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2019 Draft TDV Updates

CEC Staff Workshop
May 12, 2016

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Agenda

+ **TDV Methodology Background and History**
+ **SB350 Considerations**
  - 3 sensitivities compared
+ **Updates to Methodology**
  - T&D Marginal Cost Allocation Based on Actual Load Data
+ **Updates to Inputs**
+ **Draft Results and Comparison**
  - 2019 vs. 2016 TDV Results

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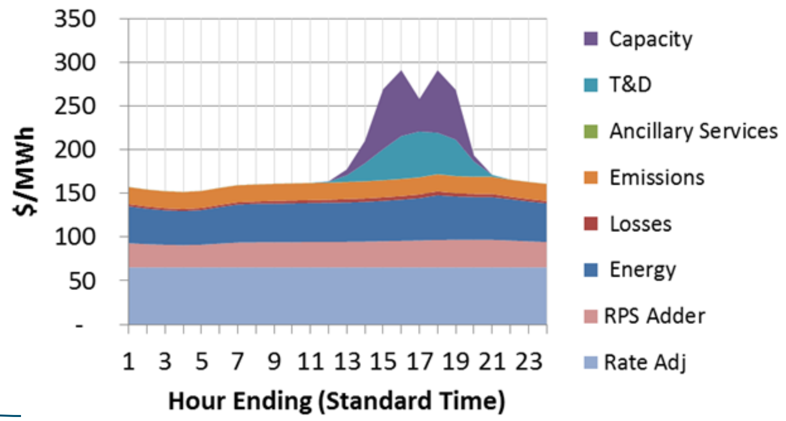
TDV METHODOLOGY BACKGROUND

What are TDVs?

- **The TDVs are a long term forecast of hourly electricity, natural gas and propane costs to building owners and are used for cost-effectiveness activities in Title 24 Building Code**
- **The TDVs answer the question of what is cost-effective in the long term, as required by the Warren-Alquist Act**

- Time-differentiation reflects the underlying marginal cost of producing and delivering energy
- Area-correlation reflects underlying marginal cost shapes correlated with each climate zones weather file

Sample Annual Average Electric TDV, 2016



Similar for natural gas and propane

What are TDVs used for?

- **Two main uses for TDVs**

  1. Cost-effectiveness analysis in the CASE studies (Codes And Standards Enhancement studies) used to adopt new building measures in the prescriptive standard

  2. Code compliance for buildings that wish to vary from the prescriptive standard using the ACM (alternative calculation methodology). TDVs are embedded in California Building Energy Code Compliance software (CBECC)

- **TDV is also the metric that has been adopted in the IEPR for measurement of zero-net energy Σ TDV = 0**

Frequently Asked Questions (1)

- **Why do we use statewide average electricity and natural gas retail rate levels?**
  - With this approach, the code has similar overall stringency state wide and there can be similar construction practices across the state. Note that there are still variations for climate.
- **Why don't we use the actual retail rate structures that are in place?**
  - We want the building code to be relatively stable over time and from cycle to cycle, the TDVs reflect a 'perfect' marginal cost of service which is a long term signal for retail rates
  - By using the underlying system marginal costs we are reflecting building measures that provide the greatest underlying value to the energy system, even if retail rates are flat or have a different time of use period

Frequently Asked Questions (2)

- **Why are the units of TDV in kBTU/kWh and kBTU/therm if they measure cost-effectiveness?**
  - The TDVs are calculated in lifecycle dollars per unit of energy ($/kWh, $/therm) in each hour and climate zone in California
  - For the building code compliance, they are converted to different units of kBTU/kWh and kBTU/therm using fixed multipliers

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SB 350 CONSIDERATIONS

SB350 Considerations

- **SB350 calls for 50% utility-procured renewable electricity and a doubling of energy efficiency by 2030**
- **Base Case; "SB-350-Friendly" scenario**
  - 2015 IEPR mid-case load forecast (including mid-case EV and mid CO2 price forecasts)
  - 50% renewables by 2030 from in-state resources
  - A doubling of the 2015 IEPR Additional Achievable Energy Efficiency by 2030
  - Diablo Canyon Nuclear Facility is retired

Sensitivities

- Several sensitivities have been evaluated since the implementation plans for SB350 are not yet completed

