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Time Dependent Valuation of Energy for Developing Building Efficiency Standards

2019 Time Dependent Valuation (TDV) Data Sources and Inputs

July 2016

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 2019 Time Dependent Valuation (TDV) update for the Title 24 building standards. It reflects the TDV values included in the excel file named “TDV_2019 Update_6_30.xls”

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1 Background and Approach

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 and 2019 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 2019 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, 2013, and 2016 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 2019 Title 24 Building Energy Efficiency Standard TDVs, like those developed for the 2008, 2013, 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 2019 TDVs spans the years 2020 to 2049 for the 30-year analysis and 2020 to 2034 for the 15-year analysis. TDV NPV costs are reported in 2020 dollars, and are formatted to the 2009 calendar year and TMY weather year file data.

In prior analyses in 2013 and 2016, the majority of the input assumptions were taken from the latest Integrated Energy Policy Report (IEPR) and associated planning documents. In order to represent the latest energy policies, the 2019 update includes expanded input assumptions for the electric TDVs to additionally reflect the recent passing of SB 350, which includes a target of a 50% renewable portfolio standard (RPS) and a doubling of energy efficiency by 2050.

Table 1. SB 350 Considerations in Base Case Scenario for Electric TDVs

Input	Description
Load Forecast	2015 IEPR Mid Case, including mid-case electric vehicle and mid-case CO_2 price forecasts.
Renewable Portfolio Standard (RPS)	Assume California meets a 50% RPS by 2030 using predominantly in-state resources.
Energy Efficiency	Assumed a doubling of the 2015 IEPR Additional Achievable Energy Efficiency Mid Case by 2030.[1] The rate of doubling was assumed internally at the CEC and is documented in Table 3.
Diablo Canyon Nuclear Facility	Assumed to retire in 2024
Retail rate escalation	Electric retail rates were determined using the CPUC RPS calculator using consistent input assumptions for 50% RPS and energy efficiency. This approach is further documented in Section 3.1.8.

In addition to a Base Case scenario, we evaluated two additional sensitivities as no implementation plans for SB 350 have been completed, which are detailed in Table 2.

Table 2. SB 350 Sensitivities

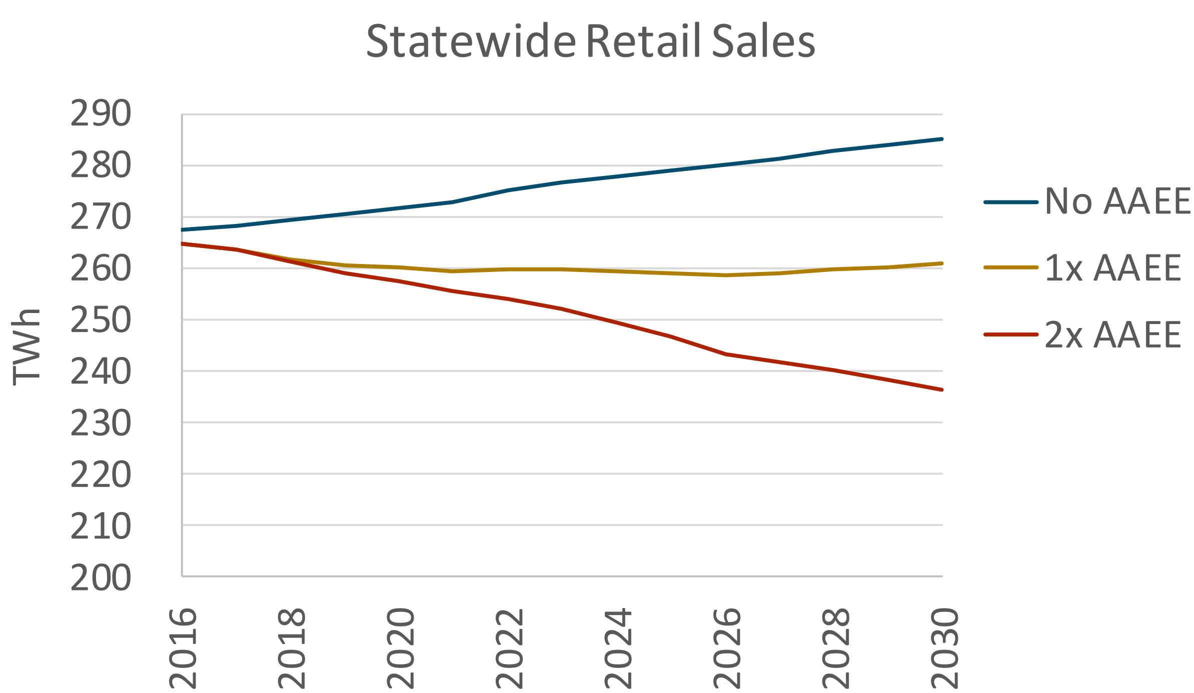
	Load Forecast	Energy Efficiency	CO2 Price
Base Case	***2015 IEPR Mid-demand***	***2x 2015 IEPR AAEE***	***2015 IEPR Mid Case***
High Electrification/Low Energy Efficiency		***1x 2015 IEPR AAEE***	
High CO_2 price			***2015 IEPR High Case***

The 2015 Integrated Energy Policy Report (IEPR) adopted load forecast is based on the California Energy Demand 2016-2026 Final Forecast (2015 CED) (Figure 1).[2] The 2015 CED includes three

[1] California Energy Demand 2016-2026 Final Forecast. January 2016. CEC-200-2016-001-VI
[2] The 2015 IEPR adopted forecast is available at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03

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 2015 CED.

Figure 1. 2015 IEPR Mid Demand Load Forecast



The doubling of AAEE shown in Figure 1 was assumed internally at the CEC using the factors shown in Table 3. The 2015 IEPR projects AAEE through 2026, so the CEC assumed a 3% annual increase in projected energy efficiency from 2027 through 2030.

Table 3. CEC multiplier assumed to achieve SB 350 doubling of AAEE by 2030

2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	1	1.077	1.154	1.231	1.308	1.385	1.462	1.538	1.615	1.692	1.769	1.846	1.923	2

1.3 Overview of Avoided Costs

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.

1.3.1 OVERVIEW OF AVOIDED COSTS OF ELECTRICITY

For each climate zone, the avoided cost of electricity is calculated as the sum of seven components, each of which is summarized in Table 4.

Table 4. Components of Time Dependent Valuation for Electricity

	Component	Description
Marginal Energy Avoided Costs	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
	System Losses	The costs associated with additional electricity generation to cover system losses
	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).
Retail Rate Adder		The six components above are scaled to match the average retail rate through the retail rate adder.

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 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 5 summarizes the methodology applied to each component to develop the hourly price shapes.

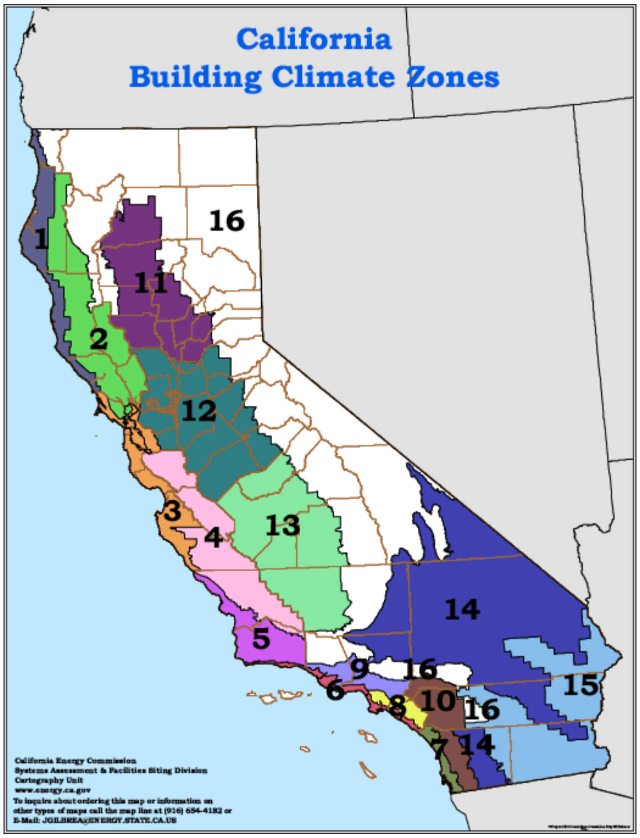
Table 5. Summary of methodology for electric TDV component forecasts

Component	Basis of Annual Forecast	Basis of Hourly Shape
Generation Energy	IEPR Production Simulation Results for 2016-2026, 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 a regression hourly temperature data and distribution feeder load data
Greenhouse Gas	2015 IEPR	Directly linked with energy shape

Emissions		based on implied heat rate of marginal generation, with bounds on the maximum and minimum hourly value
RPS Adder	Premium for renewable generation calculated using levelized renewable costs from CPUC RPS Calculator	Constant allocation factor, does not vary by hour
Retail Rates	E3 estimates from the RPS calculator for consistency with a 50% RPS	Constant allocation factor, does not vary by hour

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 2 is a map of the Title 24 climate zones in California.

Figure 2. California Climate Zones used in Building Code Standards



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

Most of the components of avoided costs in the 2019 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. 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 is consistent with the 2016 TDV methodology.

E3 uses a 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 is 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 and 2019 TDVs, the large differences between the climate zones seen in 2013 have been reduced.

1.3.2 OVERVIEW OF AVOIDED COSTS OF 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. The components are:

+ Retail price forecast
+ Wholesale commodity price forecast
+ Emissions Costs
+ Distribution costs

1.3.3 OVERVIEW OF AVOIDED COSTS OF PROPANE

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

+ Retail Cost
+ Emissions Costs

1.4 TDV Frequently Asked Questions

1. What is Time Dependent Valuation (TDV)?
    - TDV is the cost-effectiveness and energy valuation methodology used in development and implementation of the Title 24 Building code. The TDV of energy is a participant cost effectiveness metric to evaluate whether a Title 24 measure will save consumers money on their utility bill over the life of a new building. The values of TDV are constructed from a long term forecast of hourly electricity, natural gas and propane costs to building owners consistent with the latest CEC forecasts and outlook for California's energy sectors. The time dependent nature of TDV reflects the underlying marginal cost of producing and delivering an additional unit of energy, similar to a time of use retail tariff, and the resulting economic signal aligns energy savings in buildings with the cost of producing and delivering energy to consumers.
2. How is TDV used?
    - The Energy Commission uses TDV in its California Building Energy Code Compliance software to set the target energy budgets for newly constructed buildings, and to value the design trade-offs made during the development and construction of those buildings. The TDV metric determines (in part) the long term cost effectiveness of proposed energy efficiency measures. TDV is the metric adopted in the Integrated Energy Policy Report for the measurement of zero net energy (ZNE) buildings.
3. Why is TDV biased in favor of natural gas for space and water heating?

- TDV is a participant cost effectiveness metric. TDV is not biased in favor of natural gas and it does not "punish" electric space and water heating, it simply reflects their cost effectiveness relative to other options.

4. Why doesn't the Energy Commission focus on greenhouse gas emissions reductions instead of the TDV of energy cost effectiveness?

    - The Warren-Alquist Act (the Act) established the Energy Commission in 1974, and governs the work of the Energy Commission. The Energy Commission has seven core responsibilities. One of those responsibilities is to promote energy efficiency and conservation. The Act requires the Energy Commission to adopt cost effective building energy efficiency standards. The cost effectiveness requirement of the Act has allowed the Energy Commission to be aggressive in developing energy efficiency standards for buildings while ensuring those regulations do not become fiscally burdensome to Californians.

5. Why does TDV use statewide average electricity and natural gas retail rate levels instead of actual retail rate structures that are in place?

    - The TDV uses statewide average retail rate levels for electricity, natural gas, and propane in order to keep similar stringency and common construction practices statewide (with some variations due to climate). The overall stringency of the code is set based on a project of future retail energy prices and using a statewide average results in uniform stringency of the standard.

6. Why is the Time Dependent variation set based on marginal costs?

    - By using the underlying system marginal costs the TDVs reflect a "perfect" marginal cost of service. This means that the economic signal to save energy is aligned with the times that saving that energy is most valuable. We recognize that there are a number of different retail pricing structures in the state for electricity, natural gas, and propane that reflect underlying marginal costs to differing degrees. The approach of using a marginal cost basis reflects a long term trend toward retail rates that reflect the marginal cost of service and keeps the building energy efficiency code relatively stable over time while also providing the greatest underlying value to the energy system.

7. Why are TDV units in kBTU/kWh and kBTU/therm if they measure cost effectiveness?

    - TDV are calculated in life cycle dollars per unit of energy for each hour and climate zone in California. For the purposes of building code compliance they are converted to units of kBTU/kWh and kBTU/therm using fixed multipliers. This is done because of a long standing precedent of using ‘source energy’ factors in building code analysis, which is familiar with many practioners. In addition, conversion to energy units prevents confusion between a long term estimate of consumer bill savings based on a California average over 30 years and specific customer bill savings in a specific year and location.

8. Why doesn't the Energy Commission adjust TDV to reflect the cost effectiveness of technology "x" or this aspect of technology "y"?

    - The TDV metric are simply a reflection of price forecasts of energy in California and applicable across the range of most measures evaluated in the Building Energy Code. They should not be manipulated to address the unique issues regarding every possible technology. TDV savings is only one aspect of estimating the cost effectiveness of any Standards measure. Any unique aspects of a given technology should be considered when conducting a larger analysis of the technology as part of an effort to integrate that technology into the Standards.

2 Updates to 2019 TDV Methodology

This section summarizes the key changes to the 2019 TDV methodology compared to the 2016 approach. One notable change has been made to the TDVs based on new data available for allocating costs for electric transmission and distribution. For other components of the electric TDVs and for all components of the natural gas and propane TDVs, the 2019 methodology represents refinements and improvements to the 2016 methodology but does not include any major departures from the prior approach.

2.1 Electricity Transmission and distribution updated methodology

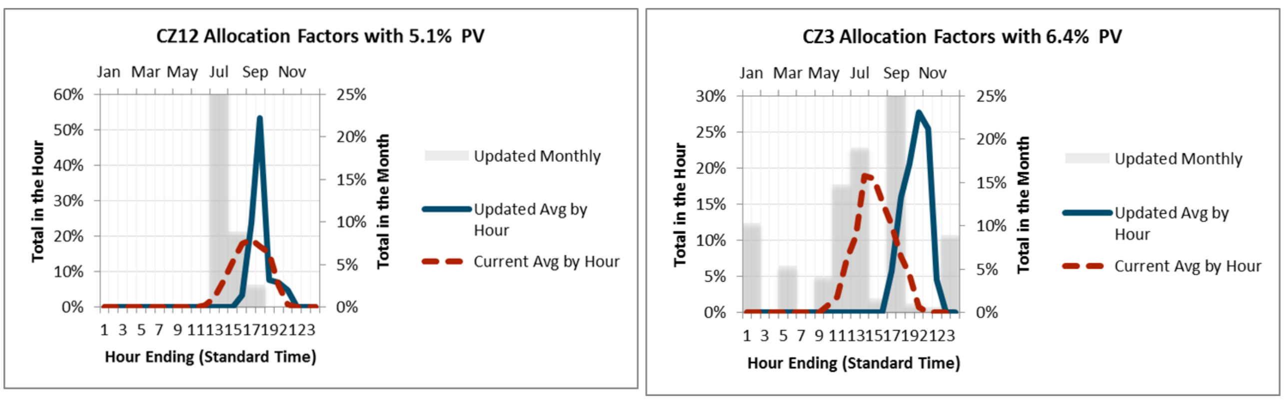
In the 2016 TDVs, avoided electric transmission and distribution (T&D) costs were allocated to hours throughout the year based on a temperature proxy. For 2019, we are introducing an improved methodology for T&D avoded cost allocation that is based on actual distribution load data in addition to temperature. The new methodology allows the TDVs to more accurately reflect usage patterns in each climate zone, as well as reflect the impact of local solar PV on T&D peak demand.

The new methodology uses regression analyses to forecast distribution hourly loads for each climate zone under the weather conditions used for the building energy use simulations. In addition to dry-bulb temperature, the regression analyses use variable such as cooling degree hours, lag variables, moving averages, cross produce terms, and dummy variables to generate predictive models with R-squared values around 90%.

The 2019 TDV analysis is utilizing the same regression models developed for the recent CPUC avoided cost update, and full documentation of those models can be found therein.[3]

Figure 3 shows the updated and existing T&D allocation factors for climate zones 12 and 3 (Sacramento, and Oakland). The red dashed lines are the total current allocation weights assigned to each hour of the day (Hour Ending, Pacific Standard Time). The blue lines are the same allocation totals for the updated factors in 2020. In addition to showing total allocation weights by hour of the day, the figures also show the distribution of updated allocation weights by month (the gray bars, corresponding to the upper and right axes).

