity delivered to the grid depends on the point of delivery. The Title 24 Standard uses sixteen California climate zones in order to differentiate the changing value of electricity across different regions in 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 10 is a map of the Title 24 climate zones in California.

Figure 10. 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 6, along with the IOU service territory that serves the majority of the load in each climate zone.

Table 6. Representative Cities for California Climate Zones

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

* Climate zone 7 uses SCE market price shape data.

Most of the components of avoided costs in the 2016 TDVs vary by climate zone but do not vary by IOU service territory. The two exceptions are for avoided line losses and the market price shapes developed in the CEC's production simulation dispatch model, which vary based on the IOU service providers specified in Table 6 (note that Climate Zone 7, though served by SDG&E, uses the SCE market price shape for consistency with the other Southern regions). All other components of the avoided cost of electricity are calculated using statewide average utility costs, including residential and nonresidential retail rates and avoided transmission and distribution costs. This represents a slight departure from the 2013 methodology, where IOU-specific utility costs were applied to most components of the avoided costs.

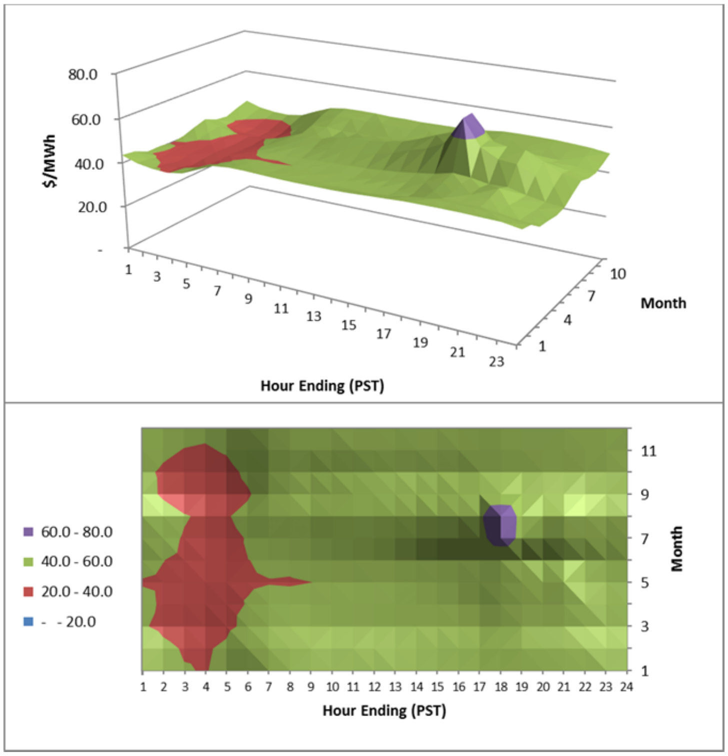
E3 moved to a more unified statewide average costing approach for two reasons. First, over a 15 or 30-year analysis period, current differences between IOU costs may change. Second, the TDVs are used by the Commission in the New Solar Homes Partnership (NSHP) program, which bases solar PV incentive levels in part on TDV factors. From a policy perspective, it was not desirable to have significantly different incentives being offered in neighboring climate zones due to differences in IOU utility costs, as was the case using the 2013 TDVs. By using statewide average costs in the 2016 TDVs, the large differences between the climate zones seen in 2013 have been reduced.

4.2 2013 IEPR Inputs Used for 2016 TDV Update

The avoided cost of energy reflects the marginal cost of generation needed to meet load in each hour. A change for the 2016 TDV Update is the use of eight years of production simulation modeling for 2017-2024 developed for the 2013 IEPR (in place of the 2012 and 2020 base years used for the 2013 TDV Update).

The production simulation generates 8,760 hourly electricity prices for 2017-2024. Beyond 2024, electricity prices are escalated with the annual increase in the 2013 IEPR natural gas price forecast. The inputs used in the production simulation modeling are described in this section. The resulting average energy component is shown in Figure 11.

Figure 11: Average Energy Component (CZ 12)



4.2.1 CORRELATING LOAD AND WEATHER

Consistent with the approach used in the previous TDV update, the production simulation cases are re-run using load shapes that correlate the electricity market price shapes with the 2013 statewide typical meteorological year (TMY) files. This means that the hottest days of the year in the TMY files will also reflect the highest TDV value hours of the year. Because the 2013 IEPR used the same load shapes, base year and TMY files that were used for the 2013 TDV Update, no updates were required for this step.

The production simulation model does not use temperature or weather as an input; rather, the model uses annual hourly electricity load profiles by region as inputs. Since electricity demand is highly correlated with temperature in California, we used set of annual hourly load profiles for each of the 18 California regions in the simulation model. For the 2013 TDV Update, E3 used statistical analysis to capture the historical relationship between temperature and electricity demand in each region and regression techniques to forecast new load shapes that correspond to the Title 24 weather files that were developed for the Energy Commission by Whitebox Technologies. These results were used for the 2016 TDV Update as well.

The regression analysis used to develop weather-correlated load shapes accounts for:

+ Weather effect (dry bulb temperature, dew point temperature, cooling and heating degree hours & 3-day lagged cooling and heating degree days)
+ Time-of-use effect (hour, day, month, holidays)
+ Skew of load data (hourly distribution has long tail)
+ Peak loads (secondary regression captures peak hours for temps above 75˚F)
+ Load growth (data are normalized for peak load)

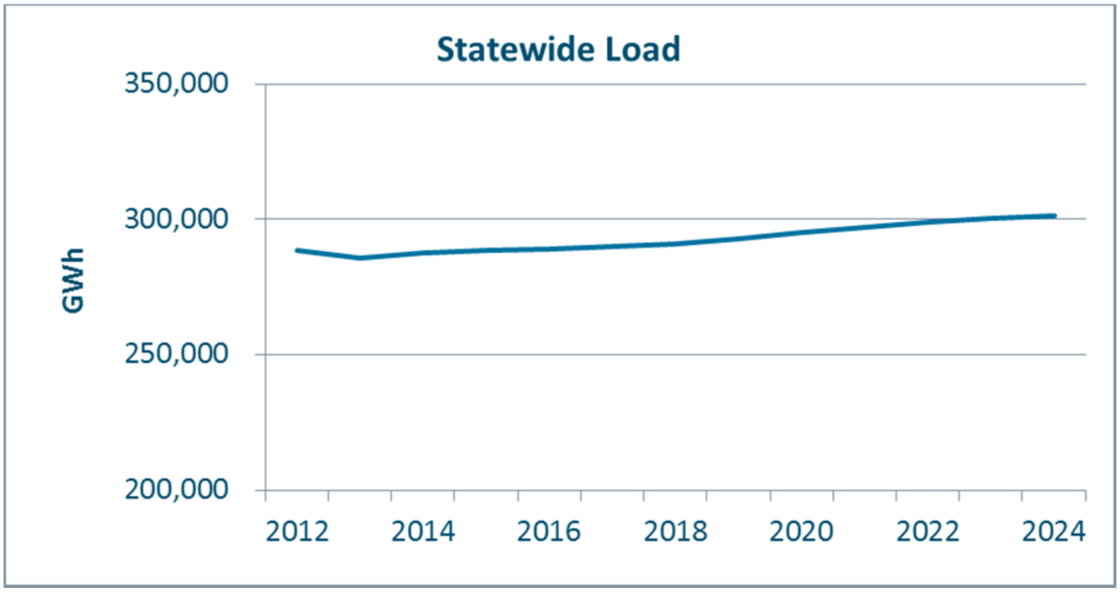
A more detailed description of the statistical approach employed to develop the weather-correlated load shapes is provided in Appendix A.

4.2.2 LOAD FORECAST

The 2013 IEPR adopted load forecast is based on the California Energy Demand 2014-2024 Final Forecast (2013 CED) (Figure 12).[8,9] The 2013 CED includes three full scenarios: a high energy demand case, a low energy demand case, and a mid energy demand case. The high energy demand case incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low efficiency program and self-generation impacts. The low energy demand case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self-generation impacts. The mid case uses input assumptions at levels between the high and low cases. Details on input assumptions for these scenarios are provided in Chapter 1 of the 2013 CED.

[8] The 2013 IEPR adopted forecast is available at http://www.energy.ca.gov/2013_energypolicy/documents/#adoptedforecast
[9] For the 2013 CED (CEC-200-2012-001-SF-VI, May 2012). See "Reports Not Associated with a Meeting" at http://www.energy.ca.gov/2012_energypolicy/documents/

Figure 12. 2013 IEPR Mid Demand Load Forecast



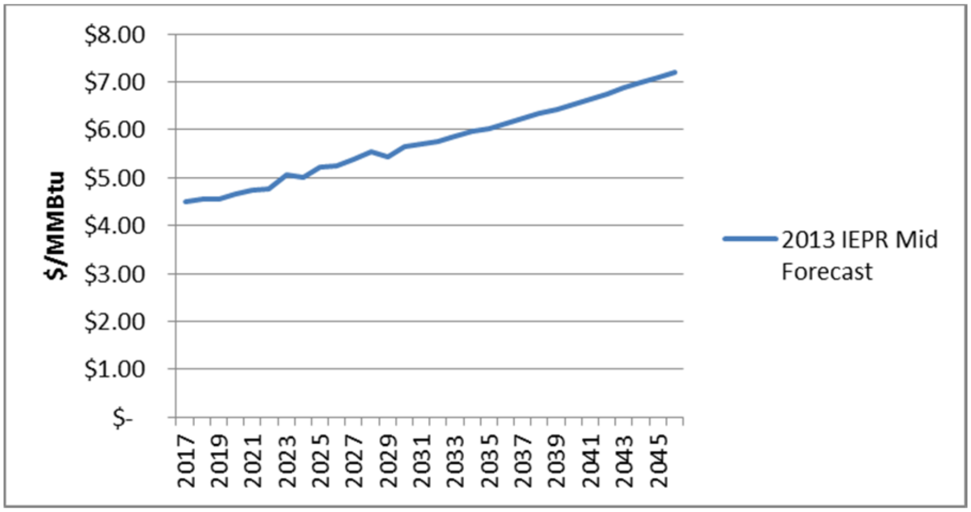
4.2.3 NATURAL GAS PRICE FORECAST

The 2013 IEPR adopted natural gas price forecast is the basis for the calculation of the electricity market prices (Figure 13). Natural gas burner tip prices represent the cost of gas for a natural gas-fired electric generator and include both a commodity and a transportation component. The commodity component is the price of the natural gas at a price hub (e.g. Henry Hub). The transportation component is the cost of transporting the gas from a given price hub or basin to the electric generator for consumption.