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

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UPDATES TO TDV T&D ALLOCATION METHODOLOGY

T&D Updated Methodology

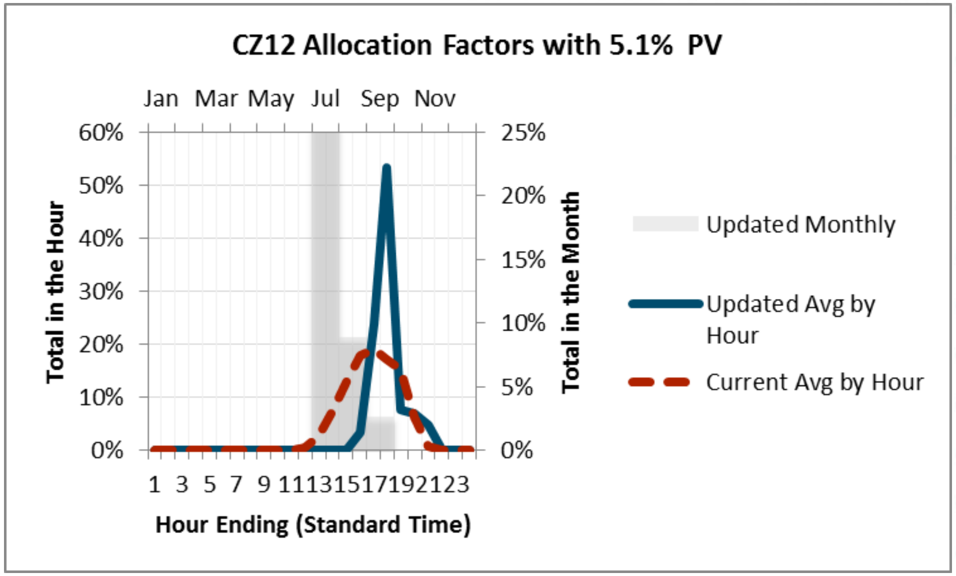
- **New methodology for T&D avoided cost allocation using actual distribution load data, not the temperature proxy that we have been using**
- **Benefits**
  - More accurately reflects usage patterns in a climate zone
  - Allows for local PV effects to be included
  - Is more consistent with industry view of peak demand
    - Provides more focused value in fewer hours to better value dispatchable options

T&D Allocation Method

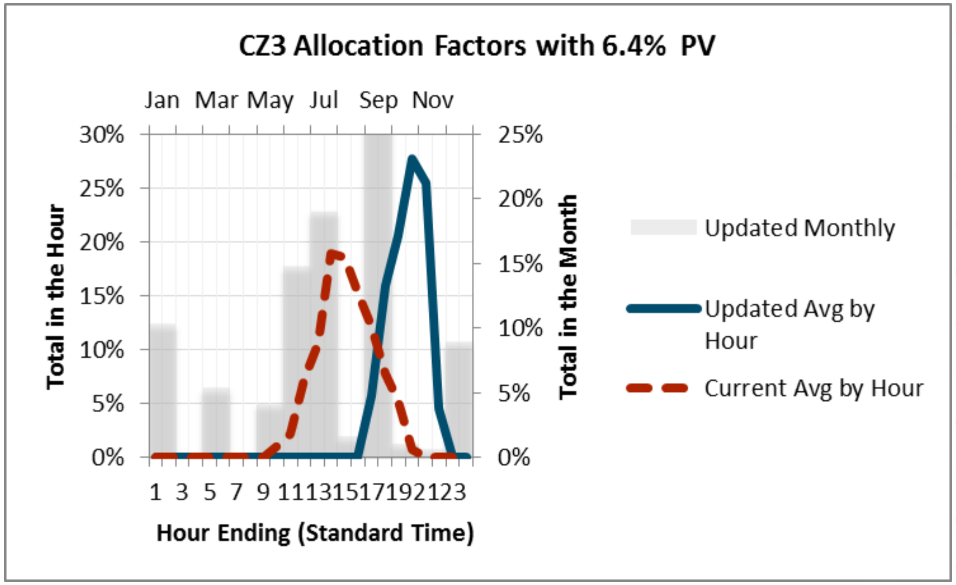
- **Use regression analyses to determine the relationship of area hourly loads to temperature**
  - Variables include dry-bulb temp, cooling degree hours, heating degree hours, lagged variables, moving averages of variables, as well as standard modeling dummy variables
  - Adjusted R-square results typically around 90%.
- **Apply the regression equations to the CTZ weather files to derive predicted CZ hourly loads**
- **Derive 2017 allocation factors based on the predicted hourly loads**
- **Adjust predicted loads for additional solar PV adoptions, and derive 2030 allocation factors**