Figure 3. Updated T&D Cost Allocation for 2020 compared to Current Factors



As mentioned above, the updated allocation factors shown in the figures are for 2020. The updated allocation factors vary by year because of the impact of increasing solar PV installations in the climate zones. In 2020, climate zone 12 is modeled with 5.1% of the area's energy needs met by solar PV installed since 2010, and climate zone 3 is based on 6.4% solar PV since 2010. The PV values are incremental to 2010 because that is the year of the utility load data used as the basis for the simulated area loads. The additional PV output is subtracted from the simulated loads to estimate the adjusted net loads for the climate zone.

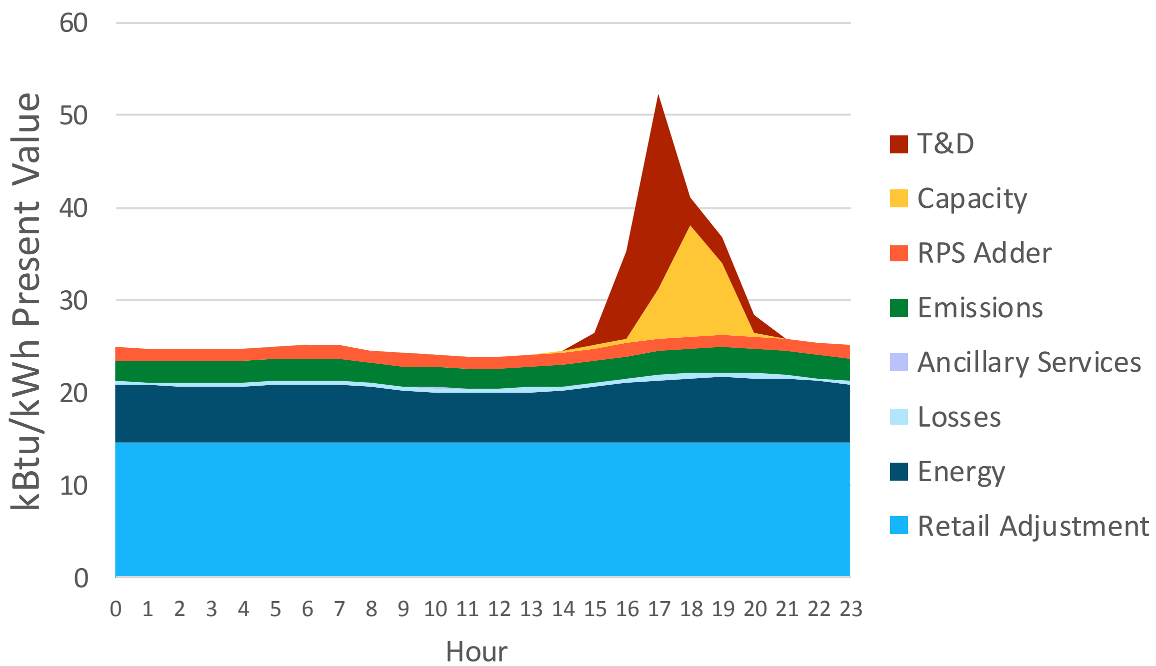
[3] The transmission and distribution cost allocation regressions are documented further in the CPUC Avoided Costs June 2016 Interim Update, online: http://www.energydataweb.com/cpuc/search.aspx?did=1549

3 Updates to 2019 TDV Inputs

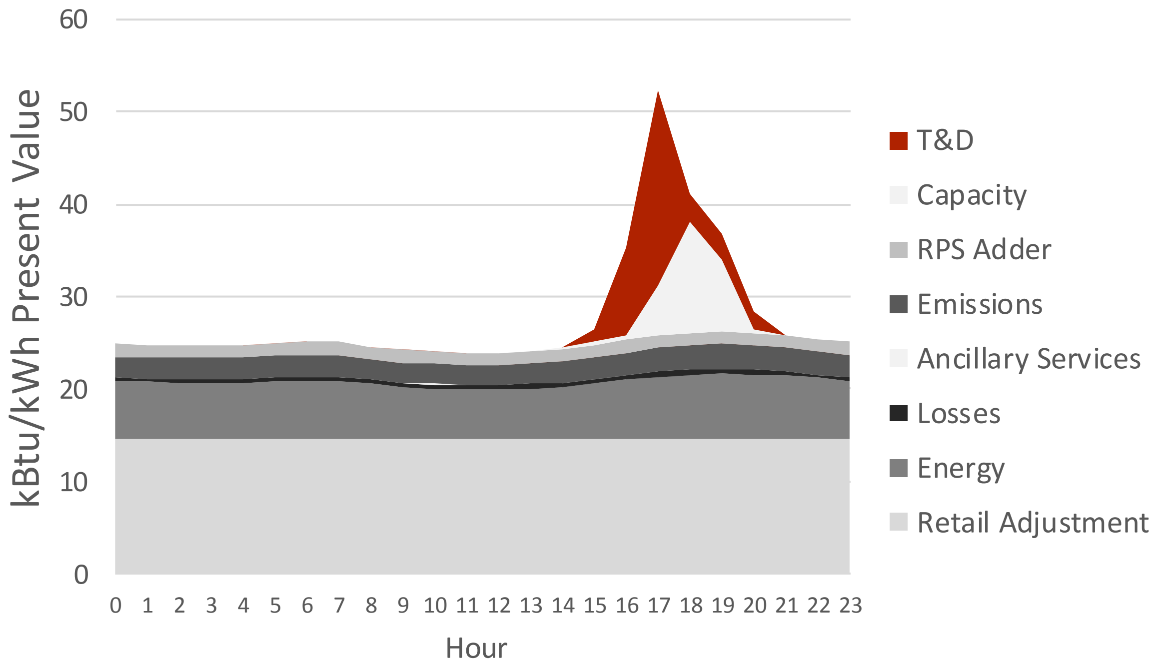
In this section we will walk through each component of the 2019 TDVs and document associated updated inputs for electricity, natural gas, and propane.

3.1 Updates to Electricity TDV Inputs

Figure 4. Sample TDV shape by component, Average day, levelized 30-year residential, CZ12



3.1.1 TRANSMISSION AND DISTRIBUTION CAPACITY AVOIDED COSTS



Transmission and distribution avoided costs are calculated using the weighted average from the latest utility general rate cases (GRCs). For the 2019 cycle, we have updated these costs to reflect the PG&E 2014 GRC, SCE 2015 GRC, and SDG&E 2015 GRC.[4] The results are shown in Table 7.

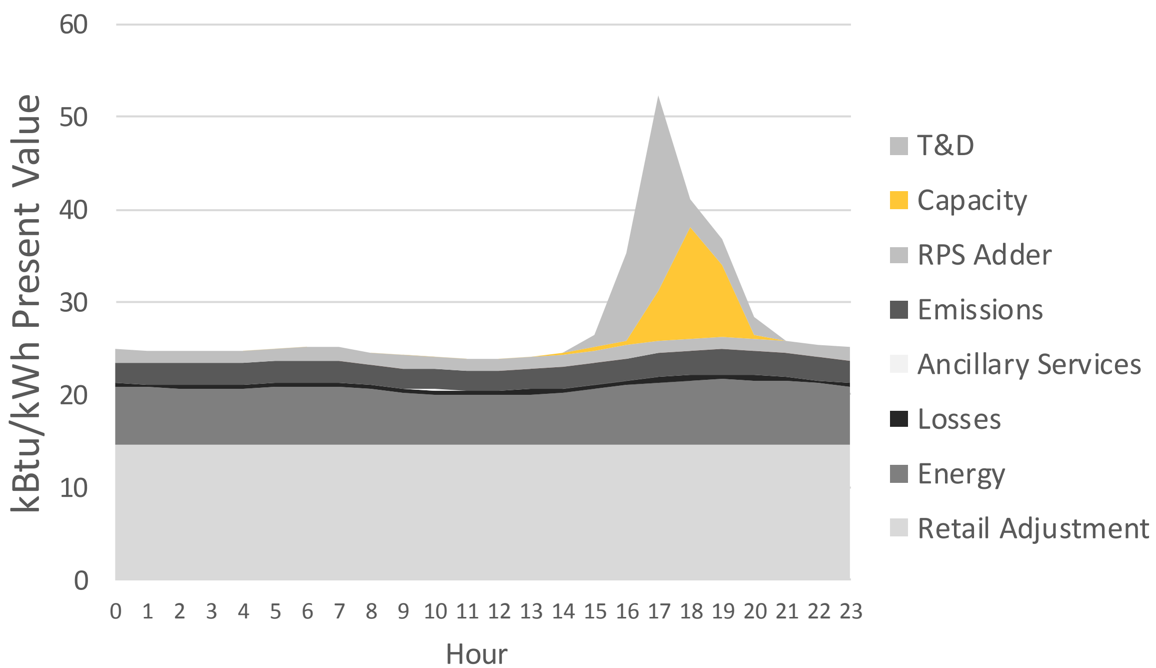
Table 7. Weighted average of avoided T&D Costs for 2019 TDVs

	Statewide Avoided Costs [$/kW]
Transmission	$33.63
Distribution	$83.99

[4] PGE: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M099/K767/99767963.PDF
SCE: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M155/K034/155034804.PDF
SDG&E: https://www.sdge.com/sites/default/files/regulatory/Saxe%20Clean%20w_Attachments.pdf

These avoided costs are allocated to hours and climate zones using the new methodology of actual utility distribution loads and behind-the-meter PV forecasts. This replaces the temperature-only regression used in 2016 and therefore shifts the peak allocation to hours later in the evening. This methodology is documented further in Section 2.1.

3.1.2 GENERATION CAPACITY AVOIDED COSTS



The generation capacity value captures the cost of maintaining a generator fleet with enough capacity to meet each year's peak loads. Two key assumptions were updated as a part of the 2019 TDVs: the resource balance year (RBY) and capacity value allocation.

Capacity value is calculated as the the cost of a combustion turbine (CT) less the margins that the CT could earn from the energy markets. 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). These are the same assumptions used in the 2016 TDV analysis. A comparison of the cost and performance assumptions for the two technologies is shown in Table 8.

Table 8. 2015 CEC Cost of Generation Report Performance and Cost Assumptions ($2013)

Metric	Advanced CT (LMS100)	Notes
Heat rate (Btu/kWh)	9,880	Table 49
Financial Life (yrs)	20	Table 14
Installed Cost ($/kW)	$1,305	Table 51, Merchant
Fixed O&M ($/kW-yr)	$23.87	Table 57, $2013
Variable O&M ($/MWh)	0	Table 58, $2013

Table 9. Financing Assumptions

	CEC COG Report
Financial Life (Yrs)	20
Debt-to-Equity Ratio	45%
Debt Cost	5.3%
Equity Cost	10.04%

The resource balance year represents the next year in the future that additional capacity needs to be built to meet peak system demand and 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 capacity value transition from short-run to long-run time scales; after this point, 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 capacity.

Figure 5. Resource Balance Year assumed based on modeled California load and available capacity resources

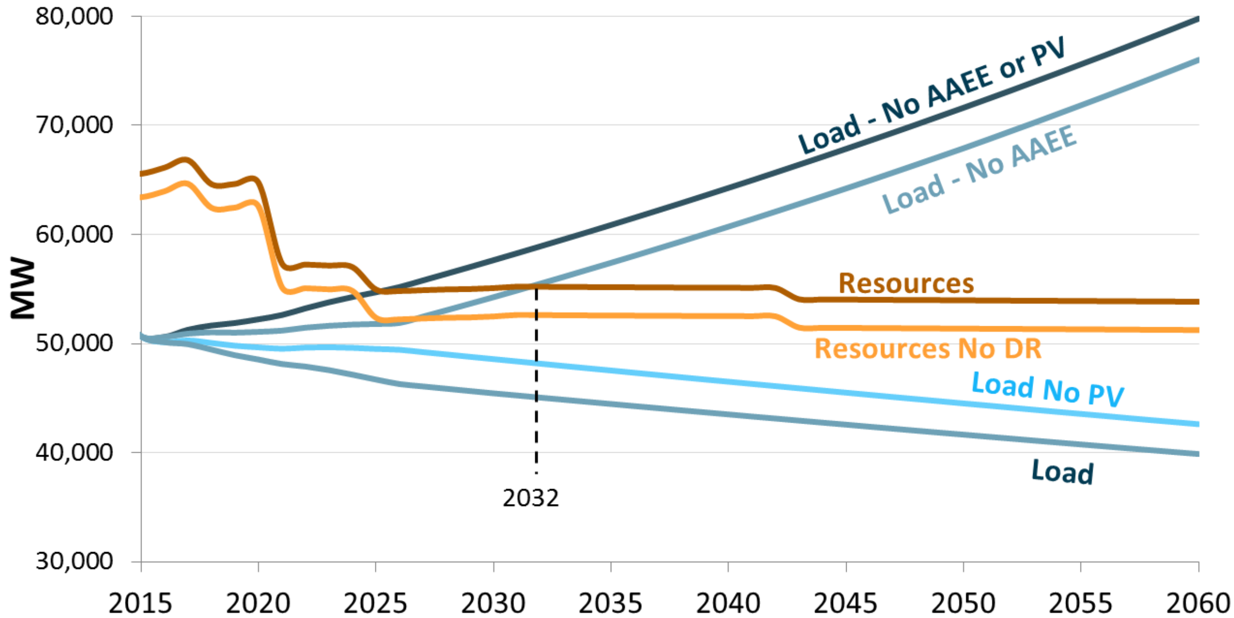
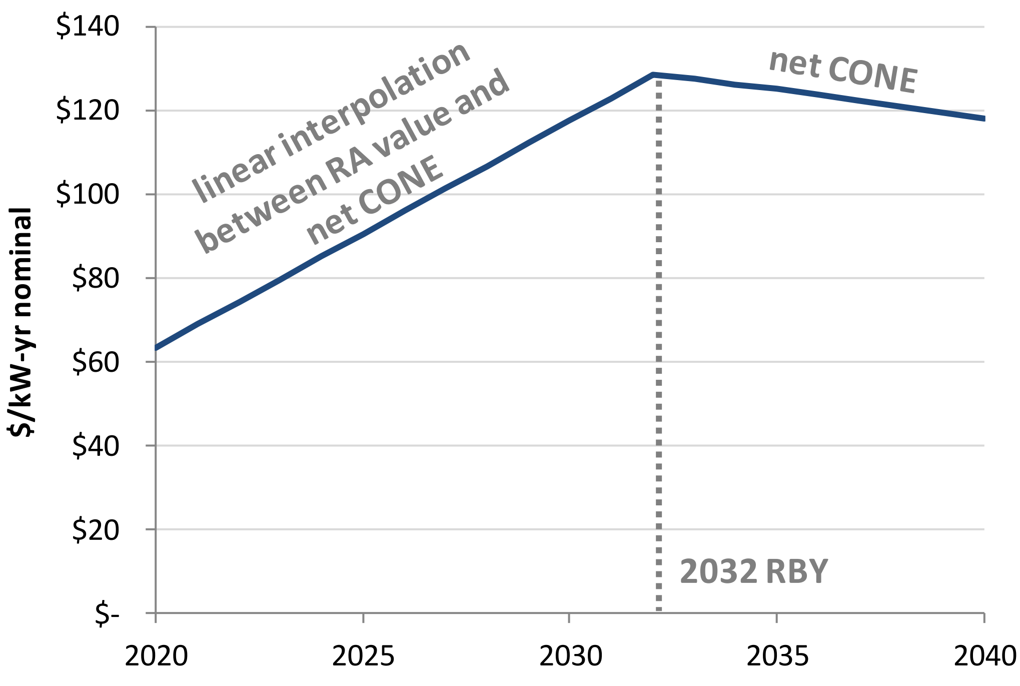


Figure 6. Capacity Value Forecast



We additionally updated the capacity value allocation through new runs of the RECAP model using a 50% RPS assumption. In the 2019 TDVs, avoided electric generation capacity costs are allocated based on Loss-of-Load-Probability (LOLP). The E3 RECAP model[5] estimates LOLP for each month/hour/day-type combination during the year based on net load (gross load net of non-dispatchable resources, i.e. renewables, nuclear, and hydro) and available dispatchable generation (i.e. natural gas plants). These values directly express the likelihood of lost load, and therefore give a more accurate relative weighting among hours.