The method for estimating burner tip prices is based on forecasted annual natural gas commodity prices from the World Gas Trade Model and transportation rates from interstate, intrastate, and utility level transportation rates. The annual forecasted natural gas commodity prices are first converted to monthly values. Then, the appropriate transportation rate (tariff) is added to account for transportation to the electric generator. Further information can be found in "Estimating Burner Tip Prices, Uses, and Potential Uses" (CEC-200-2013-006, November 2013).[10]

[10] See at http://www.energy.ca.gov/2013publications/CEC-200-2013-006/CEC-200-2013-006.pdf

Figure 13. 2013 IEPR Natural Gas Price Forecast for Electric Generation in California

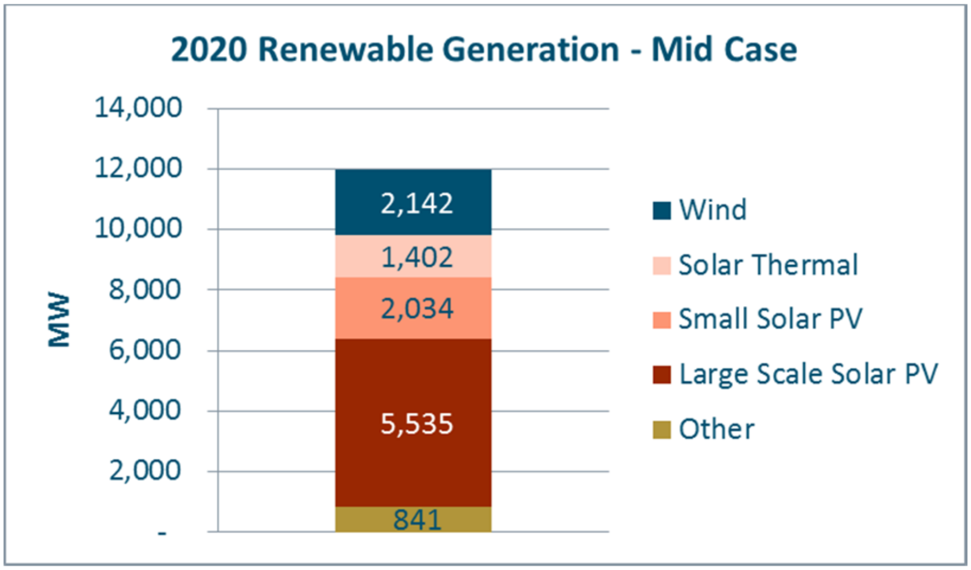


4.2.4 RENEWABLE GENERATION

The 2013 IEPR Mid Case assumes that California will meet the 33% RPS target in 2020. The portfolio of renewable resources (Figure 14) is based on 2012 Long-term Procurement Planning (LTPP) "Commercial" Scenario for R. 12-03-014.[11] The portfolio includes 5.5 MW of large scale solar PV, 2.0 MW of small solar PV, 1.4 MW of solar thermal, 2.1 MW of Wind. The 0.8 MW of "Other" includes biogas, biomass and geothermal. For 2020 through 2024, renewable generation increases with load, proportional with the portfolio shown below.

[11] See December 19, 2012 Joint California Energy Commission and California Public Utilities Commission staff Workshop on renewable resource portfolios for the California ISO Transmission Planning Process.

Figure 14. 2013 IEPR Mid Case Portfolio of Renewable Resources in 2020.



4.2.5 GHG PRICE FORECAST

The GHG price forecast is taken from 2013 IEPR Mid Case. The 2013 IEPR forecast is based on current Cap-and-Trade and Trade regulation continuing through 2020. It assumes a high probability that complementary policies reduce emissions through 2017, but that the availability of complementary policies diminishes after 2017.[12]

This assumption is based on analysis presented in a report "Forecasting Supply and Demand Balances in California's Greenhouse Gas Cap-and-Trade Market" March 12, 2013. This reported was prepared by members of the Emissions Market Assessment Committee and the Market Simulation Group. The mid case scenario increase in price of 1.5 times the low energy consumption scenario is based on the Economic Analysis done in support of the regulations to implement the California Cap-and-Trade program. (Appendix N, page N-13).

[12] Based on analysis presented in a report "Forecasting Supply and Demand Balances in California's Greenhouse Gas Cap-and-Trade Market" March 12, 2013. This reported was prepared by members of the Emissions Market Assessment Committee and the Market Simulation Group. The mid case scenario increase in price of 1.5 times the low energy consumption scenario is based on the Economic Analysis done in support of the regulations to implement the California Cap-and-Trade program. Appendix N, page N-13.

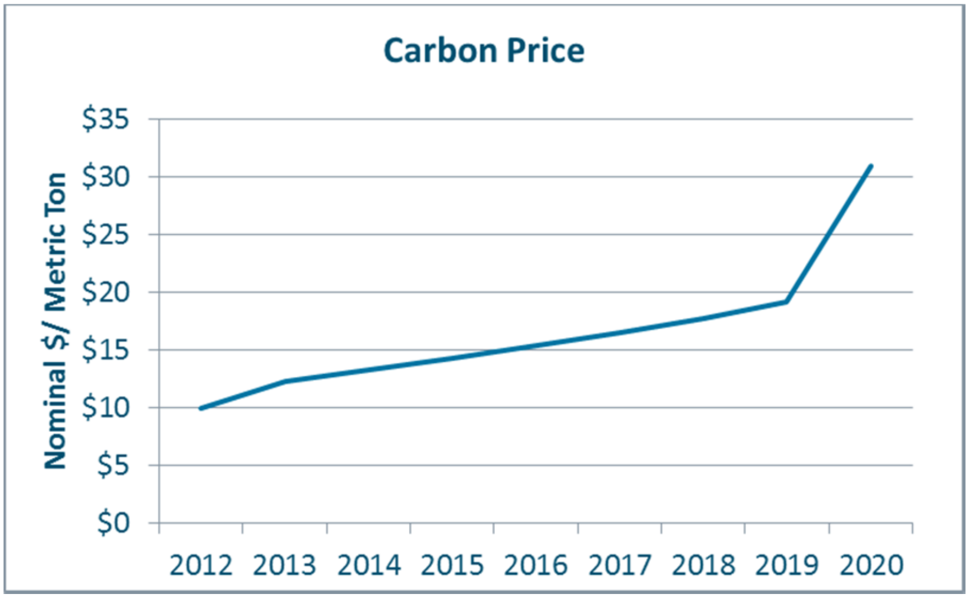
2013 beginning price is calculated based on the 2013 Vintage Allowances for all five auctions (November 2012, February 2013, May 2013, August 2013 and November 2013) Settlement Price weighted by the quantity (metric ton) sold.[13]

Table 7. 2013 Vintage Allowance Auction Prices

	2013 Vintage Settlement Price ($/metric ton)	Quantity Sold (metric tons)
14-Nov-12	10.09	23,126,110
19-Feb-13	13.62	12,924,822
16-May-13	14.00	14,522,048
16-Aug-13	12.22	13,865,422
19-Nov-13	11.48	16,614,526
Allowances Not Auctioned		81,747,072
Total Allowances for 2013		162,800,000

[13] http://www.arb.ca.gov/cc/capandtrade/auction/auction.htm

Figure 15. 2013 IEPR Mid Case GHG Price Forecast.



4.3 DER Avoided Cost Model Inputs

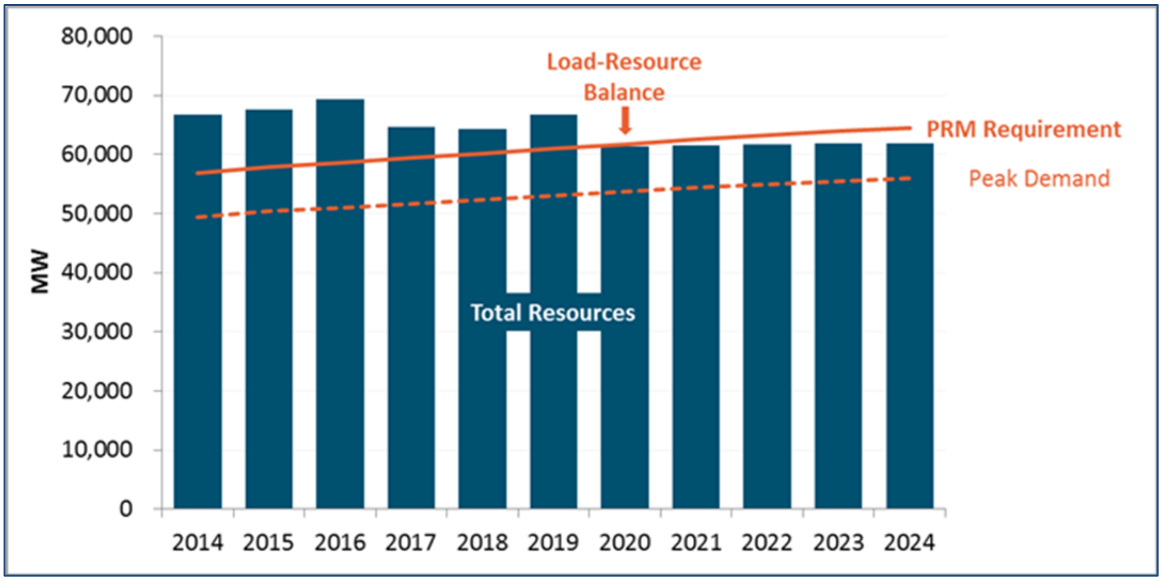
The avoided cost methodology developed by E3 has been updated and improved through several CPUC and CEC proceedings for use in evaluating distributed energy resources (DER) including energy efficiency, demand response and distributed generation. The most recent update was performed by E3 for the 2013 Net Energy Metering Cost-effectiveness Evaluation. This section describes inputs and assumptions from the DER Avoided Cost Model that are also used in the 2016 TDV Update.

4.3.1 RESOURCE BALANCE YEAR

The resource balance year represents the first year in which system capacity would be insufficient to meet peak period demand plus the reserve margin. In the evaluation of the avoided cost of electricity, the determination of the resource balance year represents the point at which the forecasts for energy and capacity value transition from short-run to long-run time scales; after this point, the energy and capacity values should capture the all-in costs of the new plants whose construction would be required to maintain resource adequacy. The avoided cost after the resource balance year is therefore based on the long run marginal avoided cost of new electricity generation.

The resource balance is projected using load and resource assumptions based on the CPUC's 2014 Long Term Procurement Plan (R.13-12-010).[14] These assumptions reflect the retirement of OTC generators and other aging infrastructure, the addition of planned fossil and renewable resources, and the growth of load over this period. To determine the resource balance year for the purposes of building standards, the load impact of incremental energy efficiency has been removed. In this manner, the value of capacity resources deferred by energy efficiency is included in the TDVs.

Figure 16: Resource Balance Year



4.3.2 SYSTEM CAPACITY AND CAPACITY COST ALLOCATION

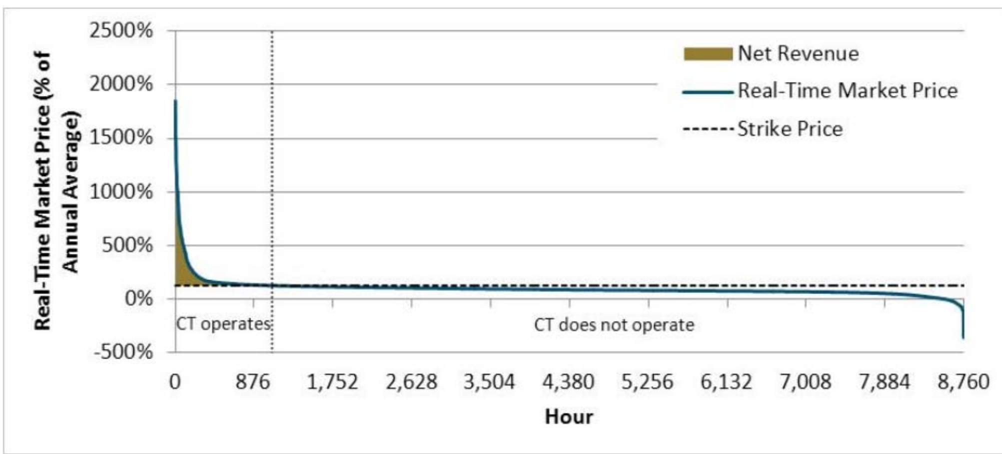
The generation capacity value captures the reliability-related cost of maintaining a generator fleet with enough capacity to meet each year's peak loads. Capacity value is calculated as the difference between the cost of a combustion turbine (CT) and the margins that the CT could earn from the energy markets.