Effects of the Update

+ **Concentration into fewer hours is common**

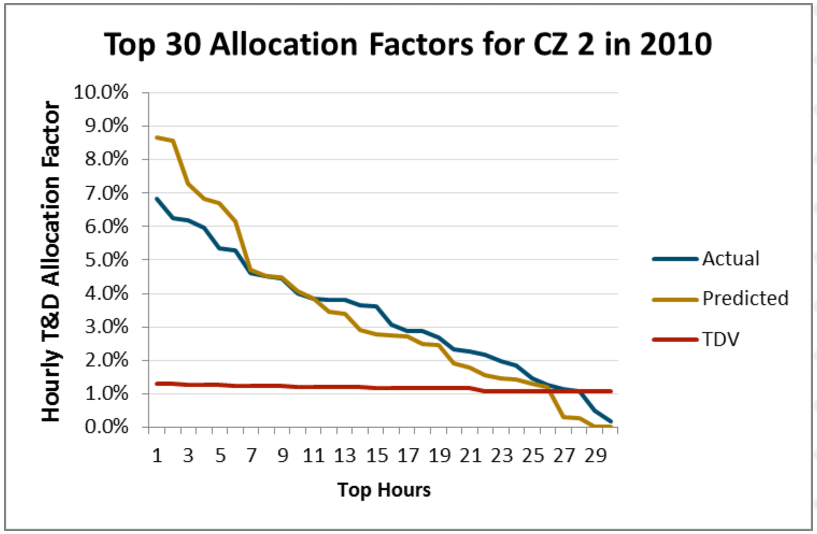


+ **Shifting to later hours also occurs in most CZ's**



Update Places higher Emphasis on Top Hours

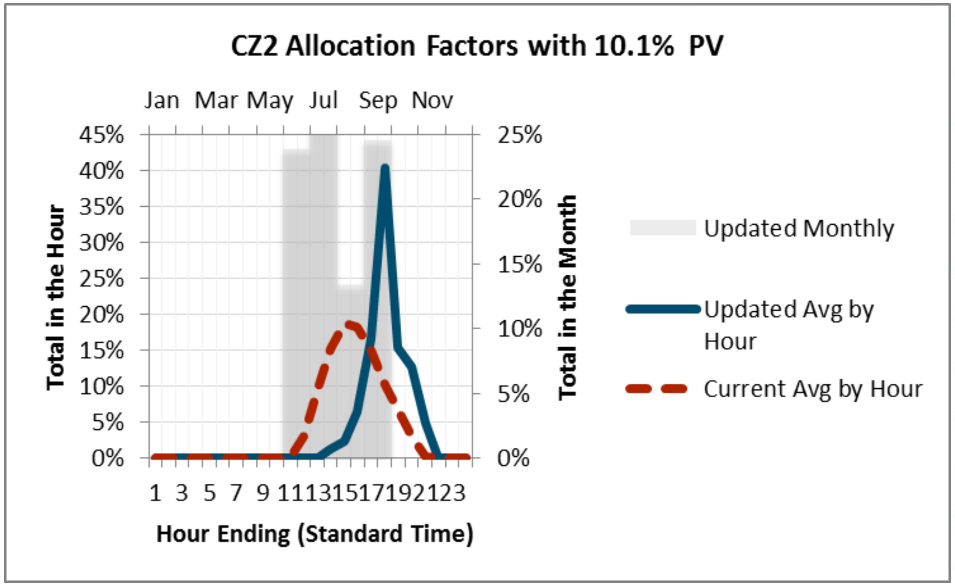
- Allocation factors shown based on actual and regression-predicted 2010 loads
- Allocation based on the PCAF method that is commonly used for T&D cost allocation. Factors kept from 2-250 hours.
- New factors are more appropriate for evaluating dispatchable technologies.