Figure 7. LOLP Tables for 2030

Weekday

Month/Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	2E-18	0	0	0	0	0
9	0	0	0	0	0	0	3E-18	0	1E-17	0	0	0
10	0	0	0	0	0	0	4E-17	0	1E-18	0	0	0
11	0	0	0	0	0	0	6E-16	0	1E-14	0	0	0
12	0	0	0	0	0	0	9E-12	0	2E-12	0	0	0
13	0	0	0	0	0	0	4E-11	1E-15	1E-10	0	0	0
14	0	0	0	0	0	0	1E-09	2E-11	3E-08	0	0	0
15	0	0	0	0	0	3E-18	1E-07	7E-07	8E-06	0	0	0
16	0	0	0	0	5E-19	1E-12	2E-06	2E-05	6E-05	8E-14	0	0
17	0	0	0	0	2E-13	3E-11	2E-05	6E-05	0.0001	1E-05	0	7E-17
18	5E-13	0	0	0	1E-12	9E-08	0.0001	0.0006	0.0053	3E-05	2E-12	2E-08
19	0	0	0	0	5E-08	7E-05	0.0019	0.0049	0.0071	8E-05	1E-13	8E-11
20	0	0	0	6E-14	5E-07	8E-05	0.0024	0.0038	0.0024	5E-07	3E-14	3E-11
21	0	0	0	0	5E-11	9E-08	0.0001	0.0001	6E-05	0	0	6E-14
22	0	0	0	0	0	3E-14	2E-09	4E-10	1E-08	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0

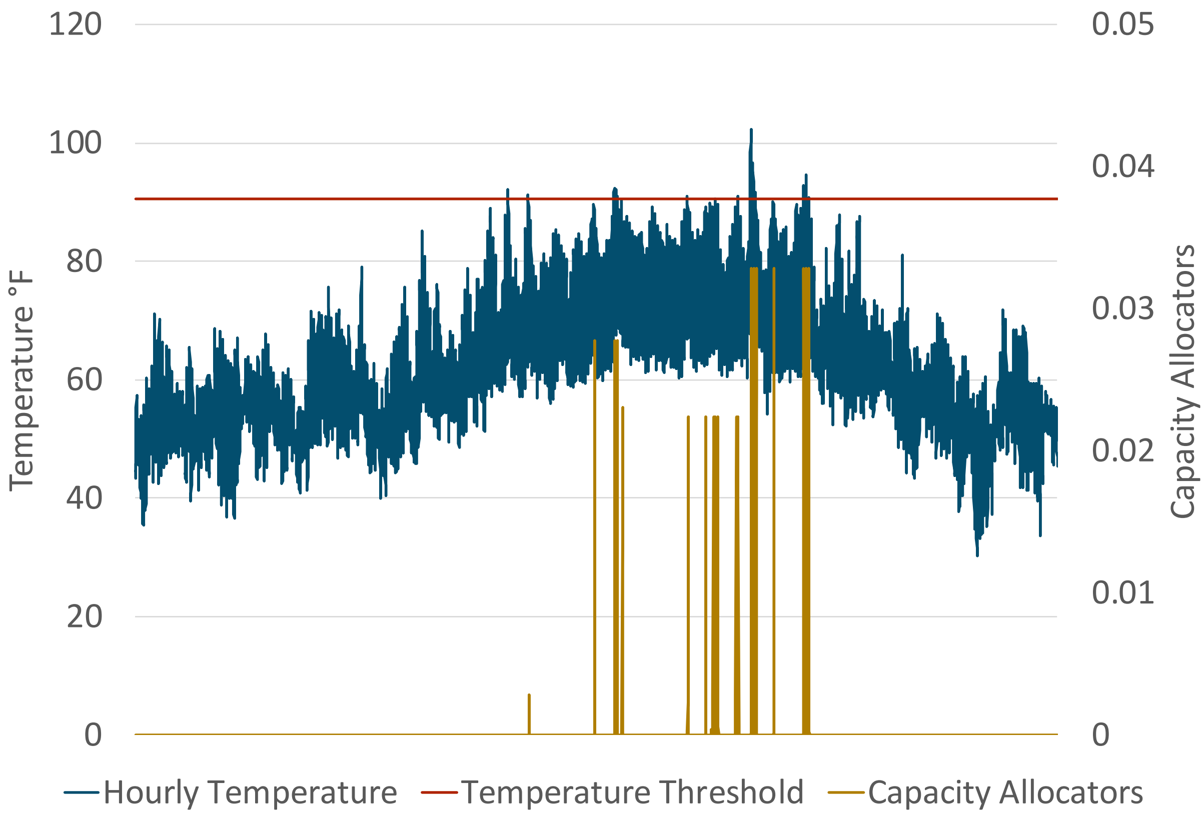
Weekend

Month/Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	1.4E-18	0	2.9E-16	0	0	0
12	0	0	0	0	0	0	1.6E-11	0	1.6E-12	0	0	0
13	0	0	0	0	0	0	1.7E-11	0	1.3E-10	0	0	0
14	0	0	0	0	0	0	4.7E-12	0	1.3E-09	0	0	0
15	0	0	0	0	0	0	5E-10	7.5E-14	4.1E-07	0	0	0
16	0	0	0	0	0	0	8.6E-09	1.6E-10	3.9E-06	0	0	0
17	0	0	0	0	0	2.4E-18	4.3E-07	5E-09	1.3E-05	3.1E-10	0	0
18	8.5E-13	0	0	0	0	1.6E-12	3E-06	8.9E-07	0.00473	7.2E-10	1E-12	7E-13
19	0	0	0	0	8E-13	5.3E-08	0.00133	1.2E-05	0.00675	3.7E-09	4.4E-13	2.6E-14
20	0	0	0	0	2.5E-11	6.3E-08	0.00188	2.1E-05	0.00382	9.5E-12	0	0
21	0	0	0	0	0	4.9E-12	0.00024	6.7E-08	5.5E-06	0	0	0
22	0	0	0	0	0	0	1.6E-07	3.3E-14	3.6E-11	0	0	0
23	0	0	0	0	0	0	4.6E-17	0	0	0	0	0
24	0	0	0	0	0	0	0	0	0	0	0	0

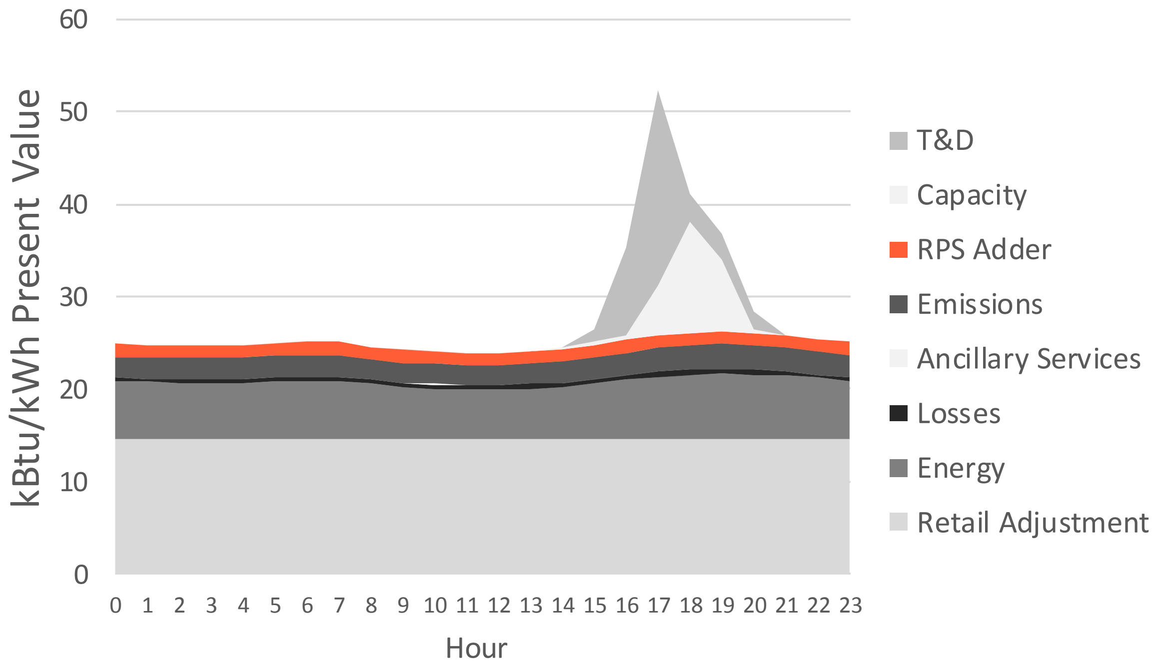
[5] https://ethree.com/public_projects/recap.php

Once an LOLP value is established for each month/hour/day-type using RECAP, these values are allocated to the specific TDV weather year using a 90.5° F threshold. For all days with a statewide loadweighted maximum temperature above 90.5° F, these days receive a capacity allocation in proportion to the LOLP weighting for that particular month/hour/day-type.

Figure 8. Hourly Capacity Allocation



3.1.3 AVOIDED RPS PROCUREMENT COSTS



An additional benefit of electricity usage reduction is the avoided cost of renewable purchases. Because of California's commitment to reach a RPS portfolio of 50% of total retail sales by 2030, any reductions to total retail sales will result in an additional benefit by reducing the absolute quantity of 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 10.

Table 10. 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

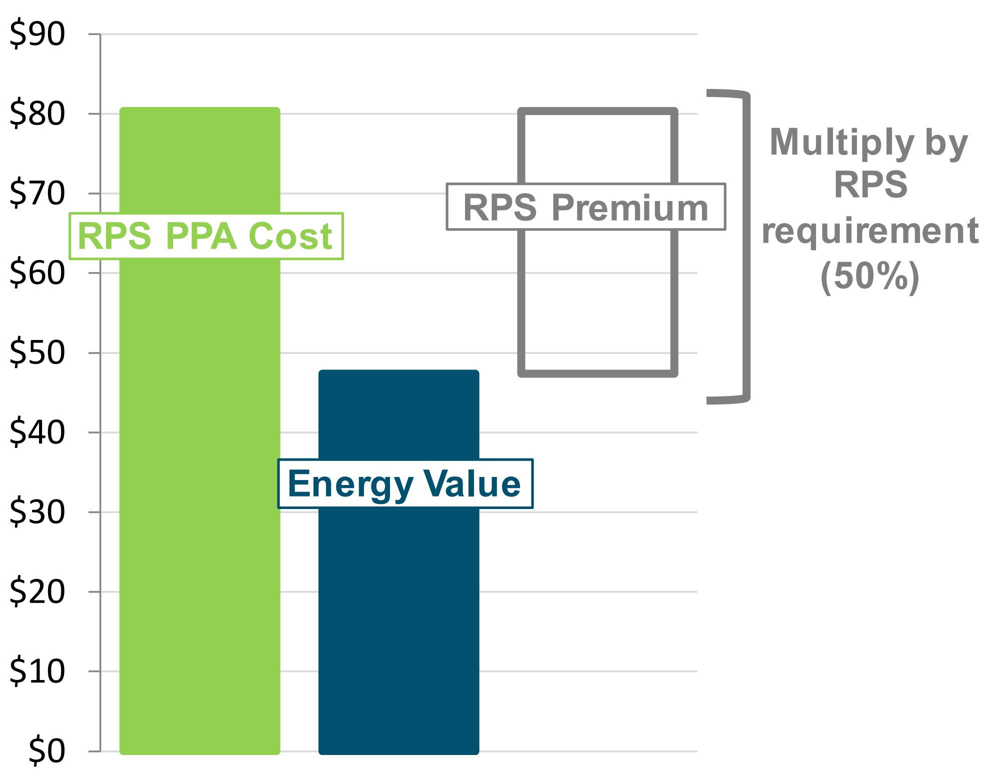
The RPS Adder captures the value that a reduction in load brings to ratepayers through a reduction in required procurement to comply with the state's Renewable Portfolio Standard. Because the state's current RPS policy requires each utility procure renewable generation equivalent to 50% of its retail sales in 2030, each 1 MWh reduction in load in 2050 reduces a utility's compliance obligation by 0.5 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 (Figure 10**Error! Reference source not found.**).

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 minus the energy value provided by that resource. It is important to note that we assume the RPS resource is not fully-deliverable, but rather an energy only resource which means we do not include additional transmission costs on top of the PPA cost and also do not assume any capacity value benefit on top of the energy value.

Figure 9. Components of the RPS Premium

	PPA Price
-	Energy Value$_y$
=	RPS Premium$_y$

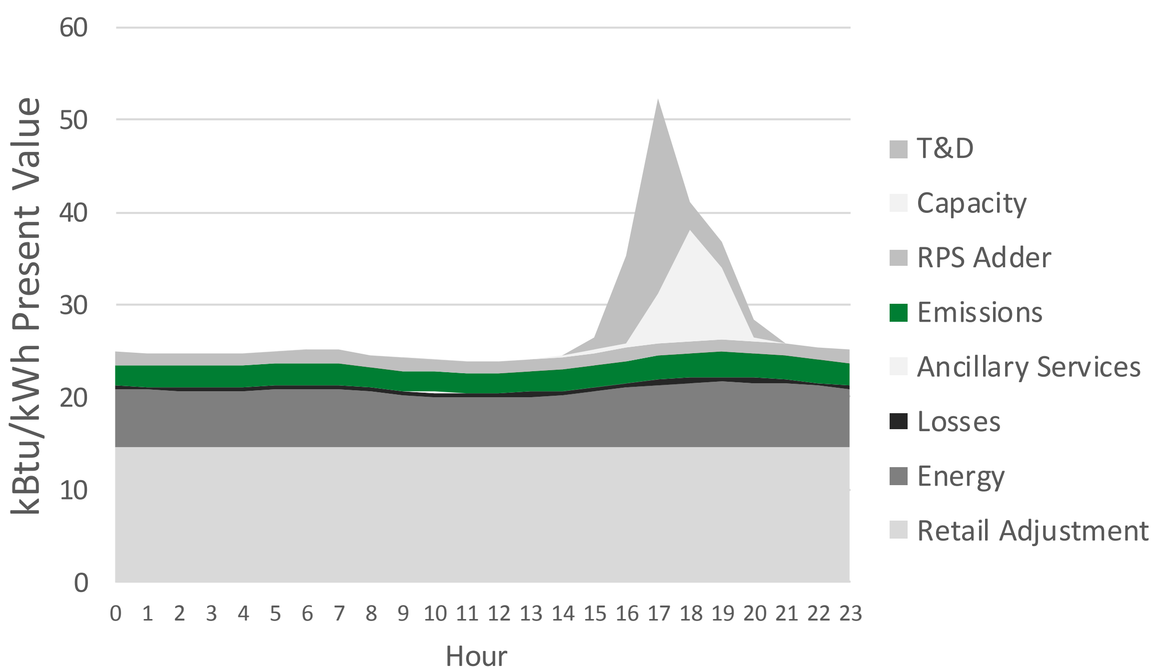
Figure 10. Illustration of RPS Premium for 50% RPS



For this analysis, E3 has assumed that the marginal renewable resource is tracking solar PV (energy-only), 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 RPS Calculator 2020 Solar PV Tracking (> 20 MW). This value is $80.34/MWh levelized.
- The **Energy Value** associated with solar PV is calculated endogenously in the avoided cost model based on the hourly PV production profile from the CPUC RPS Calculator and the hourly cost of energy in each year.

3.1.4 AVOIDED EMISSIONS COSTS



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.