As the resource balance year is 2017, the capacity value is calculated using the cost of a proxy simple-cycle combustion turbine (CT) to represent long-term capacity value throughout the analysis. Short-term Resource Adequacy values that were used in the 2013 TDV update are not applicable. The long-run

[14] See ScenarioTool2014inExcelv1c.xlsx (March 18, 2014) at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm

capacity value is equal to the CT's annualized fixed cost less the net revenues it would earn through participation in the real-time energy and ancillary services markets—this figure is the "capacity residual." The TDV methodology calculates the capacity residual of the CT for each year of the avoided cost series by dispatching a representative unit against an hourly real-time market price curve and subtracting the net revenues earned from the unit's fixed costs. The hourly shape of the real-time market is based on historical real-time data gathered from CAISO's MRTU system; in each year, the level of the curve is adjusted by the average wholesale market price for that year. The CT's net revenues are 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 10% bid adder, earning the difference between its operating cost and the market price. In each hour where the market prices are below the operating cost, the unit is assumed to shut down, illustrated in Figure 17 below.

Figure 17. Calculation of Capacity Cost using Net Revenue of a Combustion Turbine (CT)



The net revenues earned through this economic dispatch are grossed up by 11% to account for profits earned through participation in CAISO's ancillary services markets. The final figure is subtracted from the CT's annualized fixed cost—calculated using a pro-forma tool to amortize capital and fixed operations and maintenance costs—to determine the CT residual in that year.

The CT's rated heat rate and nameplate capacity characterize the unit's performance at ISO conditions,[15] 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. Based on the performance characteristics of the GE LM6000 "Sprint" technology, E3 has made the following temperature-based adjustments to the calculation of the capacity value

- 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 de-rate (by approximately 1% per 2.5 degrees above 60 degrees Fahrenheit). Consequently, the value of capacity is increased by approximately 9% to reflect the plant's reduced output during the top 250 load hours of the year.

The valuation of capacity includes an adjustment for losses between point of generation and delivery. In order to account for losses, the annual capacity value is multiplied by the utility-specific loss factor applicable to the summer peak period, as this is the period during which system capacity is likely to be constrained.

The loss-adjusted forecast of capacity value is further grossed up by 115% to reflect savings in the planning reserve margin (PRM). The California Public Utilities Commission requires each load-serving entity to maintain enough capacity to meet its peak demand plus a planning reserve margin of 15%.

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

Based on the PRM requirement a peak load reduction of a single kilowatt would reduce the amount of capacity needed by 1.15kW.

4.3.2.1 Effective Load Carrying Capacity Allocation of Capacity Value

Previously, capacity value was allocated over the top 250 load hours of the year, using load level to determine the weighting of this capacity value. E3 has refined the methodology to move away from using the load proxy and instead use ELCC calculated based on Loss-of-Load-Probability (LOLP).

The proprietary nature of utility LOLP models and results has historically been a hindrance to the incorporation of LOLP into this avoided cost framework. To solve this problem E3 has developed a non-proprietary LOLP model that uses publically available information.

The E3 Capacity Planning Model[16] estimates LOLP for each month/hour/day-type combination during the year based on net load (gross load net of non-dispatchable renewable resources). These values directly express the likelihood of lost load, and therefore give a more accurate relative weighting among hours. These tables have been calculated using the E3 Capacity Planning Model for the present day as well as a 2020 case representing the RPS build out from the 2010 LTPP Trajectory Case.

Figure 18: 2013 LOLP Table

Weekday

Month → / Hour ↓

0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	6E-15	0	0	0	0	0
0	0	0	0	0	0	7E-11	2E-13	4E-15	0	0	0
0	0	0	0	0	0	2E-08	5E-09	2E-11	0	0	0
0	0	0	0	0	5E-15	3E-06	3E-06	7E-08	0	0	0
0	0	0	0	2E-15	2E-13	9E-05	3E-05	1E-05	0	0	0
0	0	0	0	2E-14	1E-09	8E-04	4E-04	5E-04	3E-15	0	0
0	0	0	0	5E-12	3E-07	0.002	0.003	0.001	7E-13	0	0
0	0	0	0	8E-11	6E-06	0.004	0.006	0.002	3E-11	0	0
0	0	0	0	4E-11	9E-06	0.003	0.006	0.002	3E-13	0	0
0	0	0	0	1E-12	9E-07	7E-04	0.002	3E-04	4E-15	0	0
0	0	0	0	2E-15	6E-09	4E-05	3E-04	1E-04	0	0	0
0	0	0	0	0	7E-11	3E-05	2E-05	5E-05	0	0	0
0	0	0	0	0	1E-11	3E-07	3E-06	4E-07	0	0	0
0	0	0	0	0	0	3E-11	6E-10	2E-14	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0

Weekend

Month → / Hour ↓

0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	8E-15	4E-15	2E-15	0	0	0
0	0	0	0	0	2E-15	9E-12	4E-13	8E-13	0	0	0
0	0	0	0	0	1E-13	3E-04	3E-10	4E-10	0	0	0
0	0	0	0	0	2E-13	6E-04	1E-08	1E-08	0	0	0
0	0	0	0	0	2E-12	7E-04	3E-07	7E-08	0	0	0
0	0	0	0	0	2E-12	3E-04	2E-07	8E-08	0	0	0
0	0	0	0	0	3E-13	9E-05	1E-08	2E-08	0	0	0
0	0	0	0	0	3E-15	1E-05	9E-10	4E-10	0	0	0
0	0	0	0	0	0	7E-08	1E-11	5E-09	0	0	0
0	0	0	0	0	0	5E-14	7E-13	2E-12	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0

[16] The E3 Capacity Planning Model and the Dispatchability Factor Calculator, including user's manuals, are available online at https://e3.sharefile.com/d/s78313505eea47ffb.

Figure 19: 2020 LOLP Table

Weekday (Month →, Hour ↓)

0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	2E-15	0	0	0	0	0
0	0	0	0	0	0	5E-11	1E-13	8E-16	0	0	0
0	0	0	0	0	0	1E-08	8E-09	5E-12	0	0	0
0	0	0	0	0	0	1E-06	1E-06	1E-07	0	0	0
0	0	0	0	3E-16	1E-15	3E-05	7E-06	9E-06	0	0	0
0	0	0	0	7E-16	6E-11	4E-04	2E-04	2E-04	8E-16	0	0
0	0	0	0	1E-12	2E-07	9E-04	0.001	6E-04	6E-12	0	0
0	0	0	0	1E-10	4E-06	0.003	0.004	0.001	7E-10	0	0
0	0	0	0	2E-10	7E-06	0.002	0.005	0.001	2E-12	0	0
0	0	0	0	4E-12	2E-06	8E-04	0.003	9E-04	7E-15	0	0
0	0	0	0	1E-15	3E-08	2E-04	0.002	0.003	0	0	0
0	0	0	0	0	2E-08	5E-04	1E-03	0.003	0	0	0
0	0	0	0	0	7E-09	1E-04	4E-04	2E-04	0	0	0
0	0	0	0	0	7E-15	2E-08	2E-07	1E-12	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0

Weekend (Month →, Hour ↓)

0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	9E-16	8E-16	3E-16	0	0	0
0	0	0	0	0	2E-16	1E-13	2E-15	6E-14	0	0	0
0	0	0	0	0	5E-16	9E-05	4E-11	1E-10	0	0	0
0	0	0	0	0	5E-16	2E-04	3E-09	2E-08	0	0	0
0	0	0	0	0	3E-14	4E-04	5E-07	2E-07	0	0	0
0	0	0	0	0	7E-14	3E-04	7E-07	6E-07	0	0	0
0	0	0	0	0	2E-14	1E-04	4E-08	1E-07	0	0	0
0	0	0	0	0	8E-16	5E-05	1E-08	8E-08	0	0	0
0	0	0	0	0	0	2E-05	1E-09	4E-06	0	0	0
0	0	0	0	0	0	3E-12	3E-11	4E-10	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0

These likelihoods are then adjusted to reflect expected variations within each month/hour/day-type. The LOLP table provides a single value for a weekday in July at 4 PM. However, spreading that value uniformly over every 4 PM during a July weekday, and following suit with each other month/hour/day-type, would distribute the capacity value over some 500 hours of the year. The adjustment step described herein recognizes that some weekdays are hotter than others, which naturally leads to higher loads and higher probability of lost load on those days. Given this, we use a temperature threshold to label certain days of the year as high load days, and distributed the LOLP from the above tables to only the high load days. The result is a set of capacity allocation factors that distributes value to between 150 and 250 hours of the year.

4.3.2.2 Allocation Methodology

The following section details the steps used to distribute calculated LOLP values for each month/hour/day-type to statistically determined “hot days” based on TMY weather data.

1. **Use TMY weather data to calculate lagged max daily temperature for each weather region**

   The highest load events that typically result in loss of load are caused by several consecutive hot days. As a result, we create a lagged temperature variable that captures this effect. In the formula, LT_i is the lagged maximum temperature for day i, and T_i is the maximum temperature for day i.

   $LT_i = T_i/2 + T_{i-1}/4 + T_{i-2}/6 + T_{i-3}/12$

2. **Combine load-weighted regional temperatures to develop a single statewide representative temperature**

   Each of the regions in Step 1 is given a weight based on historical peak load relative to statewide peak load. These weights are multiplied by each region's stream of daily lagged maximum temperatures, and combined, across all regions, to create a statewide lagged maximum temperature for each day of the TMY.

3. **Find the threshold temperature representative of 1 in 10 load**

   Using the methodology described in Steps 1 and 2, and the same weather stations identified in Step 1, a stream of statewide daily lagged maximum temperatures is created for each historical year for which sufficient data is available. The 90th percentile of this set of lagged temperatures is then established as the threshold temperature for high load days. Days with lagged maximum temperature less than this value are deemed to not result in lost load. Meanwhile days with lagged maximum temperature greater than this value are labeled as high load days.

4. **Distribute LOLP across days that classify as high load days**

   Days having a lagged maximum temperature (found in Step 2) that exceeds the high load temperature threshold (found in Step 3) are labeled as high load days within the TMY. Then, the previously calculated LOLP values are distributed across hours that occur on high load days. Hours on non-high load days receive no allocation. Finally, the annual stream of hourly values is normalized to sum to 1. The resulting normalized values are the hourly capacity allocation factors for the TMY.

Two example capacity allocation duration curves are shown below (Figure 20 and Figure 21). The two curves shown use the same set of TMY weather data to determine high load days across which LOLP values are distributed, but use two separate sets of annual LOLP values. These two sets represent LOLP conditions in 2013 and under a 2020 Trajectory scenario. Note that the higher concentration of solar resources in the 2020 Trajectory case suppresses the LOLP values in the highest hours, thereby flattening the entire curve. Values for the years between 2013-2020 are interpolated. Capacity allocators after 2020 are held constant.