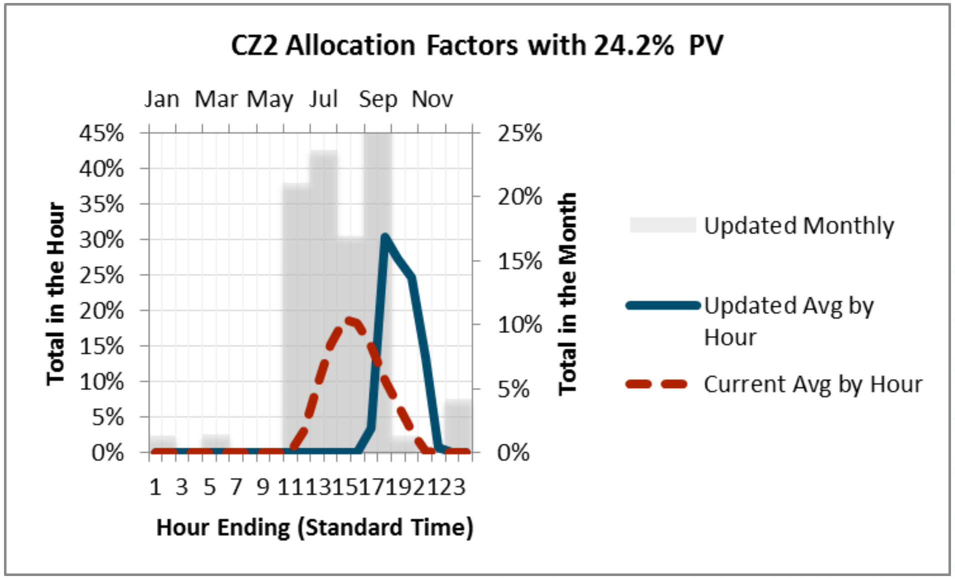
Increased Forecast Local PV also Affects the Allocators for 2030

- Peak shifts to later hours
- Peak can include other months
- But effect through 2030 is moderate

2020 Allocators



2030 Allocators



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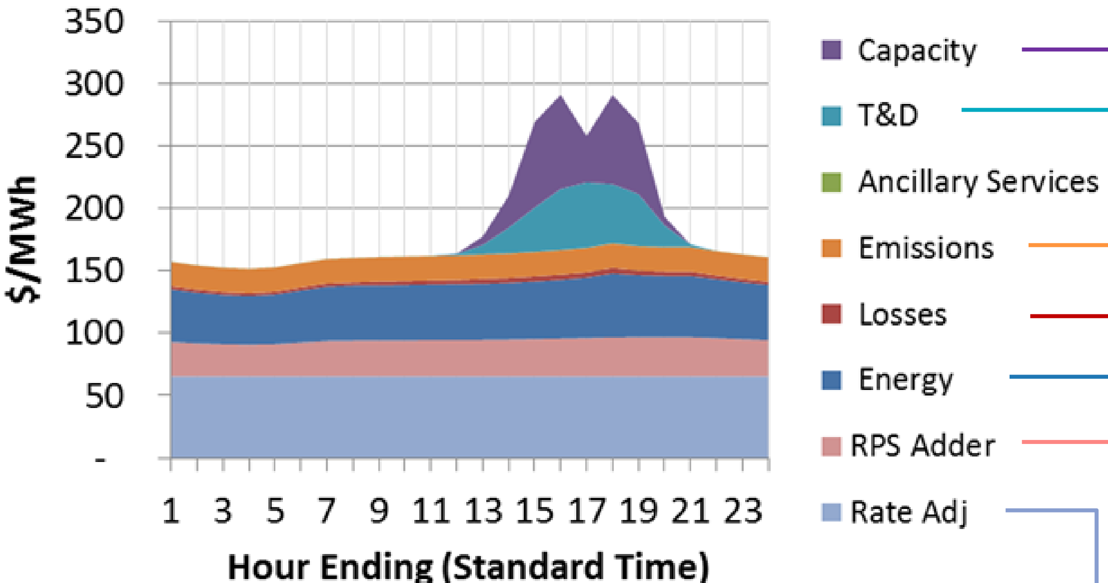
UPDATES TO TDV INPUTS