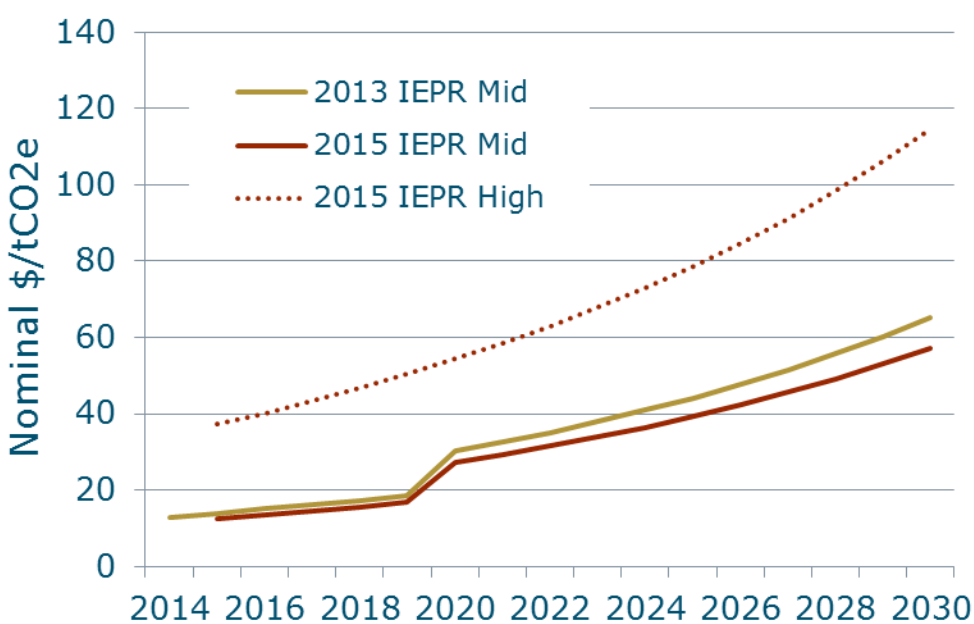
There is a direct link between higher market prices and higher emissions rates since higher market prices enable lower-efficiency generators to operate, resulting in increased rates of emissions at the margin. Of course, this relationship holds for a reasonable range of prices but breaks down when prices 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

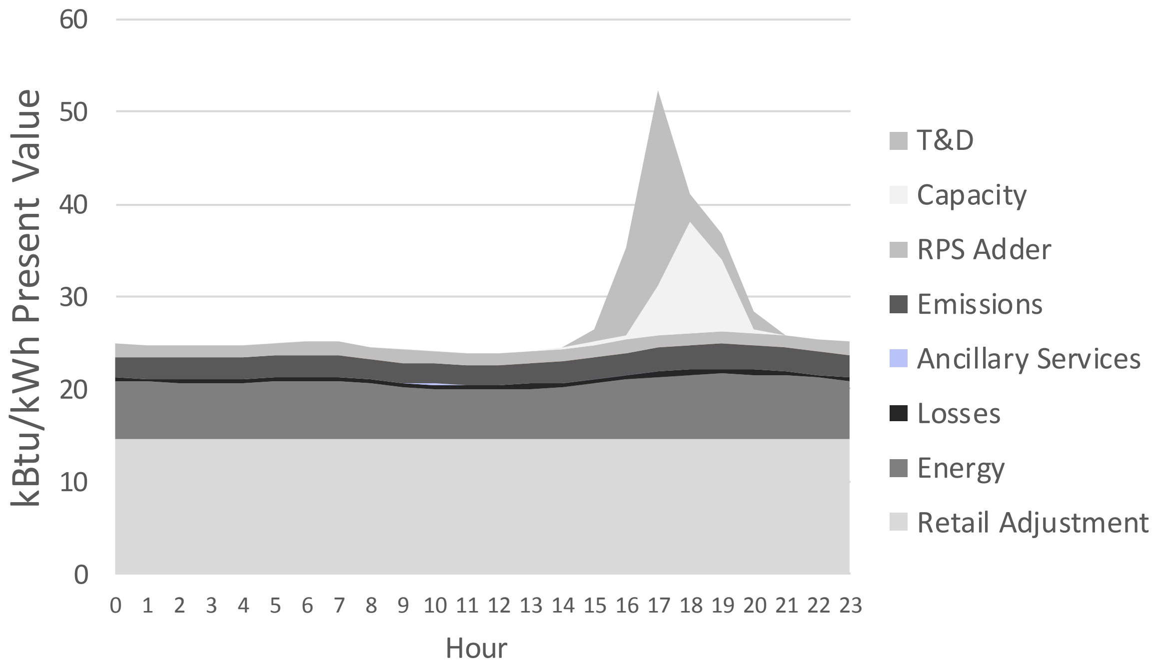
	Proxy Low Efficiency Plant	Proxy High Efficiency Plant
Heat Rate (Btu/kWh)	12,500	6,900
Emissions Rate (tons/MWh)	0.731	0.404

The CO2 emissions price forecast was taken from the 2015 IEPR, which projects nominal CO2 prices from 2020-2030, we then extrapolate to 2049 using a linear trend. We compare the projections from the 2015 and 2013 IEPRs in Figure 11.

Figure 11. CO2 Price Forecasts from 2015 and 2013 IEPR

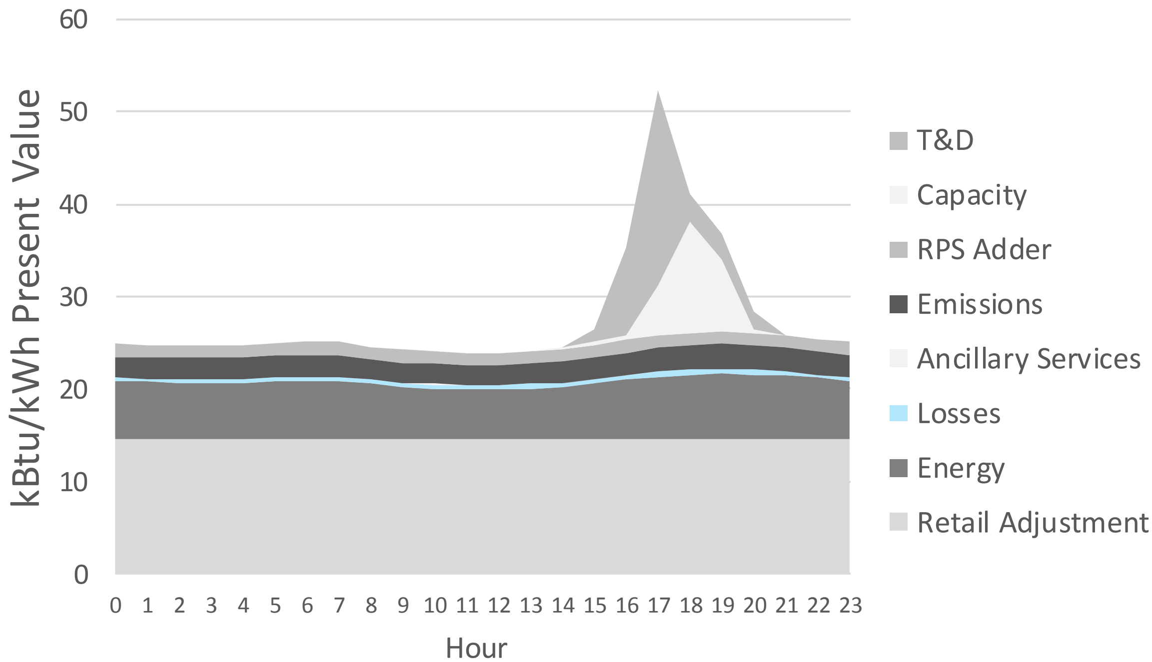


3.1.5 AVOIDED ANCILLARY SERVICES COSTS



The value of avoided ancillary services (A/S) 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 0.5% of the energy value in each year. The multiplier for the 2016 TDVs was 1% of the energy value. 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.

3.1.6 AVOIDED COSTS OF ELECTRIC LOSSES

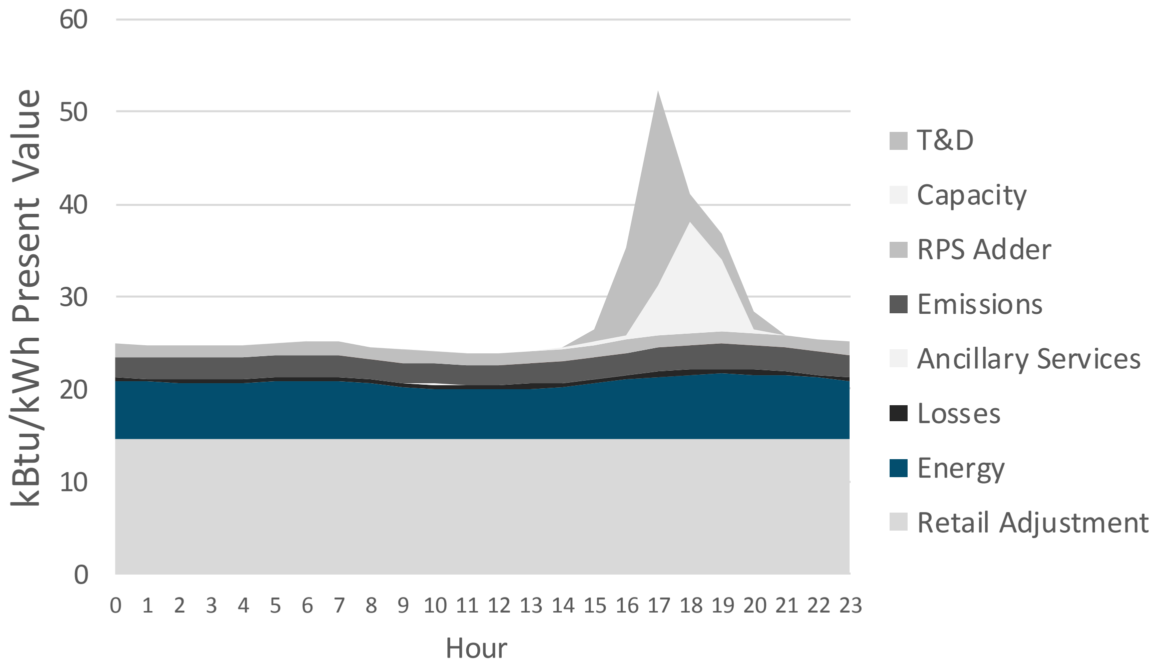


The utility-specific loss factors have been retained from 2013 and 2016 TDV analyses, and are shown in Table 12.

Table 12. Electric loss factors by utility and season

Description	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	0.000	0.000	1.083
Winter Shoulder	1.090	1.077	1.076
Winter Off-Peak	1.061	1.070	1.068
Generation Peak	1.109	1.084	1.081
Transmission Peak	1.083	1.054	1.071
Distribution Peak	1.048	1.022	1.043

3.1.7 AVOIDED COSTS OF ENERGY

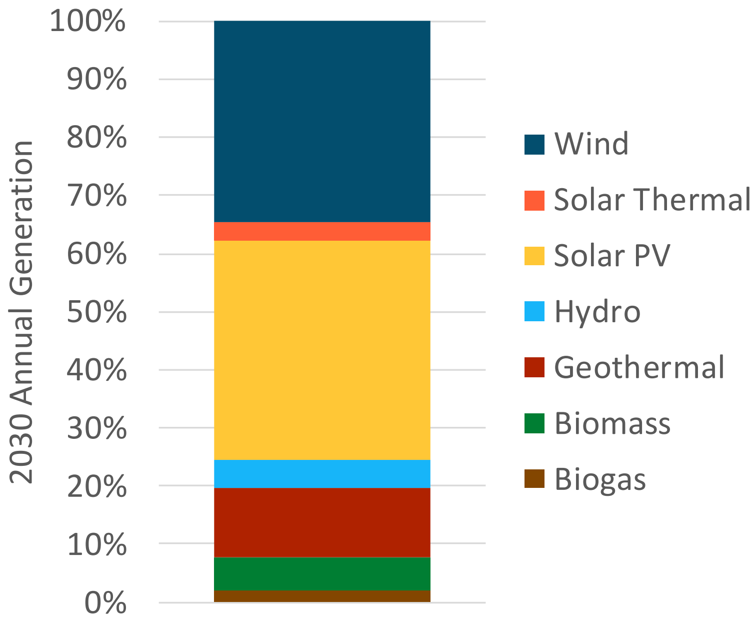


The avoided cost of energy reflects the marginal cost of generation needed to meet load in each hour. The CEC performs extensive production simulation modeling as a part of the 2015 IEPR. The avoided cost of energy reflects the marginal cost of generation needed to meet load in each hour. As with the 2016 TDVs, the production simulation cases are re-run with load shapes that are correlated to the TMY weather files. For the 2019 TDV Update, the PLEXOS production simulation model creates results from 2020-2026. Beyond 2026, marginal heat rates are held constant and energy prices are calculated using this heat rate and the natural gas price forecast

Consistent with the approach used in previous TDV updates, the production simulation cases are run using load shapes that correlate the electricity market price shapes with the statewide typical meteorological year (TMY) files for a 2009 calendar year. This means that the hottest days of the year in the TMY files will also reflect the highest TDV value hours of the year. As no change was made to the load shapes, base year, or TMY files that were used for the 2016 TDV Update, no updates were required for this step.

E3 also provided the runs of the CPUC RPS Calculator to create renewable generator expansion plans for California's Investor owned utiltiies.

Figure 12. Renewable Portfolio for 50% RPS Scenario



The production simulation generates 8,760 hourly electricity prices for 2020-2026. Beyond 2026, electricity prices are escalated with the annual increase in the 2015 IEPR natural gas price forecast. The resulting average energy price is shown in Figure 13. The energy price shape from 2026 is used for all remaining years.

Figure 13. Average Wholesale Energy Price without the cost of emissions

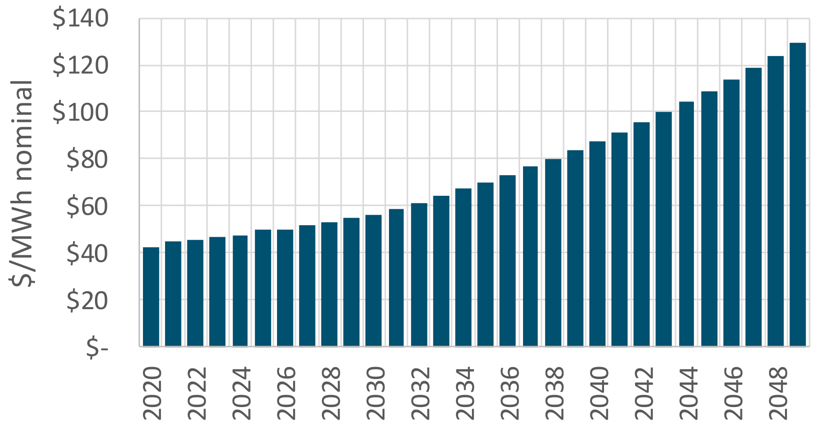
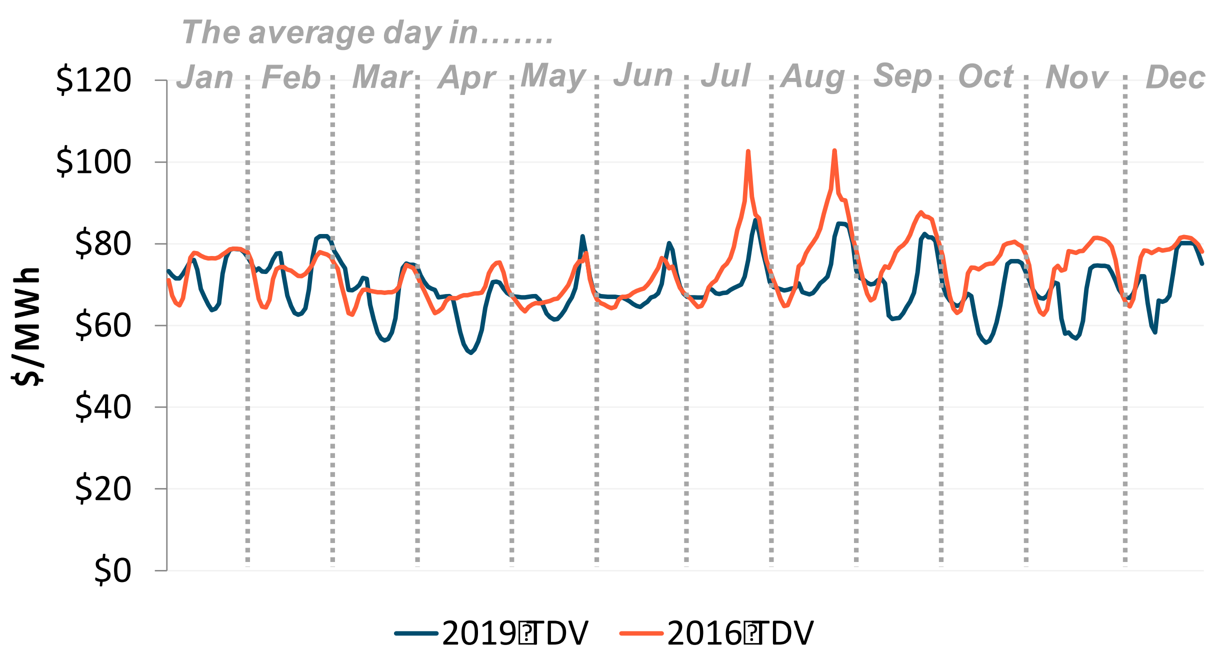
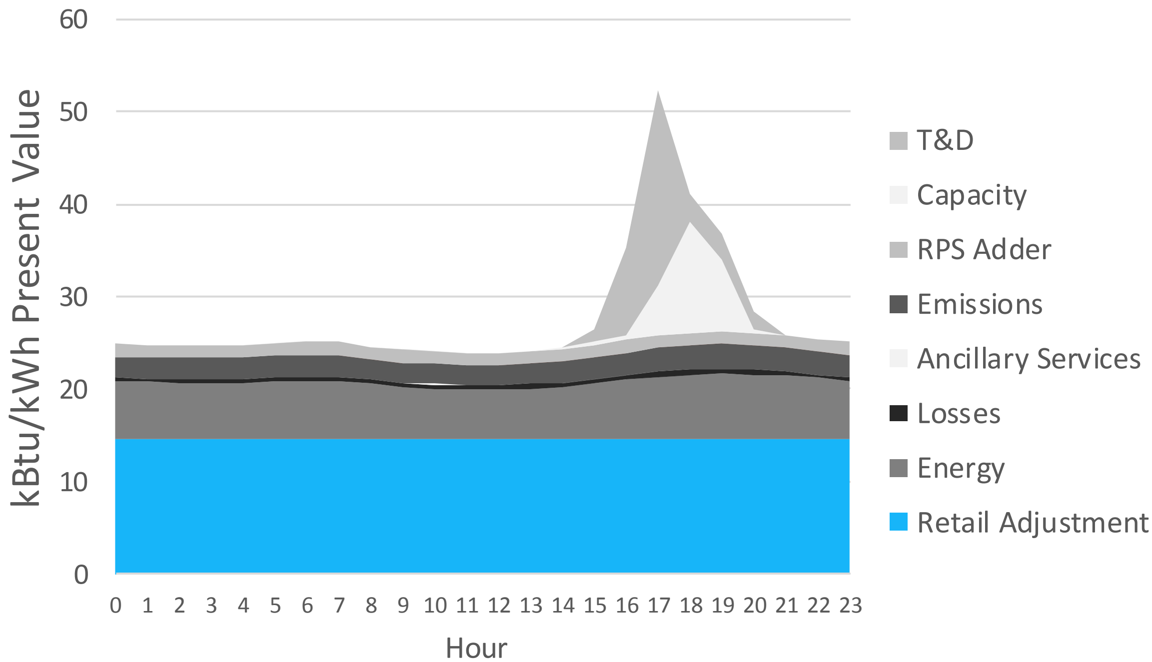