Figure 20: Resulting Capacity Allocation Duration Curves

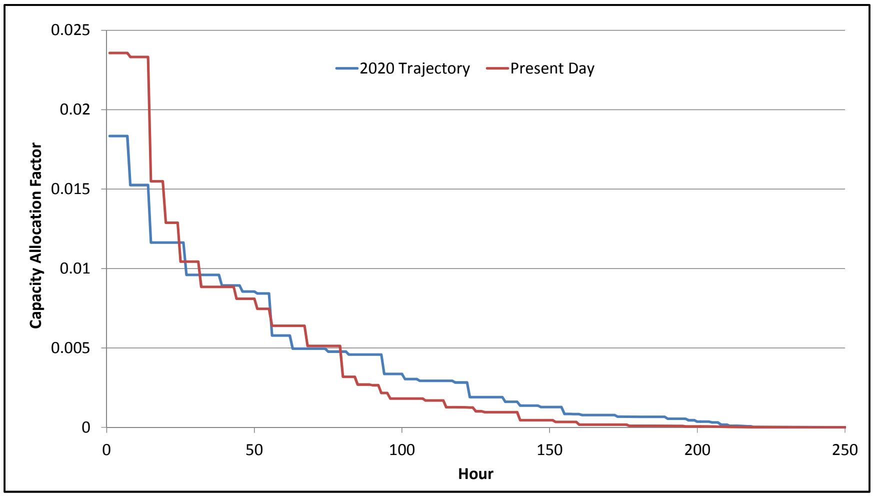
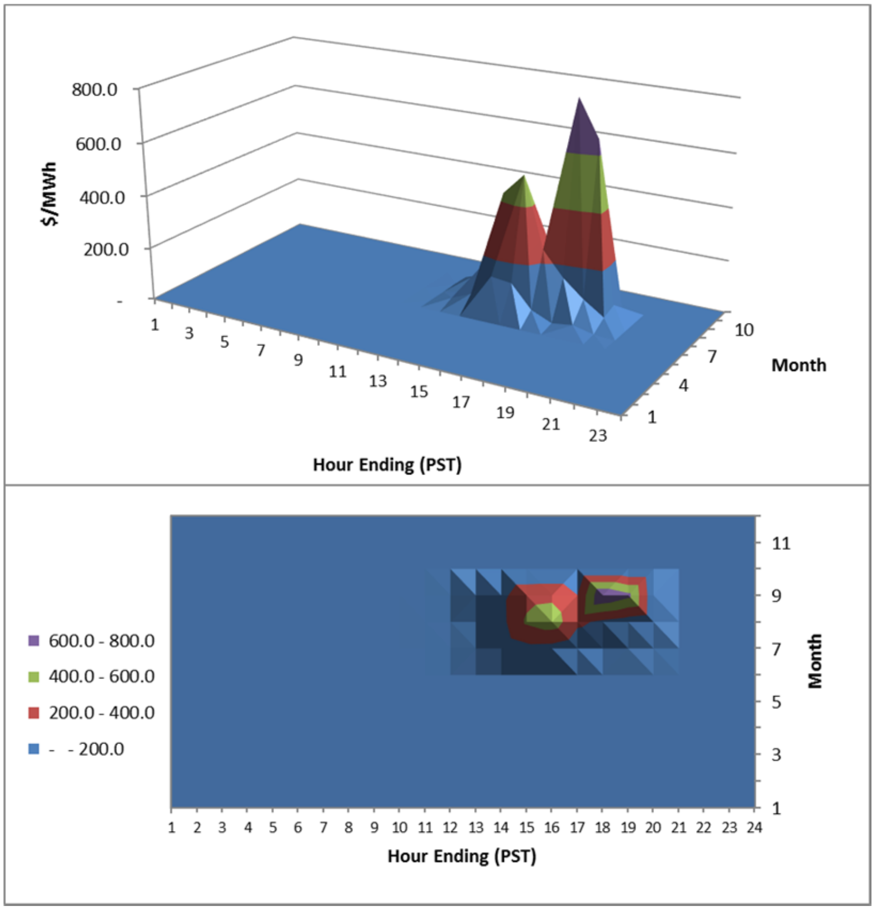


Figure 21: Average Allocation of Generation Capacity Value (CZ 12)



4.3.3 CT COST AND PERFORMANCE

Cost and performance assumptions for a new simple cycle gas turbine, used in the capacity cost calculation, are based on the 2014 California Energy Commission's Cost of Generation report (COG Report). In prior years the conventional CT was used as the proxy resource for new capacity. However there is an increasing focus on the need flexible capacity resources that have lower minimum generation levels (Pmin) and are capable of more frequent and faster stops and starts. For the 2016 TDV Update we therefore use the Advanced CT from the COG Report. A comparison of the cost and performance assumptions for the two technologies is shown in Table 8.

Table 8. 2014 CEC Cost of Generation Report Performance and Cost Assumptions ($2013)

Metric	Conventional CT (LM6000). (For comparison only)	Advanced CT (LMS100)	Notes
Heat rate	10,585	9,880	Table 39
Useful Life	30	30	
Instant Cost	$1,303	$1,261	Table 51, Merchant
Installed Cost	$1,457	$1,410	Table 51, Merchant
Fixed O&M	28.39	25.24	Table 52, 2013 Nominal
Variable O&M	0	0	Table 52, 2013 Nominal

As in prior years, E3 used different financing assumptions for the TDV update that are different than those in the CEC COG Report. The financing assumptions for the TDV update are selected to represent average financing costs over the 15 and 30 term of the TDV calculations, whereas the COG Report reflects current market conditions. Thus the TDV assumes a higher cost of debt, to reflect on long-term historical averages for non-recourse loans used in power plant project financing, whereas the COG Report assumption is based on the current low interest rate environment. The 2016 TDV assumptions are also designed to reflect an After-Tax Weighted Average Cost of Capital (WACC) that is based on the asset being financed, rather than the company ownership (e.g. IOU vs. Merchant) as is done in the COG

Report. Again long-term historical average WACCs for fossil generation assets is around 8%.[17] Finally, the 2016 TDV assumes that projects are financed based on a 20 year power purchase agreement (PPA), though the actual useful life of the asset is longer. In the end, however, the two approaches arrive as similar levelized fixed: the 2016 TDV Update result of $193/kW-Yr. is just $10 lower than the CEC COG Report result of $203/kW-Yr.

Table 9. Comparison of Financing Assumptions for CEC COG Report and 2016 TDV Update

	CEC COG Report	2016 TDV Update
Useful Life (Years)	30	20
Debt-to-Equity Ratio	67%	50%
Debt Cost	4.5%	7.7%
Equity Cost	13.25%	12%
After-Tax WACC	6.2%	8.3%
Levelized Fixed Cost ($kW-Yr.)	$203	$193

4.3.4 ANCILLARY SERVICES (A/S)

The value of avoided ancillary services procurement is treated as a flat percentage multiplier on top of the energy value. This approach reflects the fact that the value of ancillary services is mildly correlated with the value of energy in any given hour, but other factors also affect the value of A/S. Since the overall value of A/S remain relatively small in the market, it is appropriate to use an approximation, based on a multiplier of 1% of the energy value in each year. This multiplier is based on California Independent System Operator (CAISO MRTU) market prices for energy and reserves from 2009-2010. The new CAISO market design has substantially reduced ancillary service costs. Load reduction (e.g. efficiency) is only credited with the value of avoided procurement of spinning and non-spinning reserves.

4.3.5 TRANSMISSION AND DISTRIBUTION CAPACITY & COST ALLOCATION

The avoided costs include the value of the potential deferral of transmission and distribution (T&D) network upgrades that could result from reductions in local peak loads. E3 gathered utility estimates of

[17] See Presentation of Michelle Chait at May 16, 2011 Staff Workshop on Improving Techniques for Estimating Costs of California Generation Resources http://www.energy.ca.gov/2011_energypolicy/documents/index.html#05162011

T&D marginal capacity costs from the general rate case filings of PG&E, SCE, and SDG&E[18]. Using these data, E3 calculated load-weighted statewide average capacity values for T&D. As with generation energy and capacity, the value of T&D capacity is adjusted for losses during the peak period. The T&D loss factors are shown in the table below. These factors are lower than the energy and capacity adjustments because they represent losses from transmission and distribution voltage levels to the retail delivery point, rather than from the generator to the load.

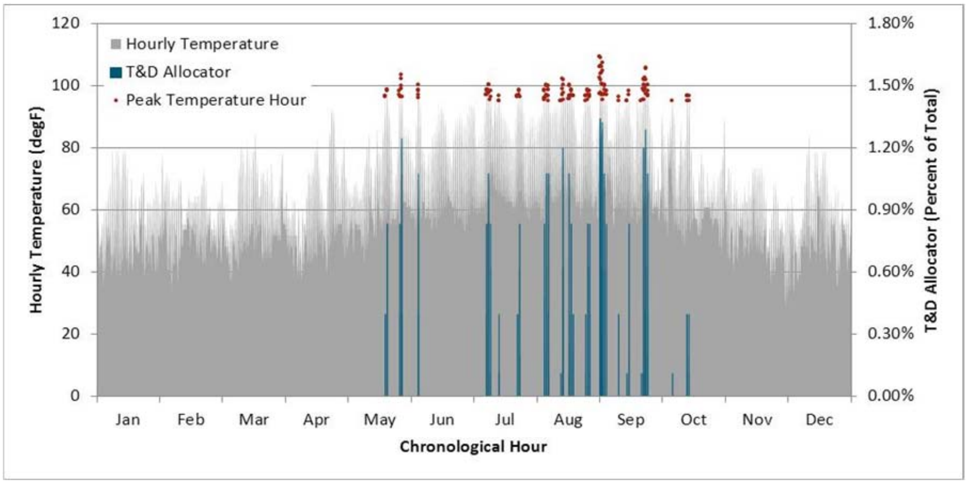
Table 10. Losses during peak period for capacity costs

	PG&E	SCE	SDG&E
Distribution	1.048	1.022	1.043
Transmission	1.083	1.054	1.071

Since the network constraints of a distribution system must be satisfactory to accommodate each area's local peaks, the TDV methodology allocates the capacity value of T&D in each 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 generally correlated with hourly temperatures, we use hourly temperatures as a proxy for loads to develop allocation factors for T&D value. This methodology was benchmarked against actual local load data in the 2005 Title 24 update, and has been used in all subsequent updates. To illustrate, the T&D allocators for Climate Zone 2 are shown in the figure below.

[18] PG&E 2014 GRC Phase II, SCE 2011 GRC Phase II, and SDG&E GRC Phase II Application 11-10-002.

Figure 22. Allocation of T&D Costs (CZ 12)

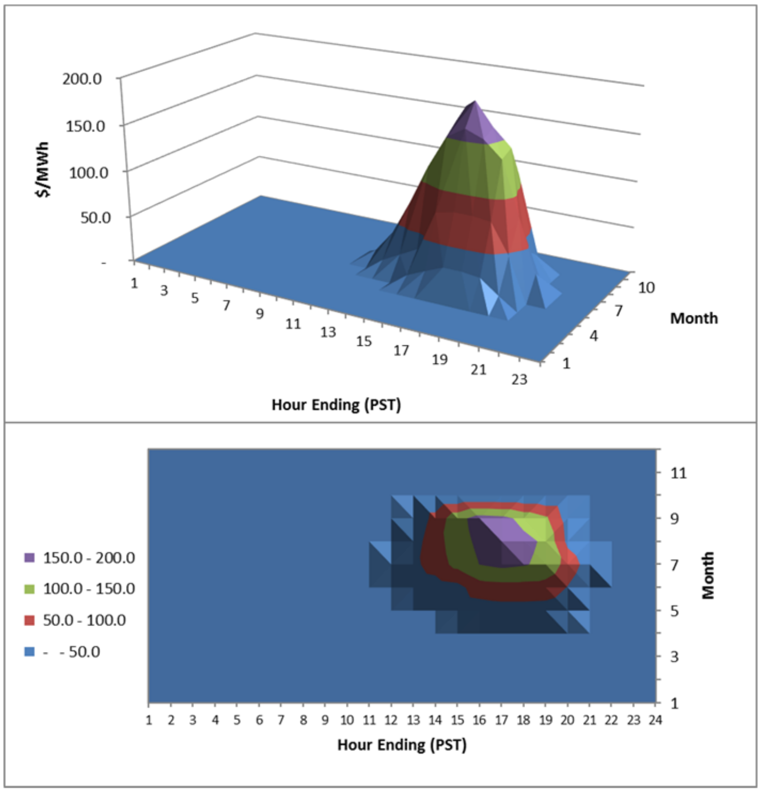


The following is a brief description of the algorithm used to allocated T&D capacity value. T&D capacity value is allocated to all hours with temperatures within 15ºF of the peak annual temperature.