- ELECTRICITY
- NATURAL GAS AND PROPANE

Updated Inputs to Electricity TDV

Sample Electric 2016 TDV – Residential CZ12



Updated avoided capacity costs for SB350

Updated T&D costs

Updated ancillary services costs

Updated emissions cost

Same loss %'s → new value

Updated PLEXOS production simulation to match new load forecasts and SB350

Updated marginal costs of renewables

Updated electric retail rate forecast

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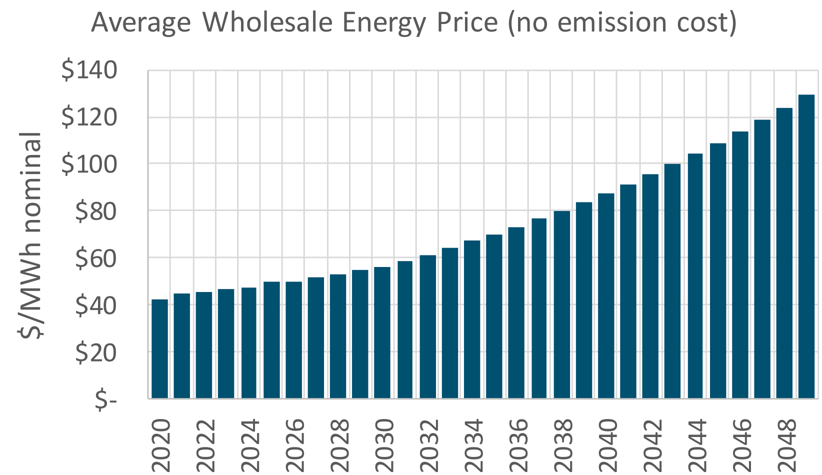
PLEXOS PRODUCTION SIMULATION MODELING