Figure 14. Wholesale Energy Price Shapes compared from 2016 to 2019 TDVs



3.1.8 RETAIL RATE ADJUSTMENT



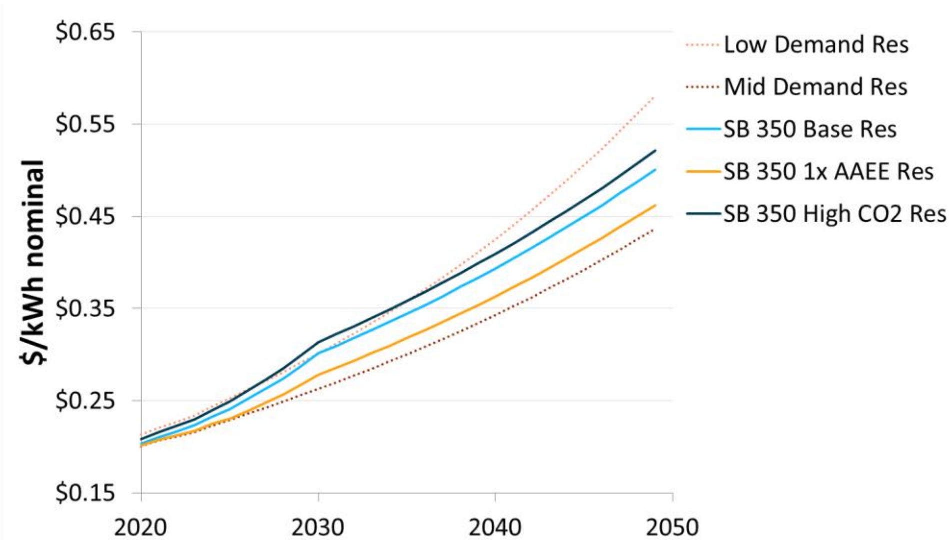
The final step in the process of developing TDV cost values is to adjust the hourly wholesale cost of energy up to the equivalent of the retail cost of energy. This step is done to ensure that the energy efficiency measures considered in the Title 24 standards process are roughly cost effective to the 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 for previous cycles of TDV were developed directly from the IEPR. The 2015 IEPR includes retail rate forecasts for a mid-demand load and 33% RPS. For the 2019 TDVs, we wanted to represent rates that were consistent with SB 350 levels of 50% renewable electricity generation and aggressive doubling of energy efficiency. To do this, we used the RPS Calculator[6] to estimate average electric retail rates both for the conditions included in the IEPR and for our SB 350 sensitivities. Using the rate results from these runs we created a percentage multipliers and applied them to the 2015 IEPR mid-case electric rate forecast. The resulting residential average retail rates are

[6] CPCU RPS Calculator Version 6.2

shown in Figure 15. All SB 350 Retail Rates are hgher than the original IEPR Mid-Demand Case, but are also lower than the IEPR Low-Demand case. This is due to the fact that the IEPR Low-Demand case has lower expected electrifity demand than our doubling of energy efficiency assumed in our SB 350 Base and High CO2 price cases.

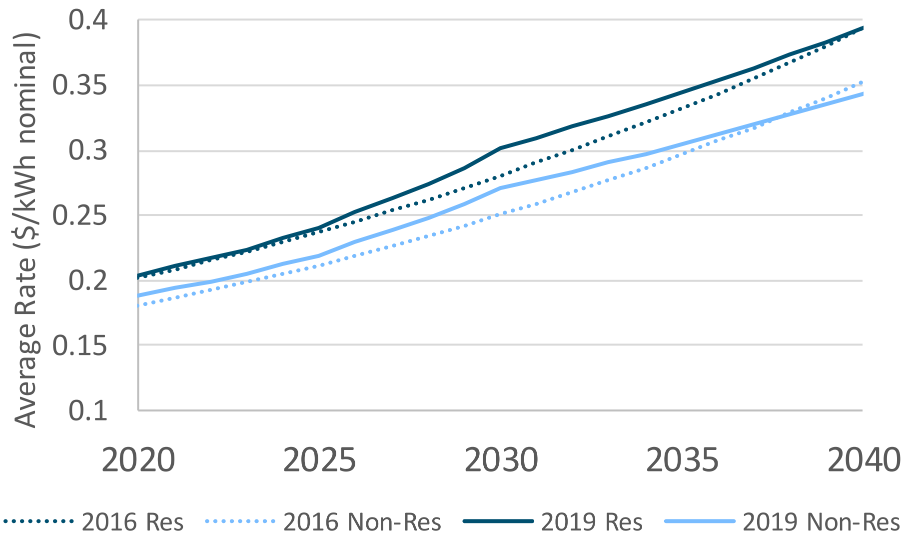
Figure 15. SB 350 Retail Rate Projections compared to IEPR Low- and Mid-Demand Retail Rates



The IEPR calculates average residential and commercial rates for PG&E, SCE, SDG&E, LADWP, and SMUD through 2026. For the 2019 TDVs, the utility-specific rates are combined into a statewide weighted average using electricity consumption forecasts from 2015 IEPR Form 1.1. After 2026, the rate forecasts (modified by the multipliers described above) are escalated using the compound average growth rate observed from 2020 through 2026 (2.7%/yr. nominal increase for residential and 2.4%/yr for non-residential).

The resulting assumed rates for the 2019 TDVs are shown for residential and non-residential customers and compared to 2016 TDV retail rates in Figure 16.

Figure 16. Comparison of base case electricity retail rate forecasts in 2016 and 2019 TDVs.[7]



3.2 Updates to Natural Gas TDV Inputs

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. The components are:

- Retail price forecast
- Wholesale commodity price forecast
- Emissions Costs
- Distribution costs

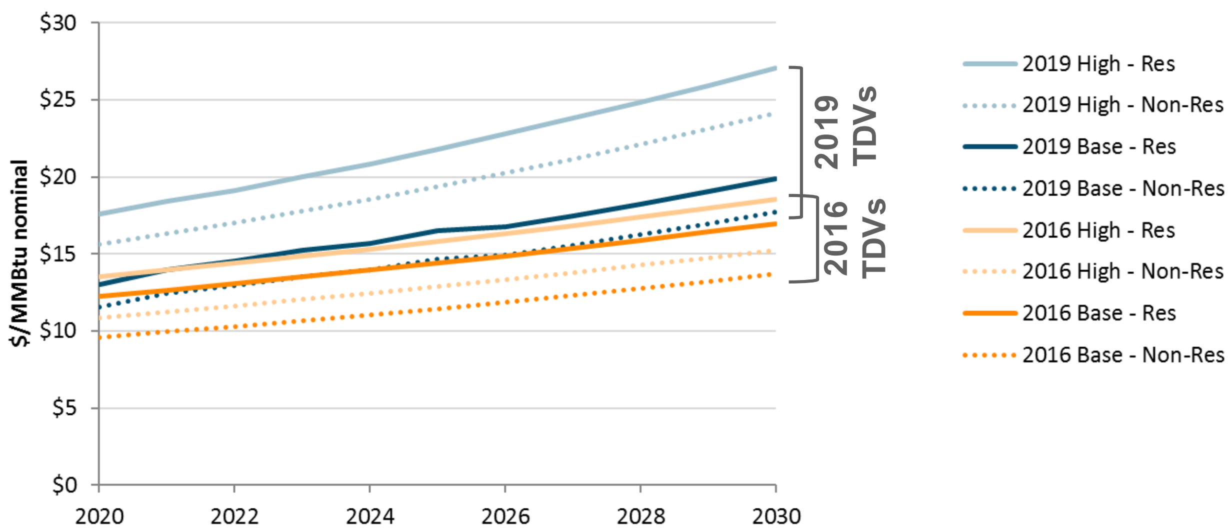
3.2.1 NATURAL GAS RETAIL RATES

The natural gas retail price forecast is taken from the 2015 IEPR (Table 14. Reference Case). The TDVs use the IEPR average statewide natural gas end-user prices for residential and commercial customers. We fill the intermediate years by linear interpolation, and extrapolate past 2026 using the 2020-2026 compound annual growth rate. The annual end user prices are also adjusted to reflect monthly

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

variations in natural gas commodity costs. Those adjustment factors are the same as those used for the 2013 and 2016 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 17 below.

Figure 17. Comparison of gas retail rate forecasts in the 2013 and 2016 TDVs.

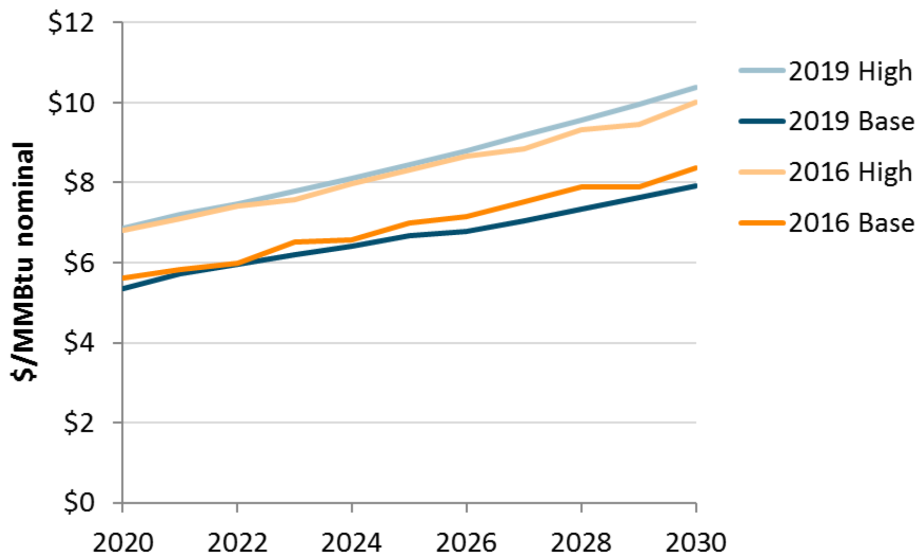


3.2.2 WHOLESALE COMMODITY COSTS

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.

Figure 18. Henry Hub Natural Gas Commodity Costs



3.2.3 EMISSION COSTS

Emission values are calculated based on the emissions rates of combusting natural gas in typical appliances. The CO_2 emissions rate for natural gas combustion are derived from the CPUC's energy efficiency avoided cost proceeding (R.04-04-025) at 0.0585 tons/MMBtu.

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, natural gas rates are assumed to include CEC mid-IEPR carbon prices. Because of the retail rate adjustment, inclusion of a carbon price does not impact the shape or level of the natural gas TDVs, but this breaking out this cost does provide greater clarity into the TDV components.

3.2.4 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.

3.3 Updates to Propane TDV Inputs

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

- Retail Cost
- Emissions Costs

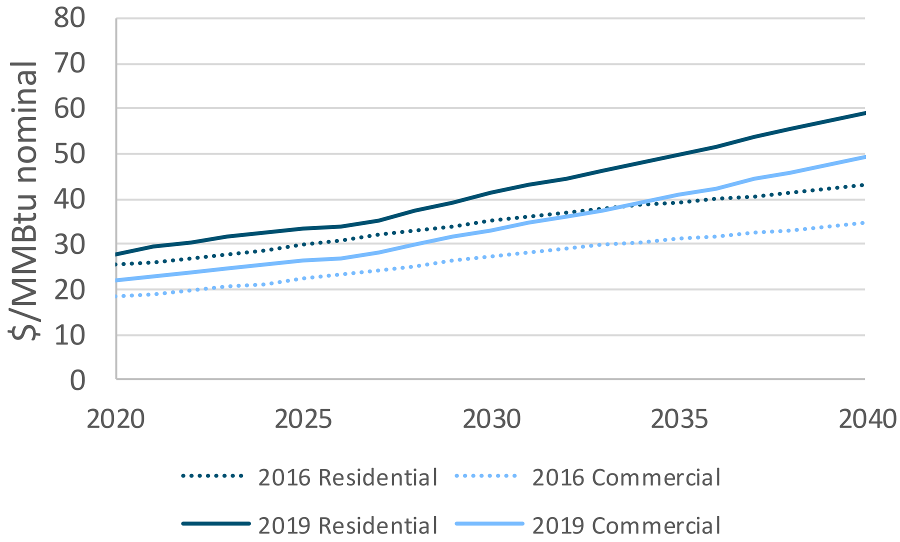
3.3.1 RETAIL RATE

The propane forecast is based on the long-run relationship between U.S. Department of Energy (DOE) EIA 2015 Annual Energy Outlook Pacific region propane price forecast, natural gas price forecast, and the TDV natural gas end user price forecast described above.[8] The EIA forecast for propane and natural gas 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.

[8] 2015 EIA Annual Energy Outlook

Figure 19. Comparison of propane retail price forecasts in the 2016 and 2019 TDVs.



3.3.2 EMISSIONS COST

Emission values are calculated based on the emissions rates of combusting propane in typical appliances. The CO_2 emissions rate for propane combustion are derived from the CPUC's energy efficiency avoided cost proceeding (R.04-04-025) at 0.07 tons/MMBtu.

In general, we seek to apply the same methodology to the development of the propane 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, propane rates are assumed to include CEC mid-IEPR carbon prices. Because of the retail rate adjustment, inclusion of a carbon price does not impact the shape or level of the propane TDVs, but this breaking out this cost does provide greater clarity into the TDV components.