1. Select all hours with temperatures within 15ºF of the peak annual temperature (excluding hours on Sundays 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.

We make one further adjustment to this methodology for Climate Zone 1 (Arcata). In this Northern region, there are relatively few high temperature days, and also relatively low penetrations of air conditioners in homes and businesses. As a result, in Climate Zone 1, high temperature days are unlikely to result in the spikes in electricity demand that we see in other regions of California that have air conditioning loads which increase with higher temperatures. Unless we adjust the T&D cost allocation methodology for this region, Climate Zone 1 would show a high allocation of T&D costs to relatively few hours, resulting in high price spikes in those few hours. To spread the allocation of T&D deferral value over more hours in this climate zone, allocators are calculated for each hour within 19ºF of the peak temperature. Hours within 4ºF of the peak annual temperature are assigned the same allocator. This adjustment spreads the T&D capacity value over a larger number of hours and is justified because of the weaker correlation between temperature and peak load in this climate zone. The resulting allocation of T&D capacity costs are shown in Figure 23.

Figure 23. Average Allocation of T&D Costs (CZ 12)



4.3.6 MARGINAL EMISSIONS RATE

The CO_2 price forecast affects the cost of generation differently in different hours of the year, depending on what type of generator is operating on the margin. In California, it is generally safe to assume that natural gas is the marginal fuel in all hours. Thus, the hourly emissions rate of the marginal generator is calculated based on the same production simulation model results of the marginal generation price curve used elsewhere in the analysis. This hourly emissions curve is adjusted using the same loss factors as the hourly energy value to reflect the emissions reduction consistent with a reduction in retail load.

There is a direct link between higher market prices and higher emissions rates since higher market prices enable lower-efficiency generators to operate, resulting in increased rates of emissions at the margin.

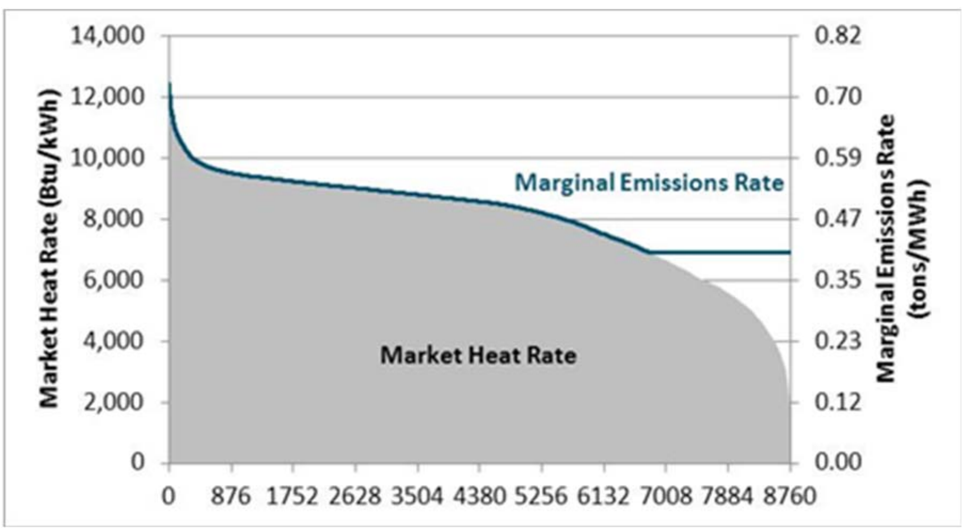
Of course, this relationship holds for a reasonable range of prices but breaks down when prices are extremely high or low. For this reason, the avoided cost methodology bounds the maximum and minimum emissions rates based on the range of heat rates of gas turbine technologies. The maximum and minimum emissions rates are bounded by reasonable ranges of heat rates for the "best" and "worst" performing natural gas plants shown in Table 11.

Table 11. 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 24, below, shows the hourly market heat rates in California sorted from highest to lowest, as well as the implied marginal emissions rate of generation based on this heat rate.

Figure 24. Estimated Marginal Emissions Rate of Generation Based on Hourly Market Heat Rates

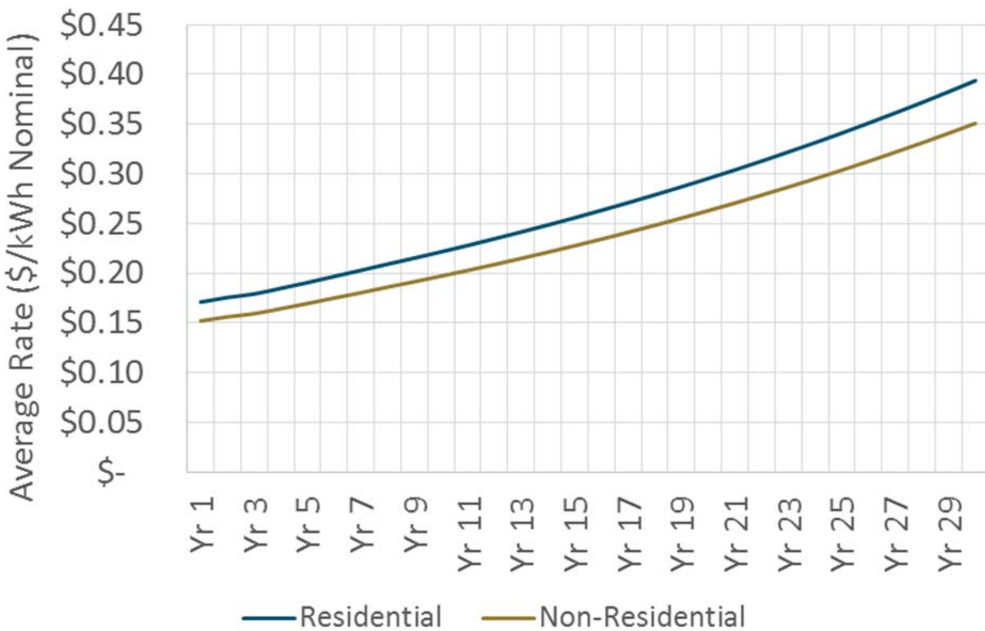


4.3.7 RETAIL RATE ADJUSTER

The final step in the process of developing TDV cost values is to adjust the hourly wholesale cost of energy up to the equivalent of the retail cost of energy. This step is done to ensure that the energy efficiency measures considered in the Title 24 standards process are roughly cost effective to the building owner. In other words, the TDVs reflect a modified (time-dependent) participant cost test approach to avoided costs.

A statewide retail rate forecast for residential and nonresidential customers is developed for the electricity TDVs. The electricity rate forecasts are developed from the 2013 IEPR. The IEPR calculates average residential and commercial rates for PG&E, SCE, and SDG&E through 2024 (2013 IEPR Form 2.3). For the 2016 TDVs, the utility-specific rates are combined into a statewide weighted average using electricity consumption forecasts from 2013 IEPR Form 1.1. After 2024, the rate forecasts are escalated using the compound average growth rate observed from 2017 through 2024 (2.9%/yr. nominal increase for both residential and non-residential). Figure 25 shows the retail rate forecast.

Figure 25. Forecast of Retail Rates Used in Calculation of Hourly TDVs



4.3.8 RPS ADDER

An addition benefit of electricity usage reduction is the avoided cost of renewable purchases. Because of California's commitment to reach a RPS portfolio of 33% of total retail sales by 2020, any reductions to total retail sales will result in an additional benefit by reducing the required procurement of renewable energy to achieve RPS compliance. This benefit is captured in the avoided costs through the RPS Adder. The components of the RPS Adder calculation are summarized in Table 12.

Table 12. Components for Calculation of RPS Adder (in year "Y")

Component	Formula
RPS $Adder_y$	= RPS $Premium_y$ * Compliance $Obligation_y$
RPS $Premium_y$	= Annual above-market costs of renewable generation
Compliance $Obligation_y$	= Annual % of retail sales required to be met with renewable generation

The RPS Adder captures the value that a reduction in load brings to ratepayers through a reduction in required procurement to comply with the state's Renewable Portfolio Standard. Because the state's current RPS policy requires each utility procure renewable generation equivalent to 33% of its retail sales in 2020, each 1 MWh reduction in load in 2020 reduces a utility's compliance obligation by 0.33 MWh. This reduction in a utility's compliance obligation translates directly to a ratepayer benefit through a reduction in the above-market cost of resources used to serve load.

The first step to calculate the RPS Adder is to evaluate the RPS Premium, a measure of the above-market cost of the assumed marginal renewable resource. The RPS Premium is a function of assumed PPA cost of the marginal resource as well as the incremental costs of transmission and integration and the energy, capacity, and emissions reduction value provided by that resource:

Figure 26. Components of the RPS Premium

	PPA Price
+	Incremental Transmission Cost
+	Integration Cost
-	Energy $Value_y$
-	Emissions $Value_y$
-	Capacity $Value_y$
=	RPS $Premium_y$

For this analysis, E3 has assumed that the marginal renewable resource is solar PV, the resource with the highest net cost that utilities are currently procuring in large quantities. Data sources and calculation methodologies for each of the components of the RPS Premium are:

- The **PPA Price** of the marginal renewable resource is based on the CPUC's 2012 *Padilla Report to the Legislature: The Cost of Renewables in Compliance with Senate Bill 836.*[19] The marginal cost for 2012 is based on the average cost of all solar PV projects approved in 2012 ($98/MWh). This average cost is assumed to decline over time due to technological learning but increases sharply in 2017 due to the sunset of the ITC. The trend of assumed PV prices over time is based on a review of technology capital costs that E3 completed as an input to WECC's 10- and 20-year transmission planning studies.[20]
- The **Incremental Transmission Cost** associated with the marginal resource is assumed to be $54/kW-yr.[21] This is based on the standardized planning assumption used by the CPUC as an input to its 2010 LTPP. This cost is converted to a $/MWh basis assuming a 27% capacity factor.
- The **Integration Cost** is assumed to be $7.50/MWh for solar PV, reflecting the increased costs of carrying reserves to balance the intermittency of central station solar PV output.[22]
- The **Energy Value** associated with solar PV is calculated endogenously in the avoided cost model based on an assumed hourly PV production profile and the hourly cost of energy in each year.
- The **Emissions Value** is calculated endogenously based on the same PV production profile used to determine the energy value, hourly marginal emissions rates, and the annual cost of carbon.
- The **Capacity Value** is determined based on an assumed marginal ELCC and the endogenous capacity value determined by the avoided cost model. The marginal ELCC is assumed to decline from 53% to 40% between 2013 and 2020 reflecting increasing solar penetrations as the state approaches 33%; thereafter, the marginal ELCC is assumed to remain constant as the compliance requirement remains at 33%.