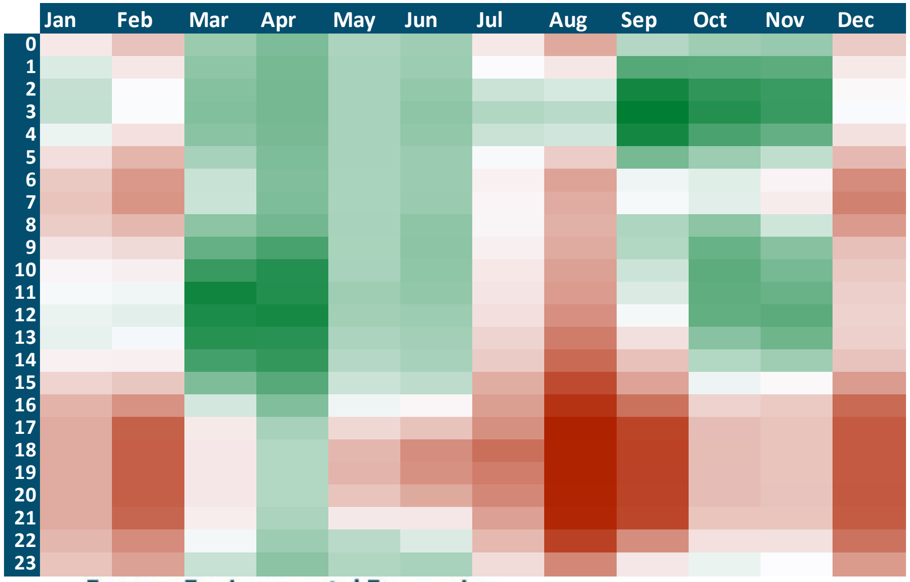
GARRY O’NEILL
ANGELA TANGHETTI

Energy

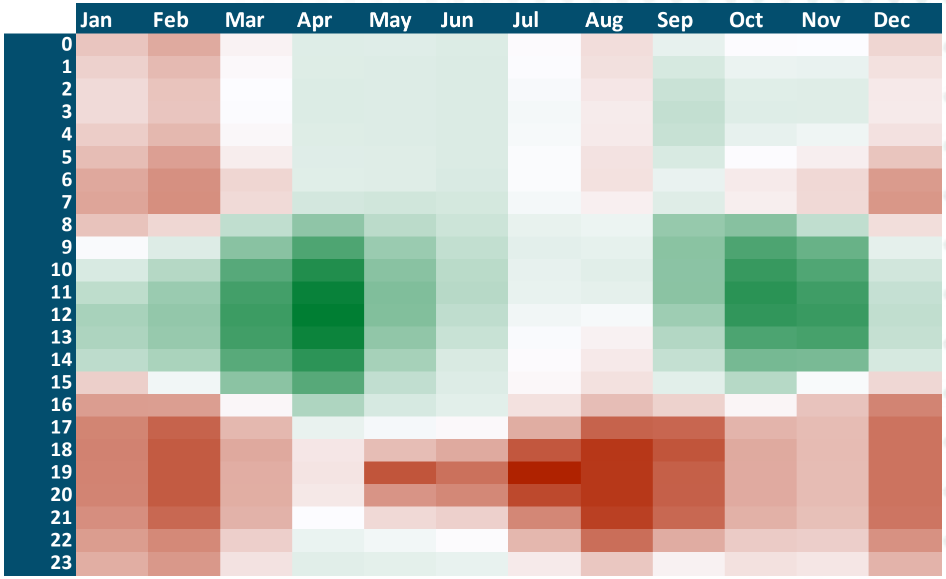
- **Marginal energy price shape generated from PLEXOS production simulation modeling at CEC**
- **50% RPS portfolio calculated with CPUC RPS Calculator**
- **2026-2049 is assumed to have same price shape as 2026**