4 Results

4.1 Electricity

Figure 20: Climate Zone 1 Residential (30 yr)

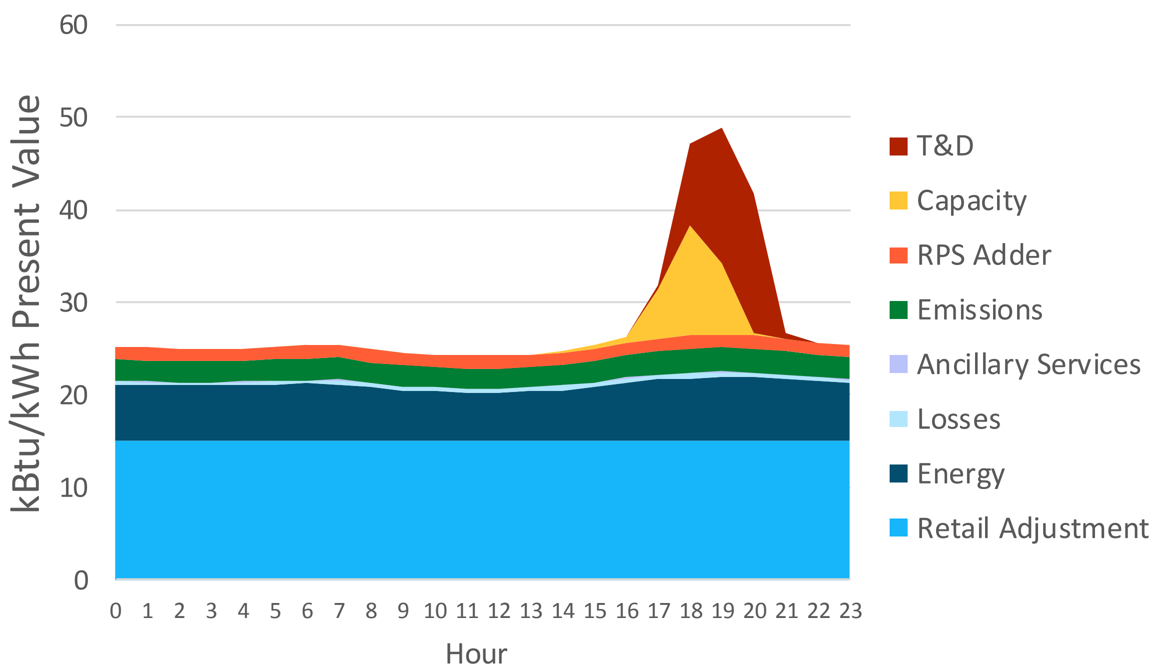


Figure 21: Climate Zone 2 Residential (30 yr)

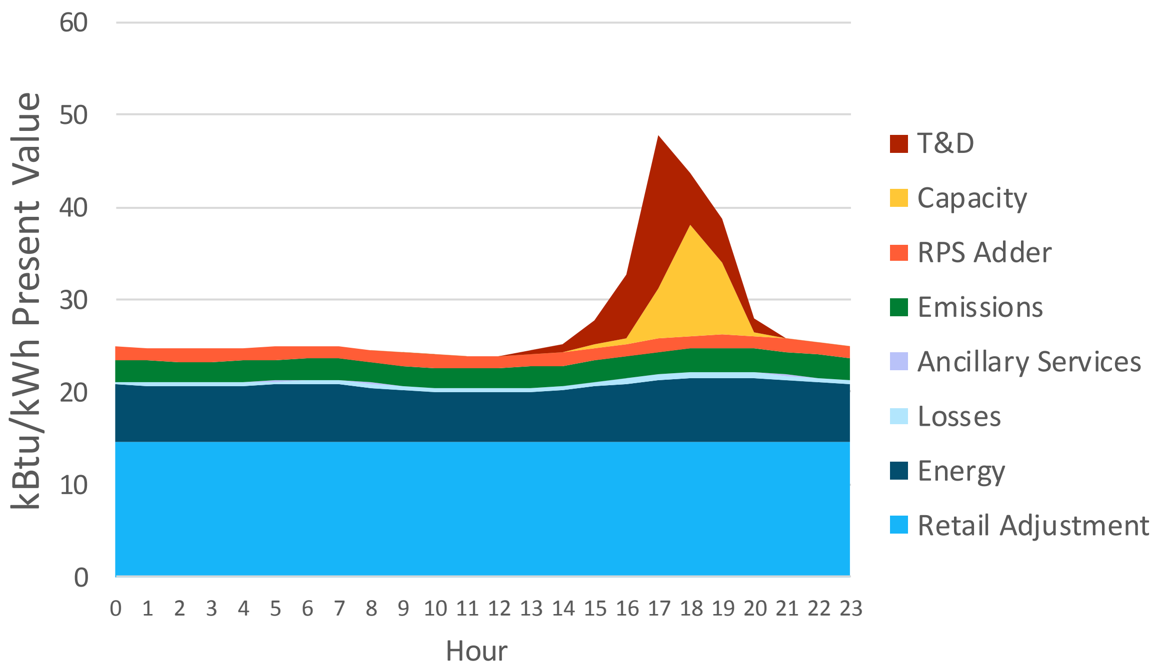


Figure 22: Climate Zone 3 Residential (30 yr)

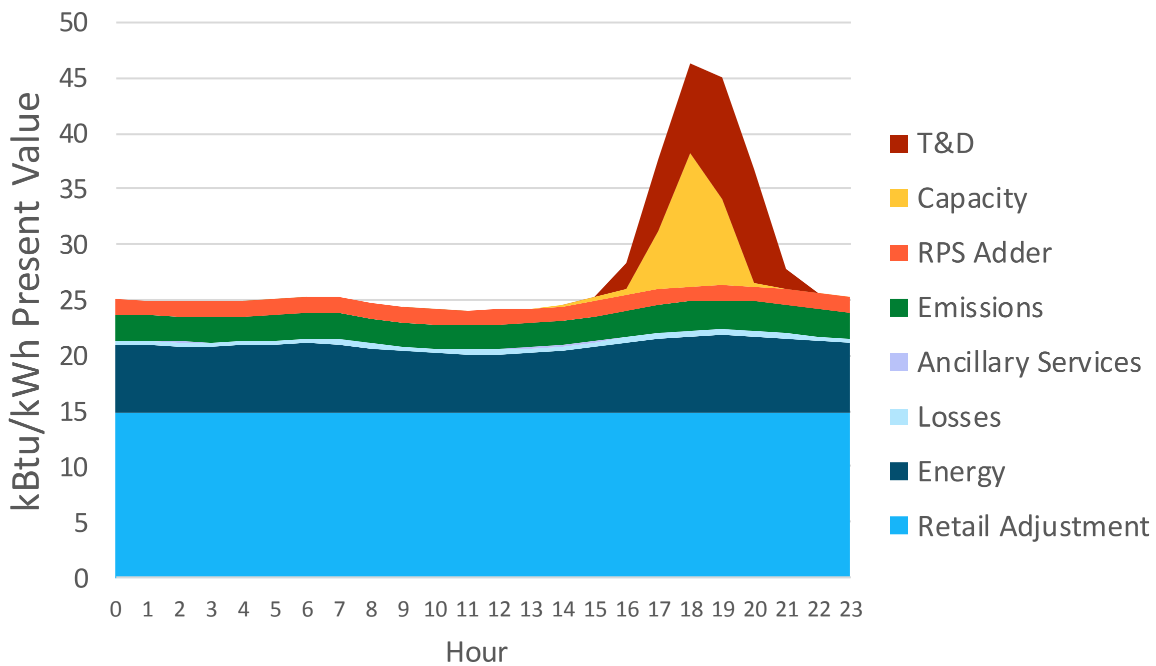


Figure 23: Climate Zone 4 Residential (30 yr)

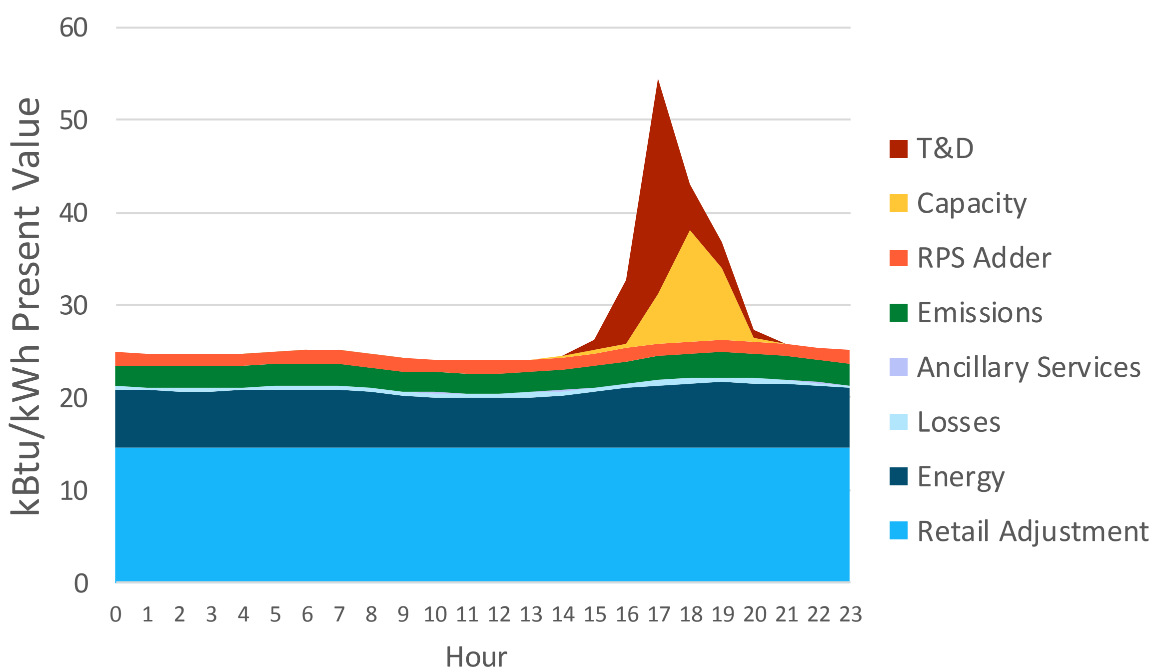


Figure 24: Climate Zone 5 Residential (30 yr)

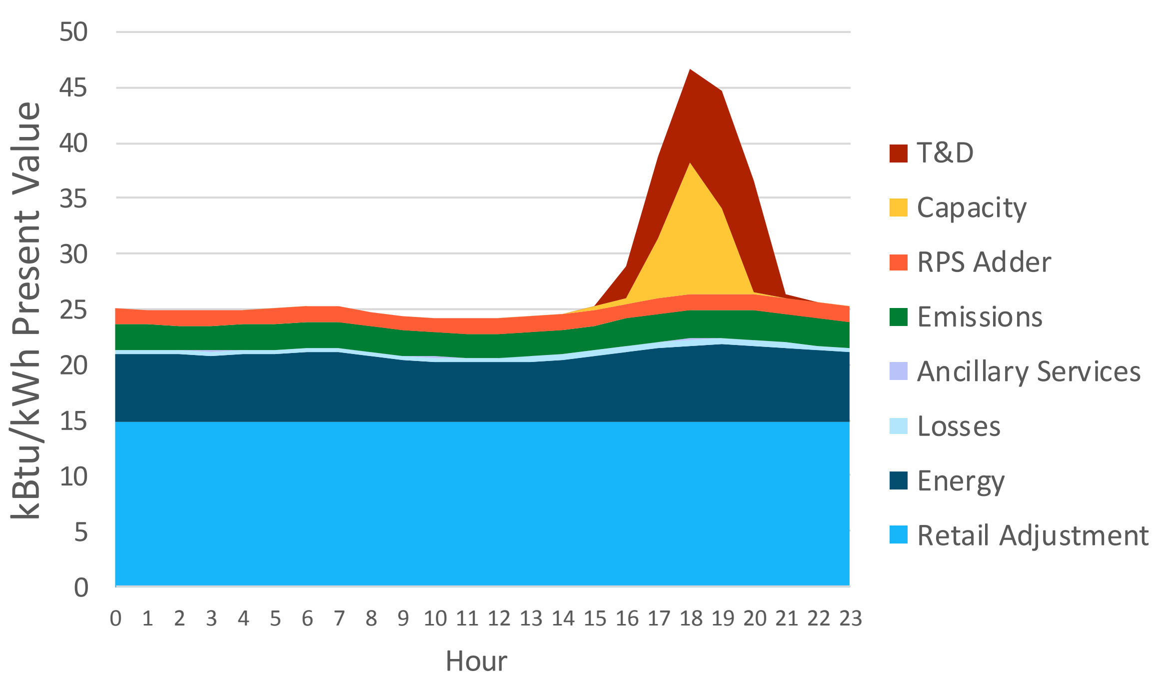


Figure 25: Climate Zone 6 Residential (30 yr)

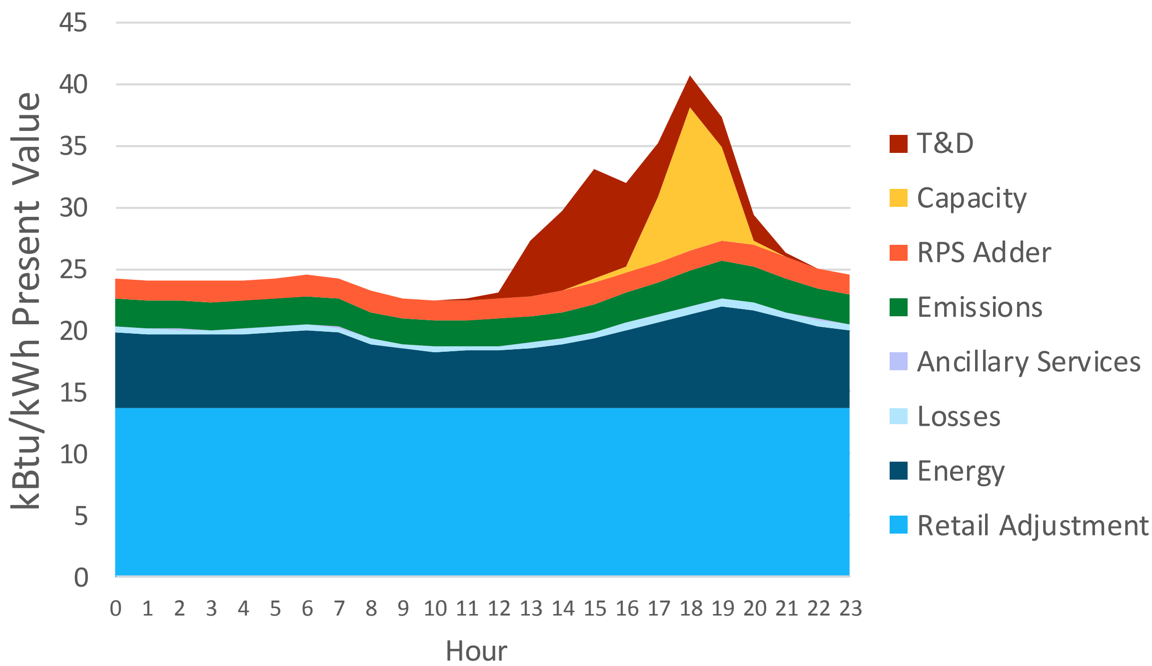


Figure 26: Climate Zone 7 Residential (30 yr)

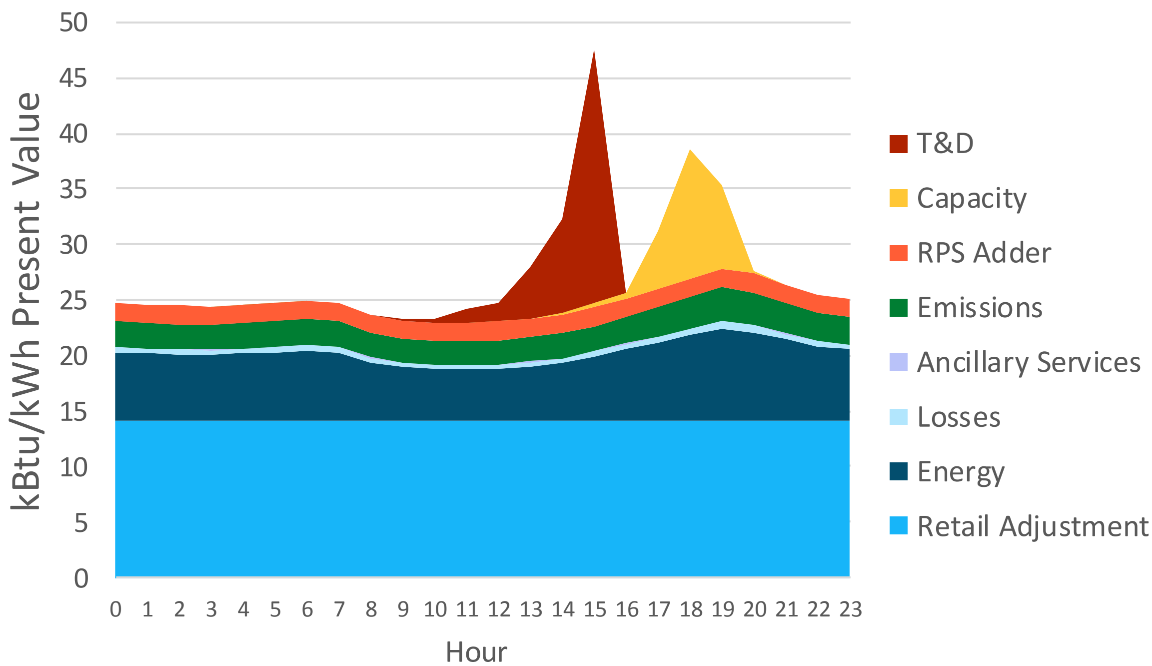


Figure 27: Climate Zone 8 Residential (30 yr)