4.3.9 LOSS FACTORS

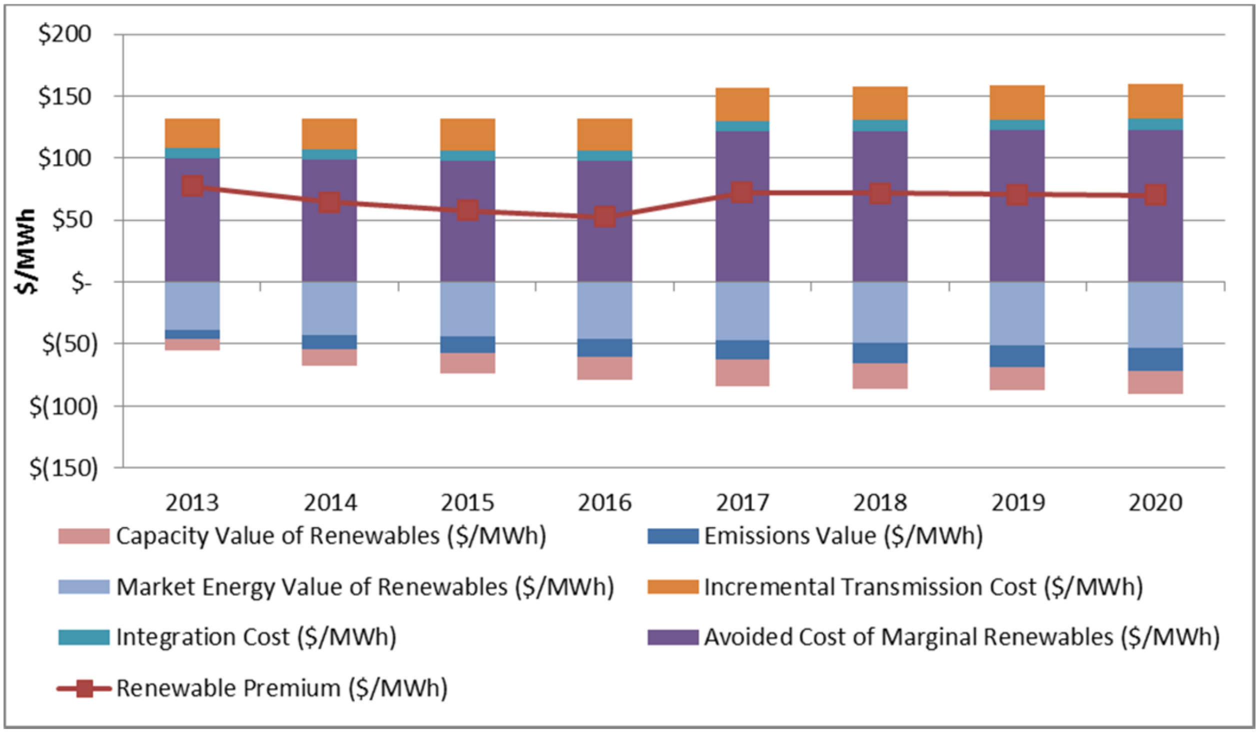
The hourly values of energy are adjusted by loss factors to account for losses between the points of wholesale transaction and retail delivery. The loss factors, which vary by utility, season, and TOU period and obtained from utility filings in rate proceedings before the CPUC (Table 13).

[19] See http://www.cpuc.ca.gov/NR/rdonlyres/F0F6E15A-6A04-41C3-ACBA-8C13726FB5CB/0/PadillaReport2012Final.pdf
[20] See http://www.wecc.biz/committees/BOD/TEPPC/TAS/121012/Lists/Minutes/1/%20121005_GenCapCostReport_finaldraft.pdf
[21] See http://docs.cpuc.ca.gov/efile/RULC/127544.pdf
[22] Ibid.

Table 13. Marginal energy loss factors by utility and time period

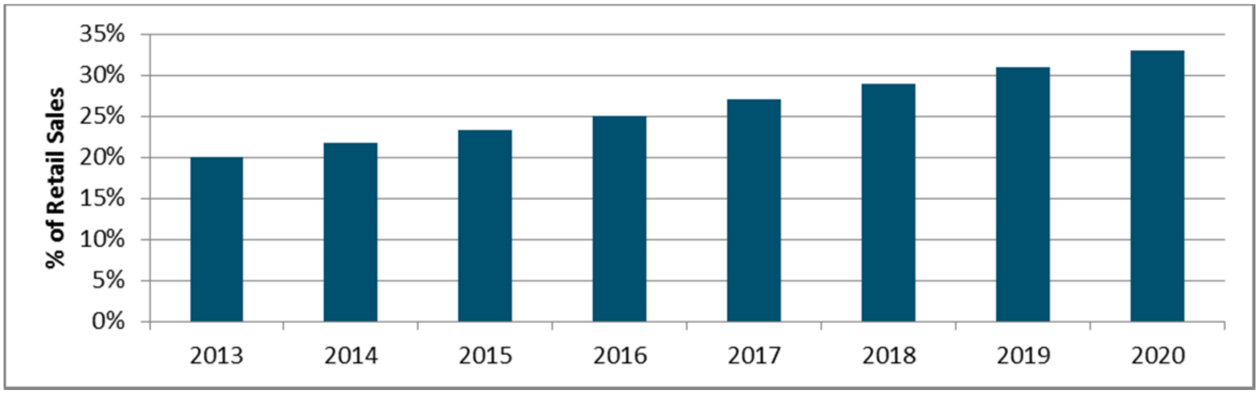
Time Period	PG&E	SCE	SDG&E
Summer Peak	1.109	1.084	1.081
Summer Shoulder	1.073	1.080	1.077
Summer Off-Peak	1.057	1.073	1.068
Winter Peak	-	-	1.083
Winter Shoulder	1.090	1.077	1.076
Winter Off-Peak	1.061	1.070	1.068

Figure 27: Annual Formulation of the RPS Premium



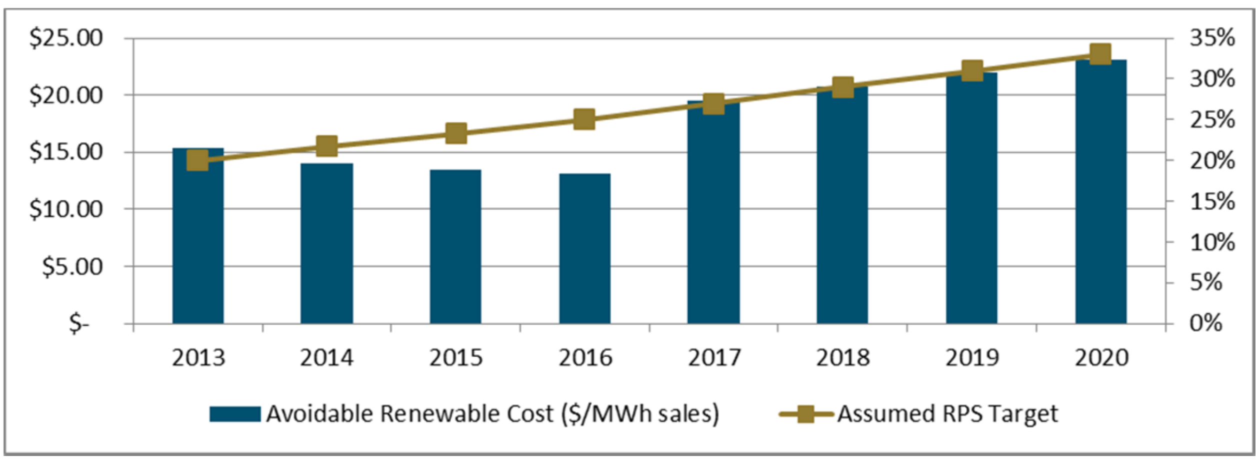
The RPS Adder is calculated by multiplying the RPS Premium by the statutory compliance obligation for the specified year. Current policy requires that utilities meet an RPS target that increases from 20% in 2011 to 33% by 2020. After 2020, E3 assumes that the compliance obligation remains at 33% of retail sales. For years before 2020, this compliance obligation is less than 33%.

Figure 28: Interim RPS Compliance Targets



CPUC Procurement Targets[23]

Figure 29: RPS Adder Calculated Based on the RPS Premium



[23] See http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33RPSProcurementRules.htm

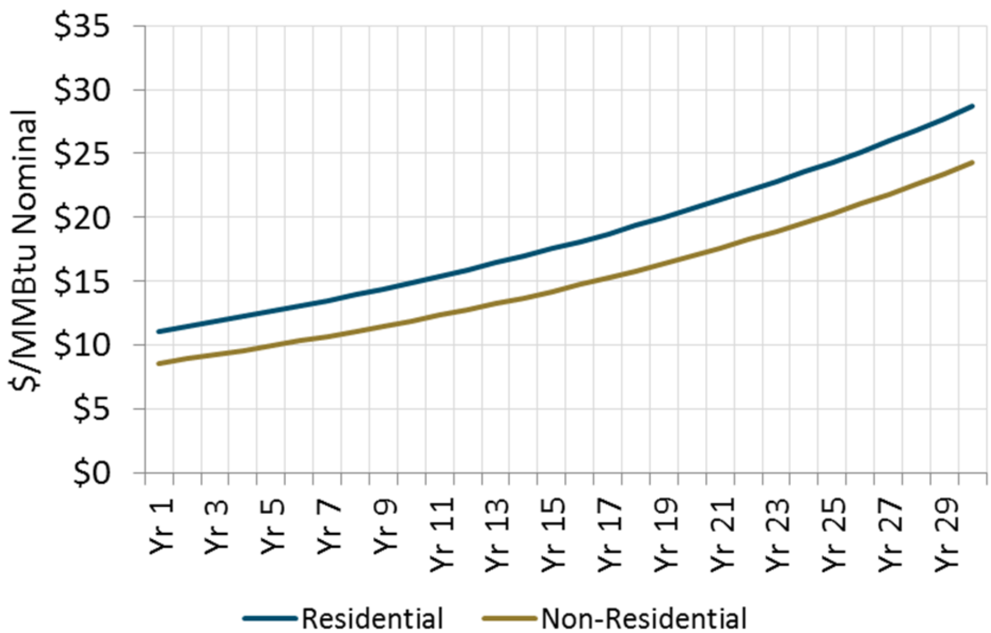
5 Natural Gas TDVs: Data Sources and Methodology

5.1 Components of TDV for Natural Gas

The natural gas TDV is based on a long-run forecast of retail natural gas prices and the value of reduced emissions of CO_2 and NO_x. The components are:

- Retail price forecast - The natural gas retail price forecast is taken from the 2013 IEPR (Table 14. Reference Case). The TDVs use the IEPR average statewide natural gas end-user prices for residential and commercial customers. The IEPR report presents prices for 2013, 2020, and 2025. We fill the intermediate years by linear interpolation, and extrapolate past 2015 using the 2020-2025 compound annual growth rate. The annual end user prices are also adjusted to reflect monthly variations in natural gas commodity costs. Those adjustment factors are the same as those used for the 2013 TDVs, and are based on historical NYMEX monthly natural gas price shapes at Henry Hub. The annual average natural gas retail price levels used in the natural gas TDVs are shown in Figure 30, below.

Figure 30. Natural Gas Retail Rate Forecast.