2020 Shape

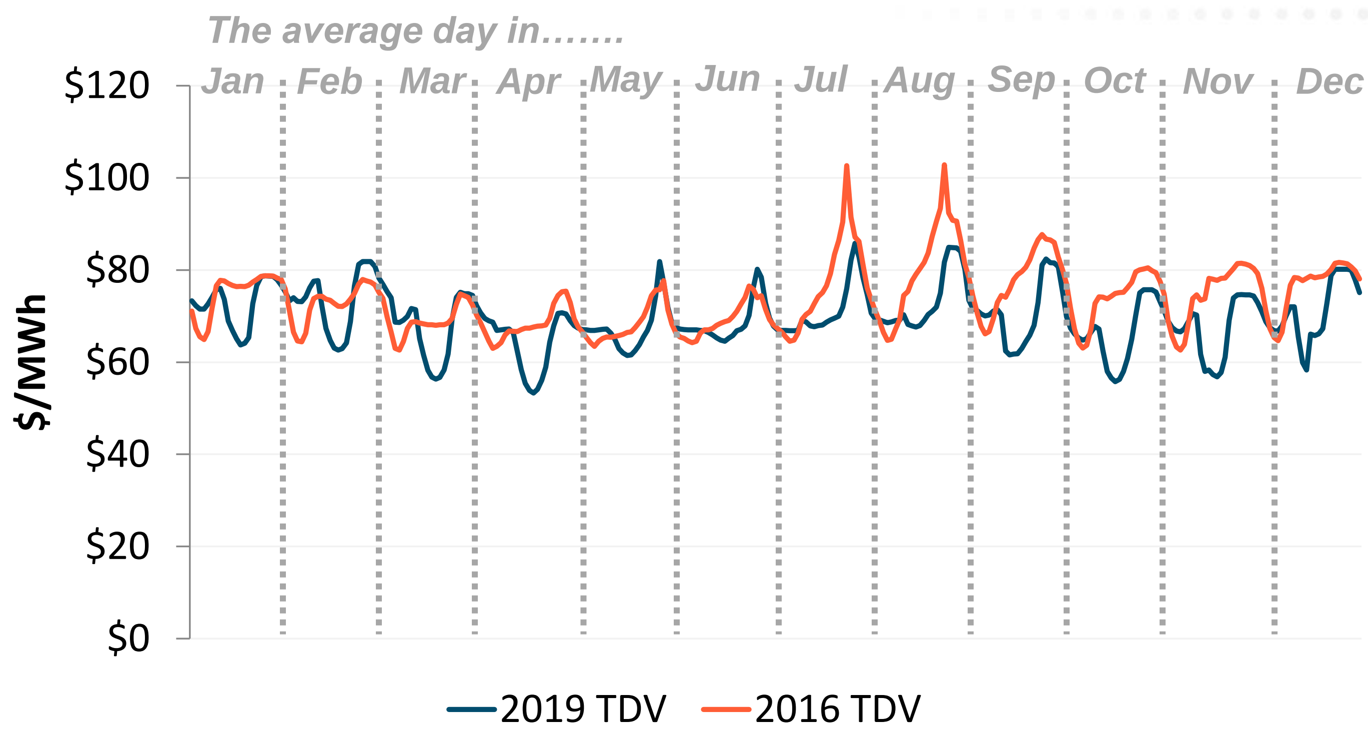


2026 Shape



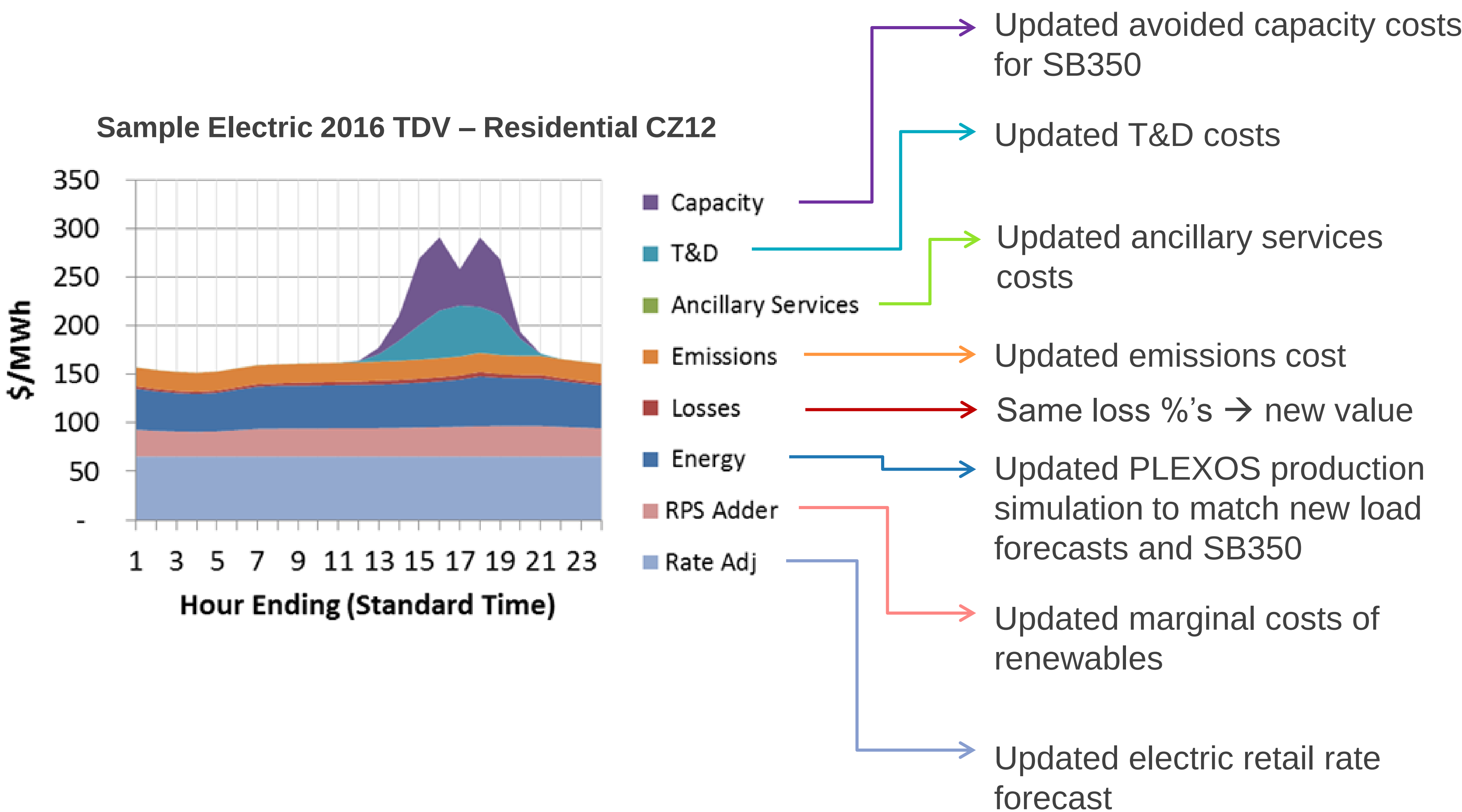
Energy Price Shape Comparison

+ **Updated PLEXOS results begin to show lower mid-day energy prices due to higher RPS and solar penetration**