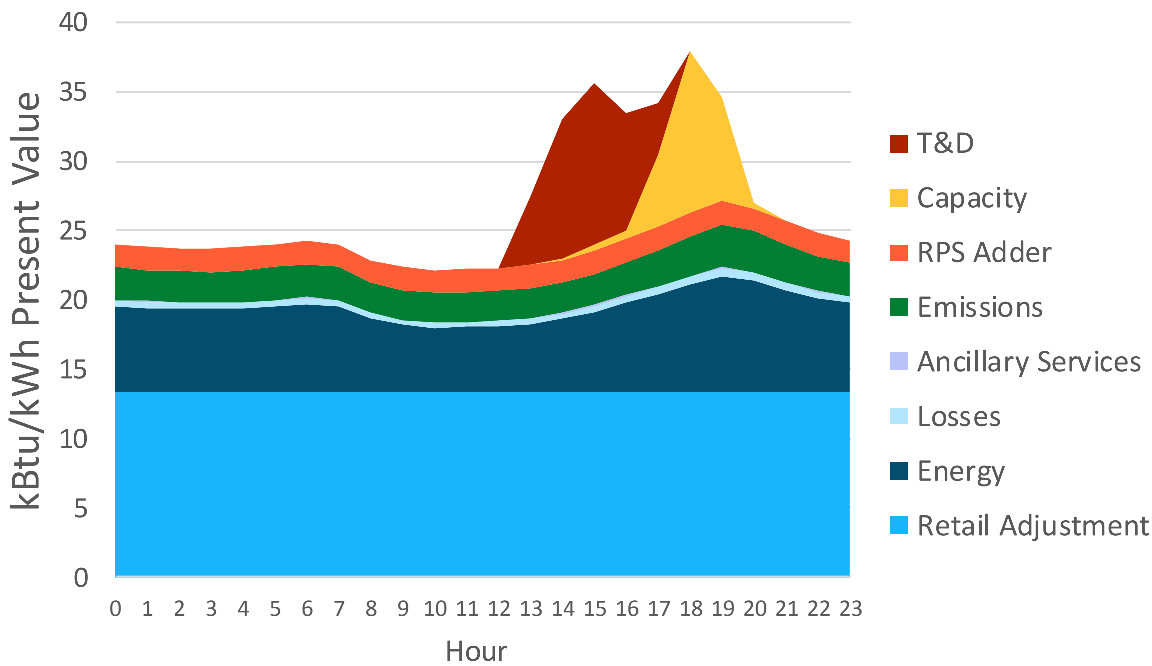


Figure 28: Climate Zone 9 Residential (30 yr)

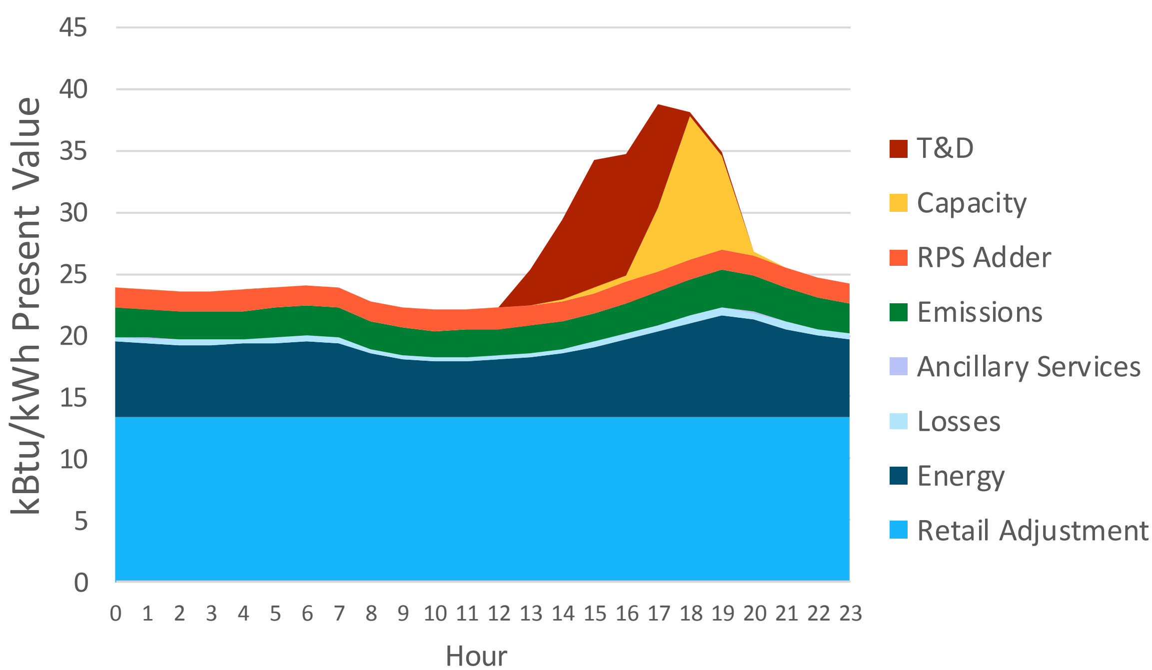


Figure 29: Climate Zone 10 Residential (30 yr)

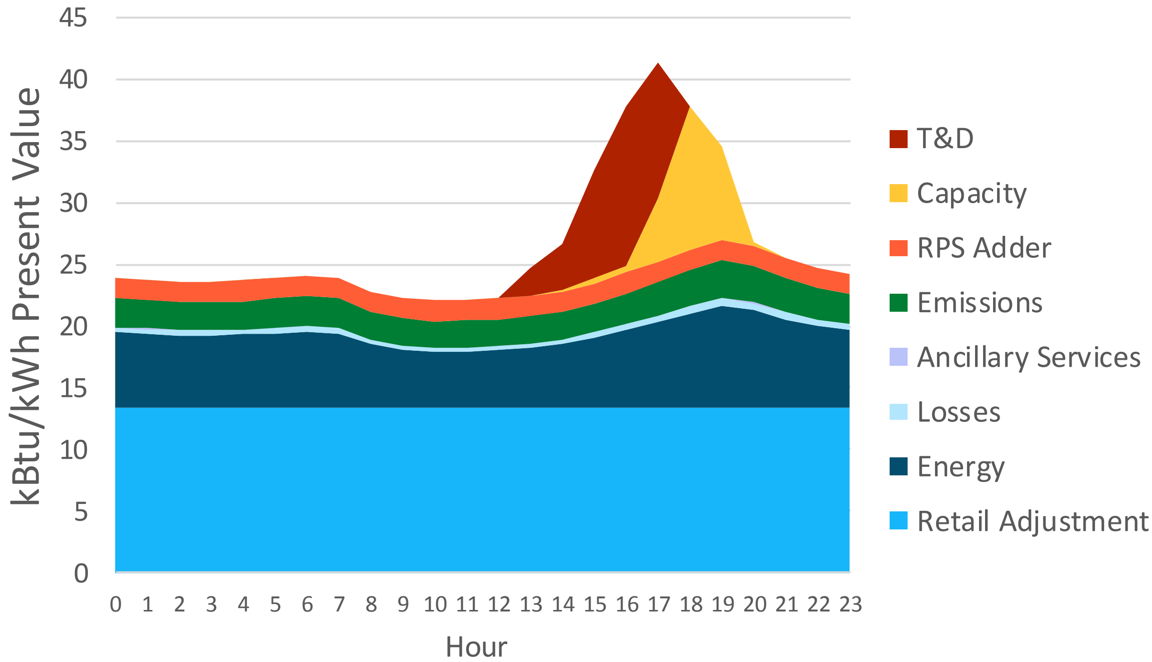


Figure 30: Climate Zone 11 Residential (30 yr)

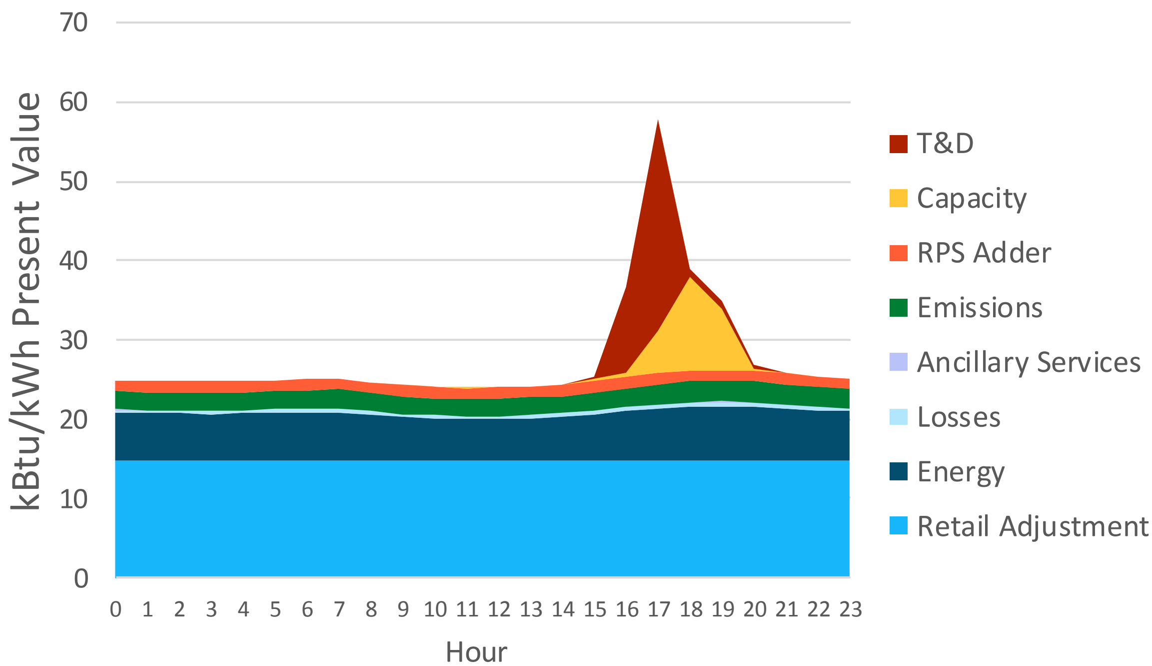


Figure 31: Climate Zone 12 Residential (30 yr)

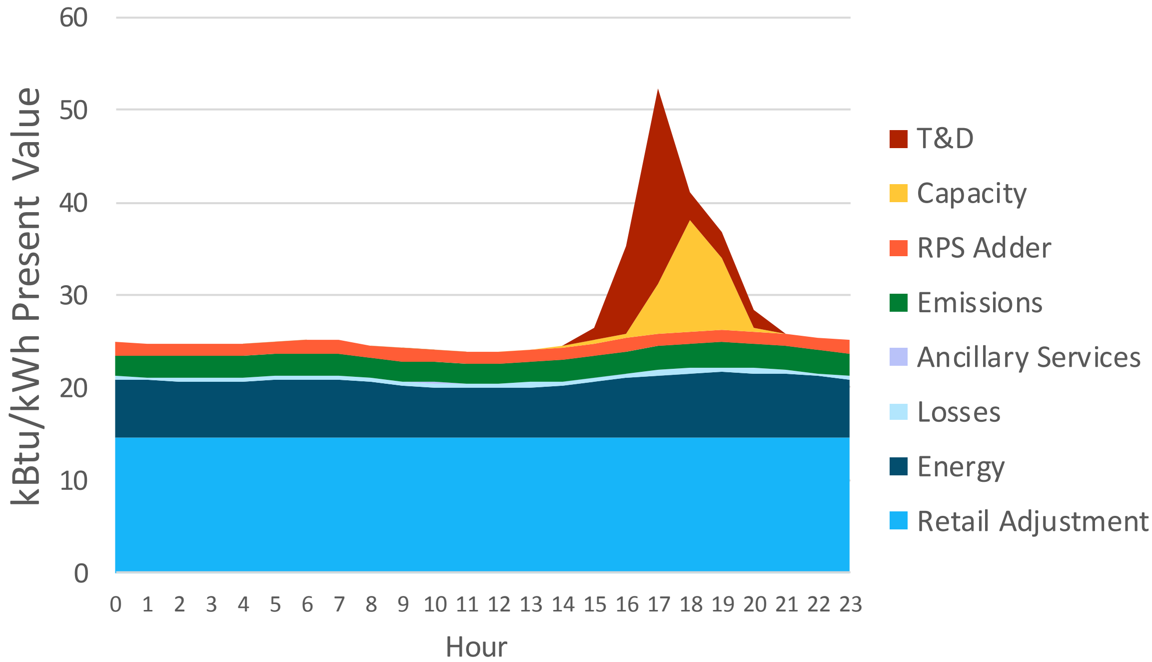


Figure 32: Climate Zone 13 Residential (30 yr)

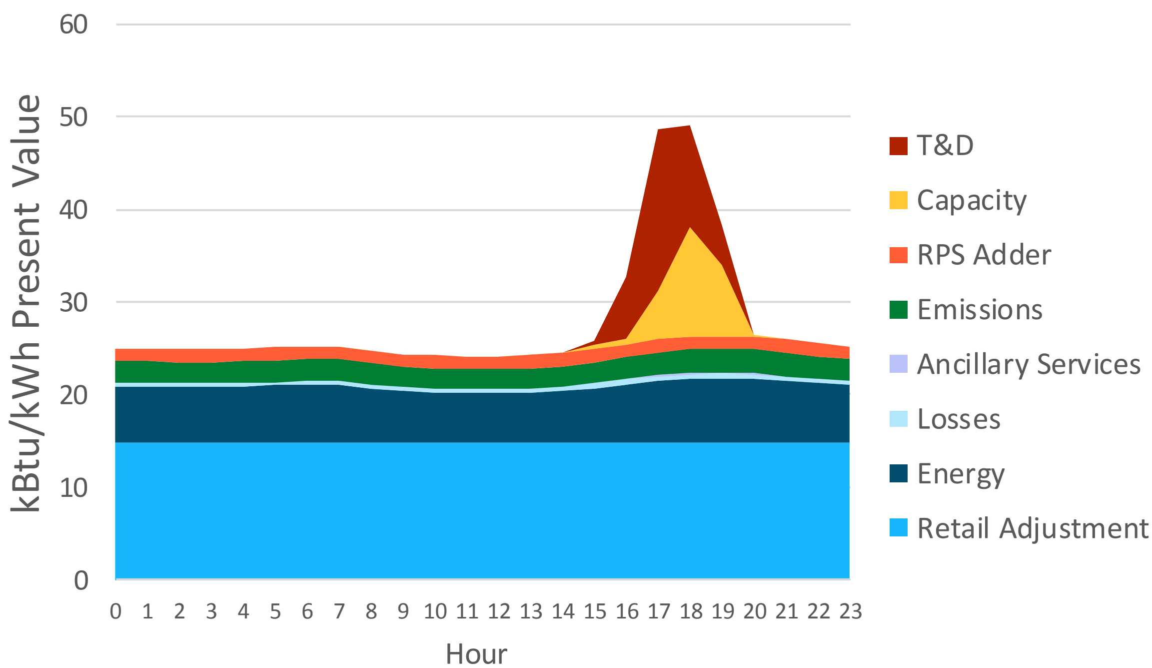


Figure 33: Climate Zone 14 Residential (30 yr)

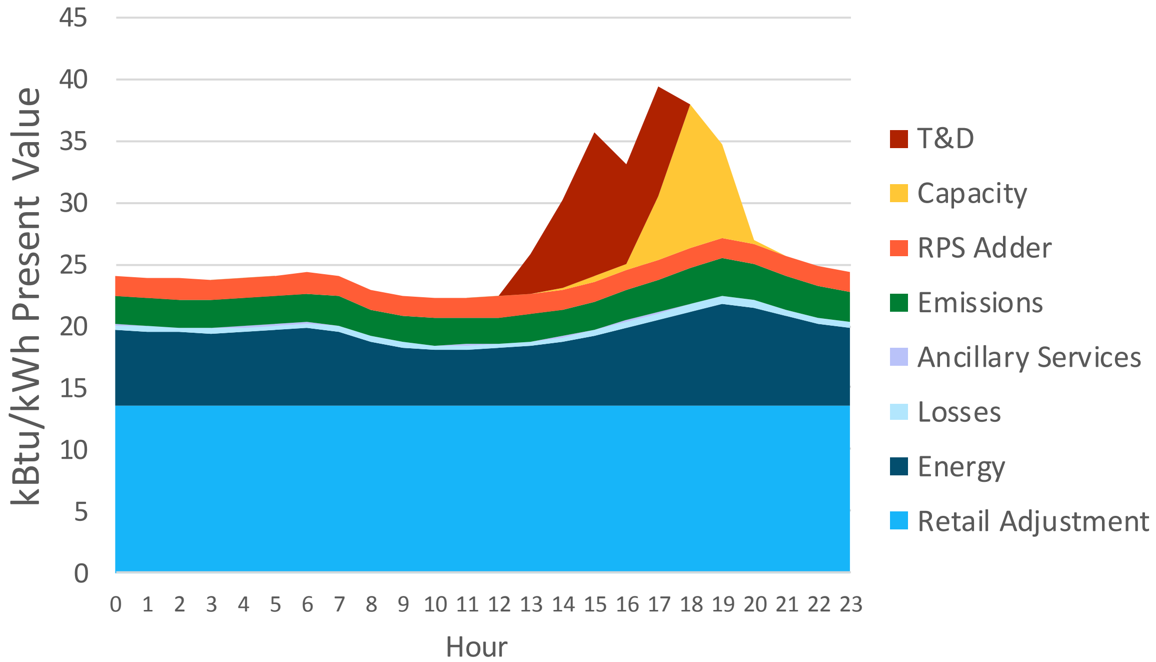


Figure 34: Climate Zone 15 Residential (30 yr)