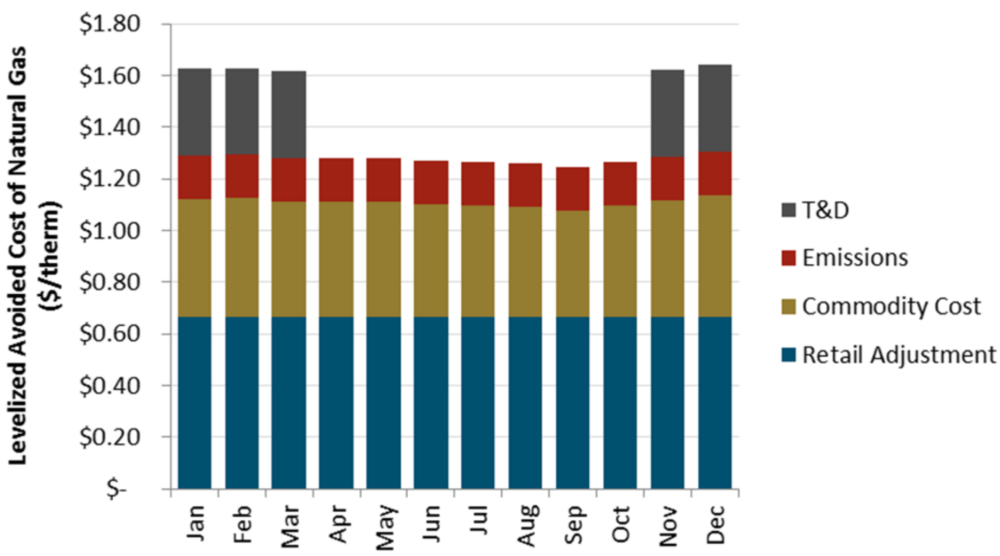
- Emissions Costs – Emission values are calculated based on the emissions rates of combusting natural gas in typical appliances. The NO_x and CO_2 emissions rates for natural gas combustion are derived from the CPUC's energy efficiency avoided cost proceeding (R.04-04-025).
- Distribution costs – Natural gas distribution costs include the cost of building and maintaining a natural gas pipeline distribution network. These costs are allocated to winter months, because demand for gas is highest in the winter.

In general, we seek to apply the same methodology to the development of the natural gas TDVs as to the electricity TDVs, in order to maintain as much parity between the fuel types as possible. In the case of greenhouse gas emissions and NOx emissions, this principle of parity requires a few adjustments to the natural gas TDVs. Since there is a market for NOx emissions in electricity generation, the cost of obtaining NOx permits is assumed to be included in the cost of electricity generation. However, there is no NOx emissions price for end-use natural gas combustion so we must adjust the natural gas TDV for the cost of NOx in order to treat this fuel equally with electricity.

The CO_2 price forecast impacts are kept consistent between the electricity TDVs and the natural gas TDVs. In the Base electricity TDVs, the CO_2 price affects the shape of the TDVs, but does not affect the overall level of the TDVs. This is because the market cost of CO_2 emissions is assumed to be refunded to ratepayers. The same logic is applied to the natural gas TDVs. Since CO_2 emissions do not vary by time period for natural gas combustion, the CO_2 adjustment does not affect the overall TDV shape or level for the natural gas TDVs.

Figure 31 illustrates the components of the natural gas avoided costs and the monthly variation in prices over the course of a year.

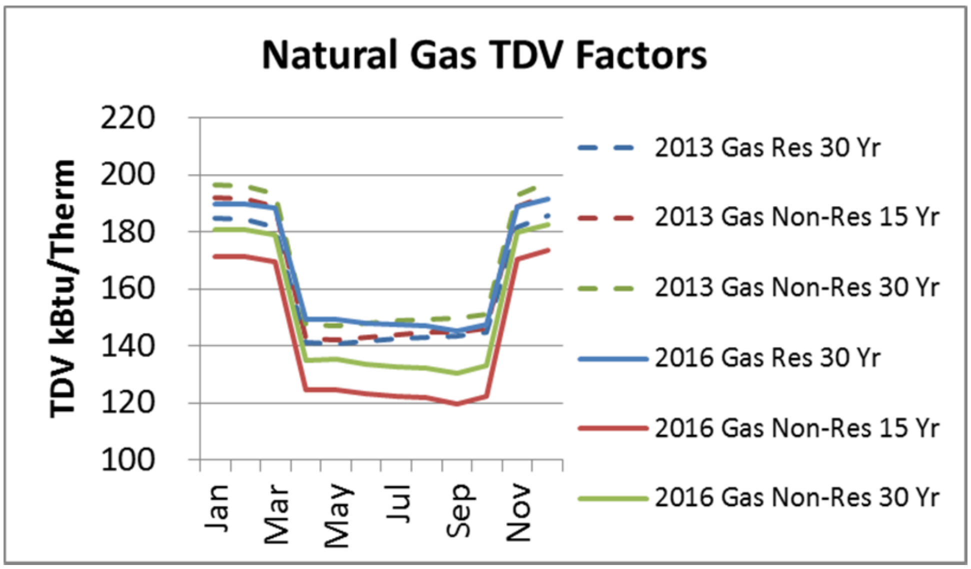
Figure 31. Monthly Variation in Natural Gas Avoided Costs



5.2 Results

A comparison of the 2016 to 2013 Natural Gas TDV Factors is shown in Figure 35. Note that the Non-residential TDV are lower in 2016 while the residential TDVs are higher, reflecting the different rate forecasts in Figure 1.

Figure 32. Comparison of 2013 and 2016 Propane TDV Factors



6 Propane TDVs: Data Sources and Methodology

6.1 Components of TDV for Propane Costs

The components of propane vary by month like natural gas. The components are:

+ Retail Cost - The propane forecast is based on the long-run U.S. Department of Energy (DOE) EIA 2013 Annual Energy Outlook Pacific region propane price forecast, and the TDV natural gas end user price forecast described above. The EIA forecast is through 2040, and a simple five year trend is used for the years 2040 through 2046. The residential propane price forecast equals the TDV natural gas residential price forecast multiplied by the ratio of the EIA residential propane price to the EIA natural gas residential price. The corresponding calculations are performed for the non-residential forecast using the Commercial customer prices from the EIA.

  Like natural gas, the propane annual retail price is shaped to reflect monthly cost variations using the shaping factors used for the 2013 TDVs.

+ Emissions Costs - The emissions costs are based on the same emissions prices used in the natural gas analysis.

Figure 33 shows the Propane cost price forecast used in the analysis.

Figure 33. Propane Retail Rate Forecast

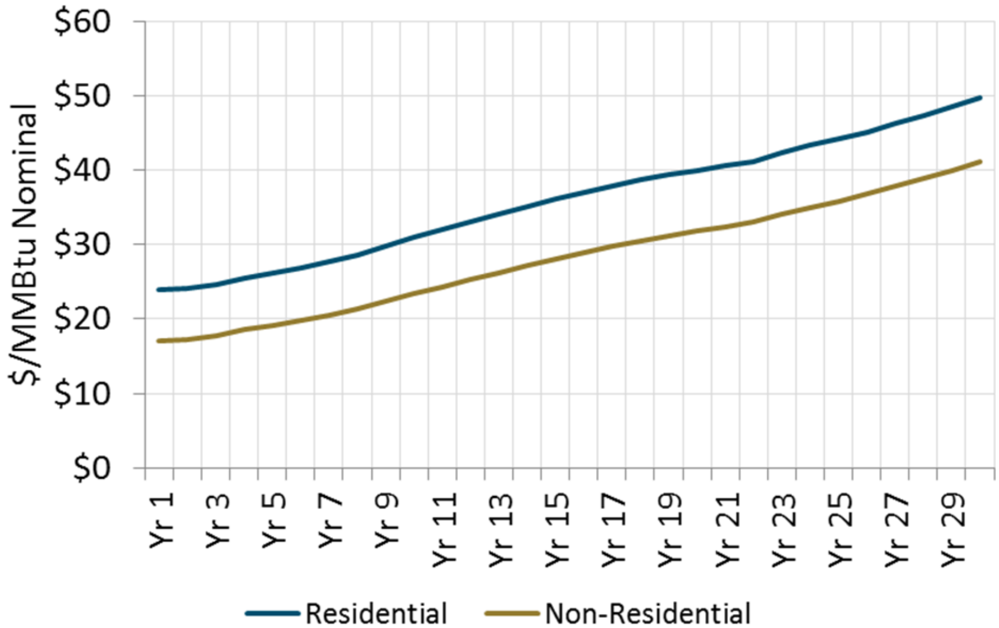
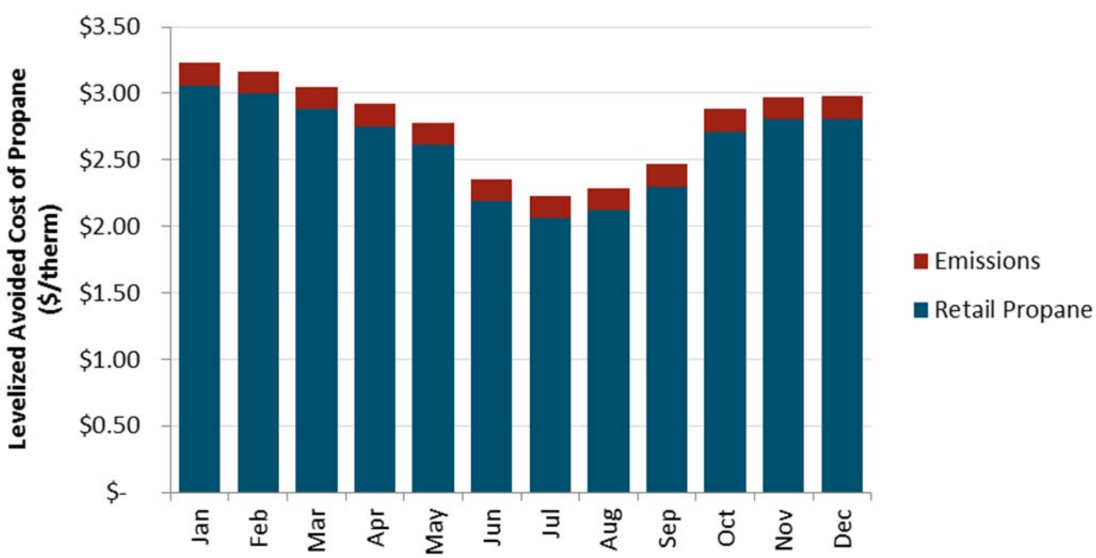


Figure 34 shows the monthly variation of the propane costs.

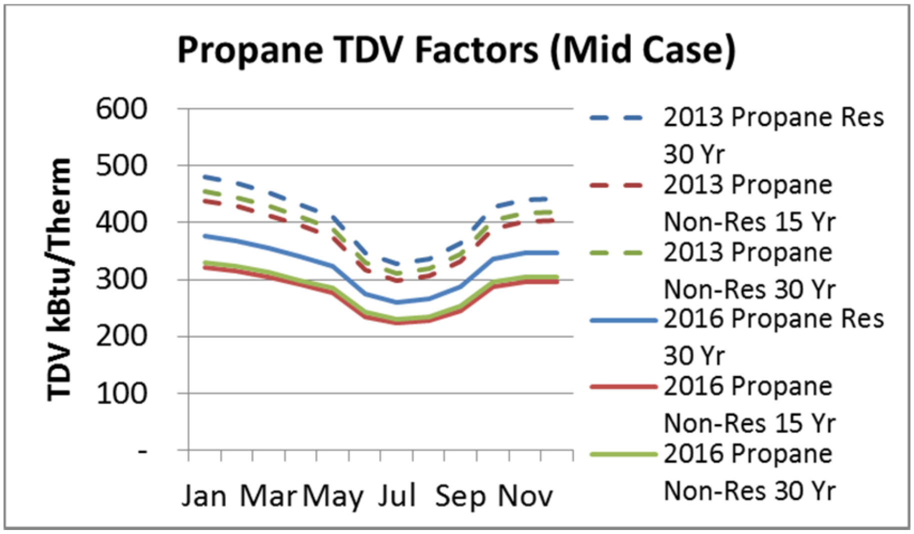
Figure 34. Monthly Variation in Propane Avoided Cost



6.2 Results

A comparison of the 2016 to 2013 Propane TDV Factors is shown in Figure 35. The reduction in natural gas prices results in lower propane TDVs as well for all building types.