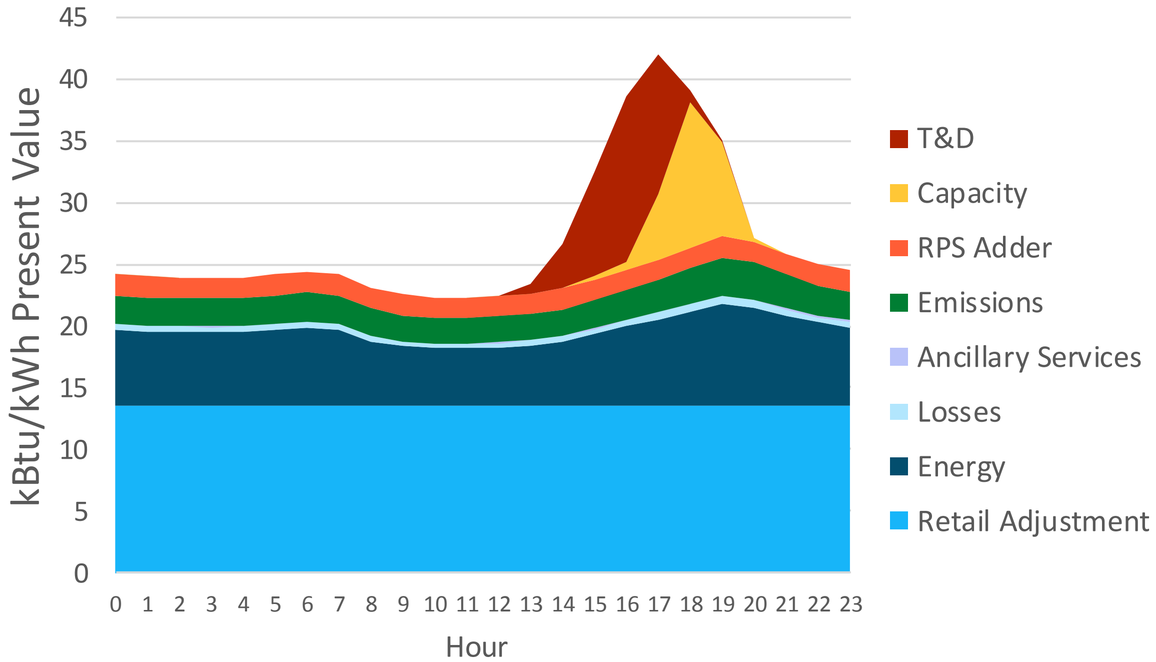


Figure 35: Climate Zone 16 Residential (30 yr)

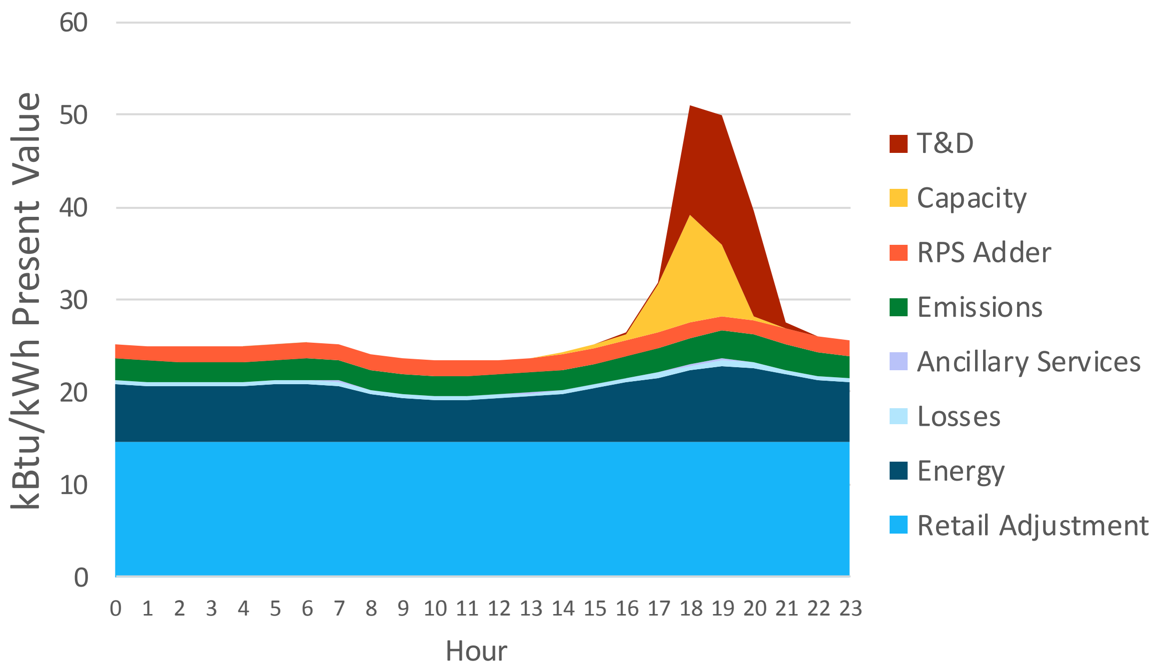
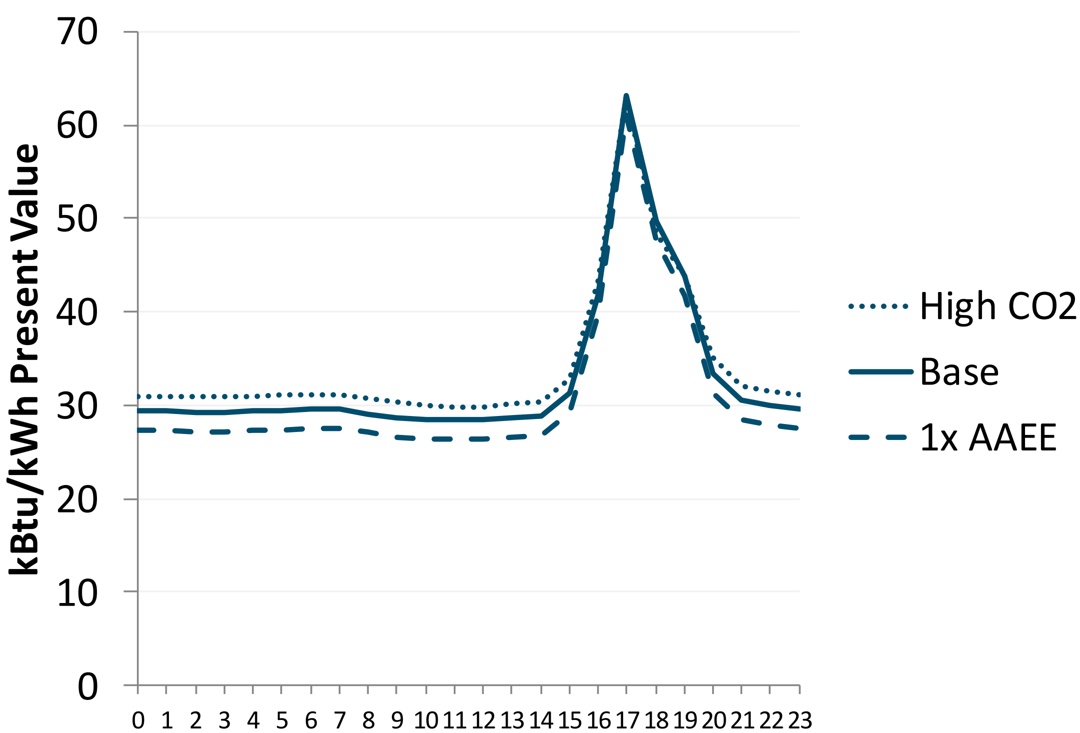
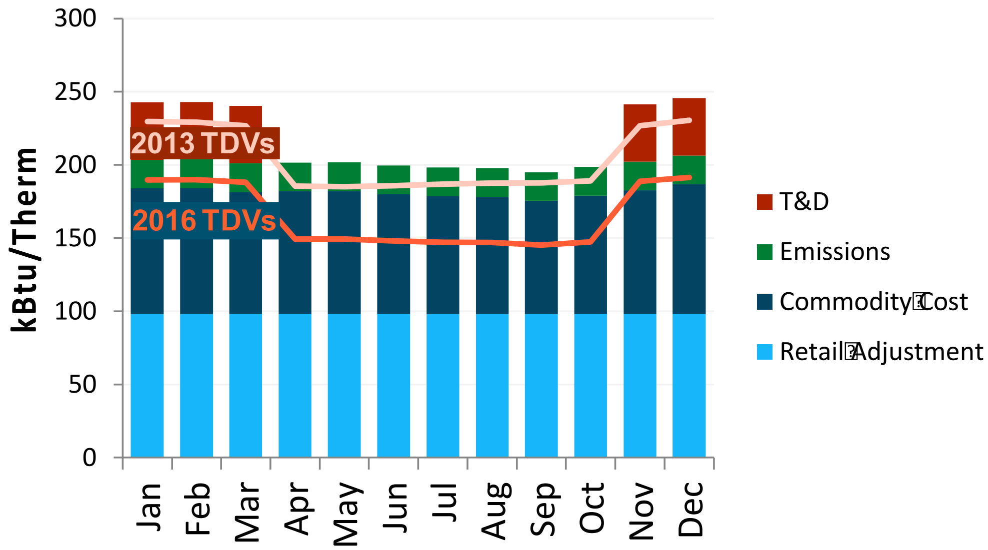


Figure 36. Average day TDV values by scenario, CZ 12



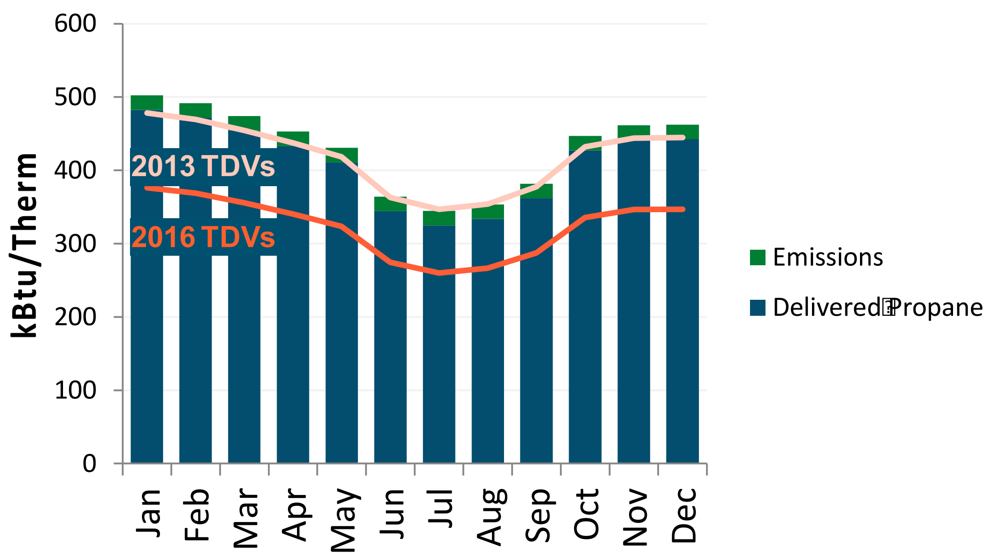
4.2 Natural Gas

Figure 37. Natural Gas TDVs by month and component



4.3 Propane

Figure 38. Propane TDVs by month and component



5 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*".[9] 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 2019 TDV development process is largely the same as the approach taken for 2016, 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.

[9] 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 2008, 2013, and 2016 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 conversion factor (based on the 2005 forecasted NPV gas cost) is $0.173/kBtu for 30-year residential TDVs (Table 4). Multiplying the TDV expressed in energy units by this $/kBtu factor yields NPV $/kWh and $/therm TDVs (See Table 5). The non-residential conversion factors for 30-year and 15-year measures are $0.154/kBtu and $0.089/kBtu respectively.

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.

Table 13. TDV Conversion Factors, NPV $/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 13.

The resulting average TDV values (unweighted) across all climate zones and hours of the year are shown in Table 14 for the 2008, 2013, 2016, and 2019 TDV Update cycles.

Table 14. Statewide average TDV factors for Natural Gas and Electricity, 2008 - 2016

Time Period	2008	2013	2016	2019
30 Year Residential				
Natural Gas (NPV$/Therm)	$24.32	$27.68	$28.64	$34.25
Electricity (NPV $/kWh)	$2.33	$3.62	$3.73	$4.74
15 Year Non-Residential				
Natural Gas (NPV$/Therm)	$12.72	$14.59	$12.75	$16.00
Electricity (NPV $/kWh)	$1.63	$1.85	$1.83	$2.45
30 Year Non-Residential				
Natural Gas (NPV$/Therm)	$23.97	$25.96	$23.62	$30.44
Electricity (NPV $/kWh)	$2.66	$3.36	$3.19	$4.24

TDVs for 2008 are expressed in $2008, 2013 are in $2011, 2016 are in $2017, and 2019 are in $2020

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 and 2019 TDVs.

A.2 Modeling considerations

Modeling a load shape which captures the relationship between historic hourly load and weather data should consider the following:[10]

- 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.

[10] 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°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).
    - 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.[11]

+ 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

[11] 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 39 shows the predicted and actual load duration curves for 2007. Figure 40 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 39. 2007 Load Duration Curve for SCE

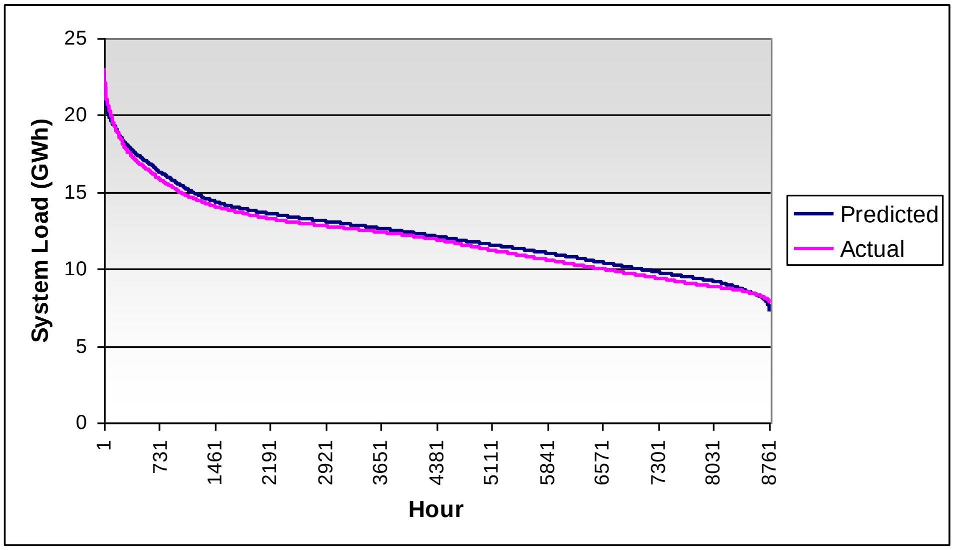
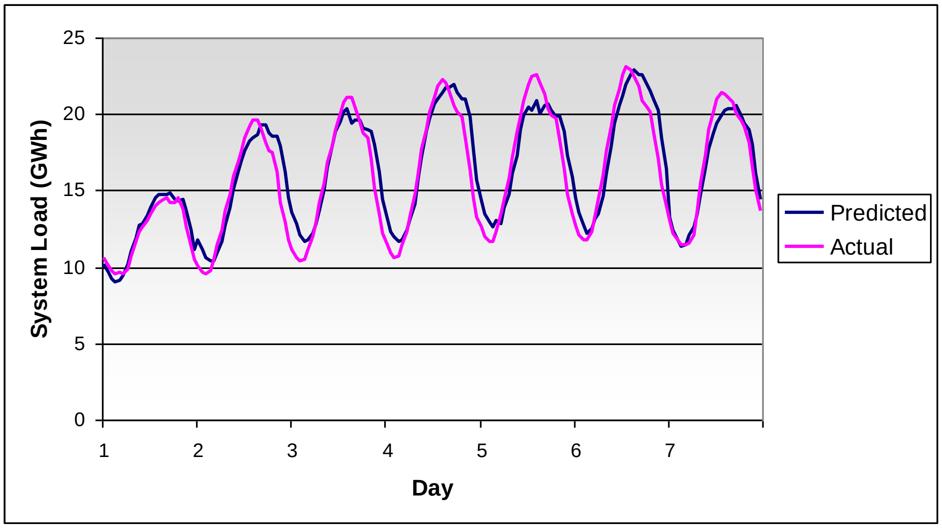


Figure 40. 2007 Peak Load Week for SCE



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 15. 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