Figure 35. Comparison of 2013 and 2016 Propane TDV Factors



Appendix A: Methodology for Creating Weather-Correlated Load Shapes for Use in the TDVs

A.1 Introduction

This appendix describes the statistical methodology used for developing the weather-correlated load shapes, which are used in the production simulation dispatch model to generate hourly market price shapes for the 2016 TDVs.

A.2 Modeling considerations

Modeling a load shape which captures the relationship between historic hourly load and weather data should consider the following:[24]

- Hour-of-day effect. Hourly MW data exhibits an intra-day pattern. The lowest loads tend to occur around 04:00 and the highest 16:00.
- Day-of-week effect. Hourly MW data exhibits an inter-day pattern. Hourly loads tend to be low on weekend days and high on mid-week days.
- Holiday effect. Hourly loads on the day-before, day-of, and day-after a holiday tend be higher than on other days.
- Month-of-year effect. Hourly loads tend to be high in summer months and low in other months. But this may largely be driven by the monthly temperature pattern.

[24] Woo, C.K., P. Hander and N. Toyama (1986) "Estimating Hourly Electric Load with Generalized Least Squares Procedures," The Energy Journal, 7:2, 153-170.

- Weather effect. Hourly loads move with weather. Hot (cold) days, especially after consecutive hot (cold) days, tend to have higher hourly loads than other days.
- Hourly load distribution. Hourly load data has a skewed distribution, with a long right tail. A logarithmic transformation of the load data yields a more symmetric distribution amenable to a regression-based approach to develop a typical weather year load shape.
- Peak loads. While a regression-based approach is useful for predicting hourly loads in a typical weather year, it produces a flatter shape than the one in real world. This is because regression-based predictions tend to gravitate towards the mean MW, rather than the maximum and minimum MW, which are, by definition, the two extreme ends of an hourly load distribution. However, a secondary regression is used to adjust values based on their ranks in a load duration curve.
- Load growth. The typical weather year load shape's maximum MW should match the system peak MW forecast. If the load modeling is done for normalized MW (= hourly MW / annual peak MW), the resulting prediction can then be scaled to match the forecast peak MW.

A.3 Regression-based approach

We use a regression-based approach to develop equations for predicting a normalized MW shape under the TMY weather. Illustrated with an SCE example, the approach has the following steps:

- Step 1: Use hourly observations in the 2003-2007 period (or 2000-2007 for some climate zones) with dry bulb temperature greater than or equal to 75^{o}F in one particular weather station (chosen to be Burbank for SCE) to estimate a linear regression whose dependent variable is $s = ln(S)$ where S = hourly MW / annual peak MW. This step aims to show how hourly MW varies with its fundamental drivers. The explanatory variables are the intercept; dummy variables for month-of-year, day-of-week, hour-of-day; dummy variables for day-before, day-of, and day-after a Federal holiday; and weather variables for some number of relevant stations (four are used in the case of SCE: Fresno, Riverside, Burbank and Long Beach).
    - o Each weather station has two associated sets of variables: one based on the dry bulb temperature, in order to capture effects based solely on temperature, and one based on dew point temperature, in order to capture the added demand for air conditioning on humid days.

- The weather variables are coincident cooling degree hours, coincident heating degree hours, weighted sum of lagged cooling degree days, and weighted sum of lagged heating degree days. The lagged heating and cooling degree days cover a three day span, and are used to represent cold and heat spells respectively.[25]

+ Step 2: Repeat Step 1 for the remaining hourly observations (less than 75°F). The regression resulting from Steps 1 and 2 can be written as:

$$s = \begin{cases} \beta_0 + \sum_{n=1}^{11} \beta_{m,n} m_n + \sum_{n=1}^{6} \beta_{d,n} d_n + \sum_{n=1}^{23} \beta_{h,n} h_n + \sum_{n=-1}^{1} \beta_{f,n} f_n + \sum_{n} \sum_{i=1}^{2} \sum_{j=1}^{4} \beta_{w,i,n,j} w_{n,i,j} + \varepsilon & if\ T_k \geq 75 \\ \eta_0 + \sum_{n=1}^{11} \eta_{m,n} m_n + \sum_{n=1}^{6} \eta_{d,n} d_n + \sum_{n=1}^{23} \eta_{h,n} h_n + \sum_{n=-1}^{1} \eta_{f,n} f_n + \sum_{n} \sum_{i=1}^{2} \sum_{j=1}^{4} \eta_{w,i,n,j} w_{n,i,j} + \varepsilon & if\ T_k < 75 \end{cases}$$

Here, β_0 and η_0 are the intercepts; m, d, and h are the month of year, day of week, and hour of day indicators; f is the federal holiday indicator; and w is the weather variable, which is summed over all weather stations (n), both dry bulb and dew point temperatures (i), and cooling and heating degree hours, as well as lagged cooling and heating degree days (j). T_k is the dry bulb temperature at a single weather station, chosen to be the most influential in the region, and ε is the error.

+ Step 3: Use the regression results from Step 1 and Step 2 to make a preliminary prediction of an hourly normalized MW for a given weather condition: $S_P = \exp(s_P + v^2/2)$, where s_P = predicted value of $ln(S)$ and v^2 = variance of s_P.

+ Step 4: Divide the S_P values from Step 3 into 20 bins, each containing 5% of the sample, based on each value's rank in a load duration curve. For example, bin "1" has S_P values below the 5-percentile, and bin "20" has values above the 95-percentile.

+ Step 5: Run the actual vs. predicted regression:

$$S = \beta_0 + \sum_{n=1}^{19} \beta_{B,n} B_n + \beta_s s_p + \varepsilon$$

Here, β_0 is the intercept, B_n is the bin indicator, s_p is the normalized MW, and ε is the error. This step corrects for the fact that the preliminary prediction S_P may not match actual

[25] Weight = 1/2 for the day before, 1/3 for two days before, and 1/6 for three days before.

normalized MW, especially for bins near the bottom and bins near the top (e.g., $S_P > S$ in bin "1" and $S_P < S$ in "20").

+ Step 6: Compute the final prediction S_F based on the regression result from Step 5. This value is limited to a maximum of 1 so that the annual peak MW value is not exceeded in the next step.
+ Step 7: Make hourly MW prediction = S_F * annual peak MW.

A.4 Results

The results of this regression approach show very good prediction of actual loads. In the examples below, predicted and actual loads are compared for the sample of hourly data in 2007 for the SCE region. Figure 36 shows the predicted and actual load duration curves for 2007. Figure 37 shows the actual and predicted MW for the peak week in 2007. Since the predicted curves closely match the actual ones, the regression-based approach is useful for developing a TMY load shape.

Figure 36. 2007 Load Duration Curve for SCE

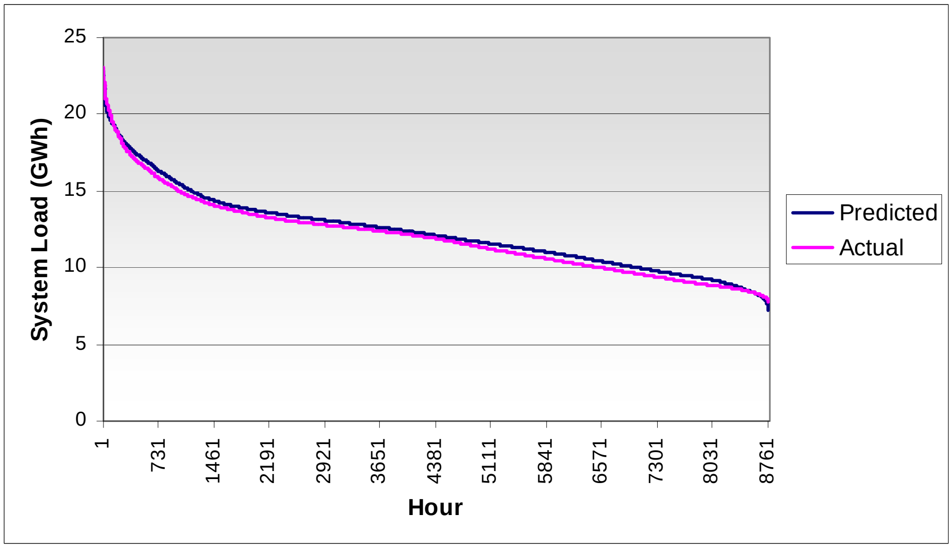
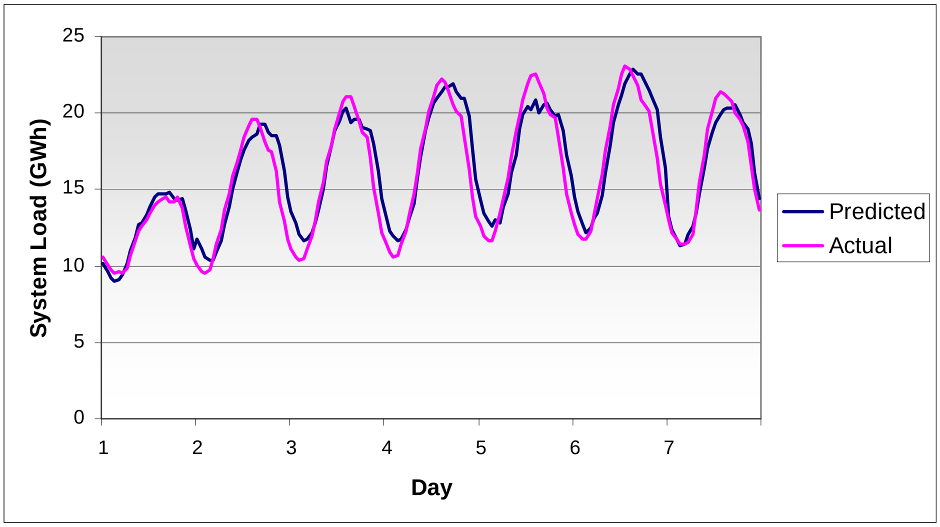


Figure 37. 2007 Peak Load Week for SCE



A.5 Weather Stations used for load shape regressions

The following table shows the utility service territory regions for which revised weather correlated load shapes were developed. The weather station data used in the statistical analysis are shown in the table as well. The weather stations were chosen based on their proximity to well-populated area within each region, and are shown in Table 15 below.

Table 14. Weather Stations Applied to Each Load Region in California

Load Region	Weather Stations Used in Analysis
Anaheim	LOS-ALAMITOS_722975
Burbank	BURBANK-GLENDALE_722880
CFE	IMPERIAL-BEACH_722909
Glendale	BURBANK-GLENDALE_722880
IID	IMPERIAL_747185
LADWP	LONG-BEACH_722970 BURBANK-GLENDALE_722880
MID	MODESTO_724926
NCPA	SACRAMENTO-METRO_724839
Pasadena	BURBANK-GLENDALE_722880
PG&E NP15	FRESNO_723890 SACRAMENTO-EXECUTIVE_724830 SAN-JOSE-INTL_724945 SAN-FRANCISCO-INTL_724940 UKIAH_725905
PG&E ZP26	FRESNO_723890 BAKERSFIELD_723840
Redding	REDDING_725920
Riverside	RIVERSIDE_722869
SCE	FRESNO_723890 LONG-BEACH_722970 RIVERSIDE_722869 BURBANK-GLENDALE_722880
SDG&E	SAN-DIEGO-LINDBERGH_722900 SAN-DIEGO-MONTGOMER_722903 SAN-DIEGO-GILLESPIE_722907
SMUD	SACRAMENTO-EXECUTIVE_724830
SVP	SAN JOSE-INTL_724945
TID	MODESTO_724926