Updated Inputs to Electricity TDV

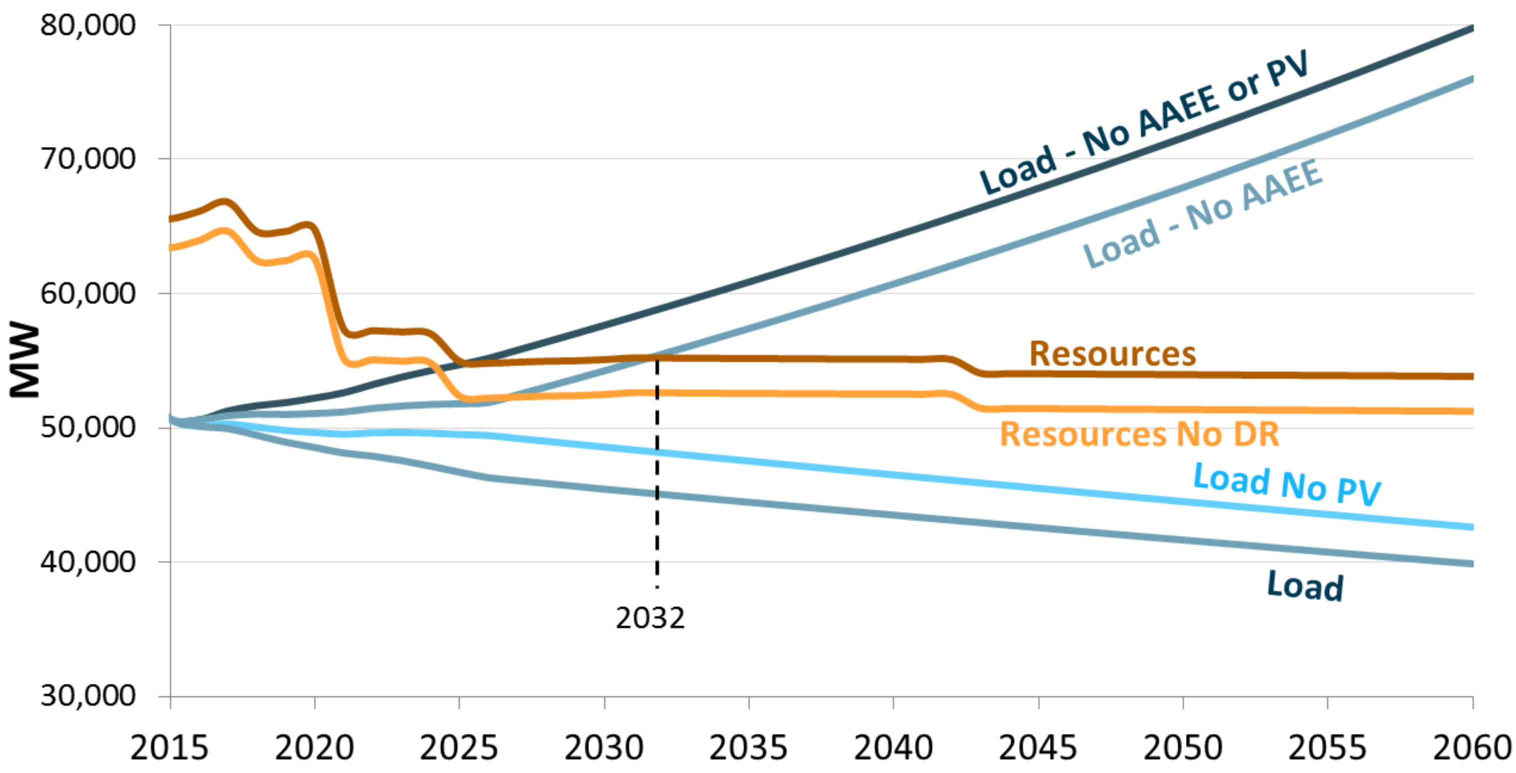
Sample Electric 2016 TDV – Residential CZ12



Generation Capacity (1)

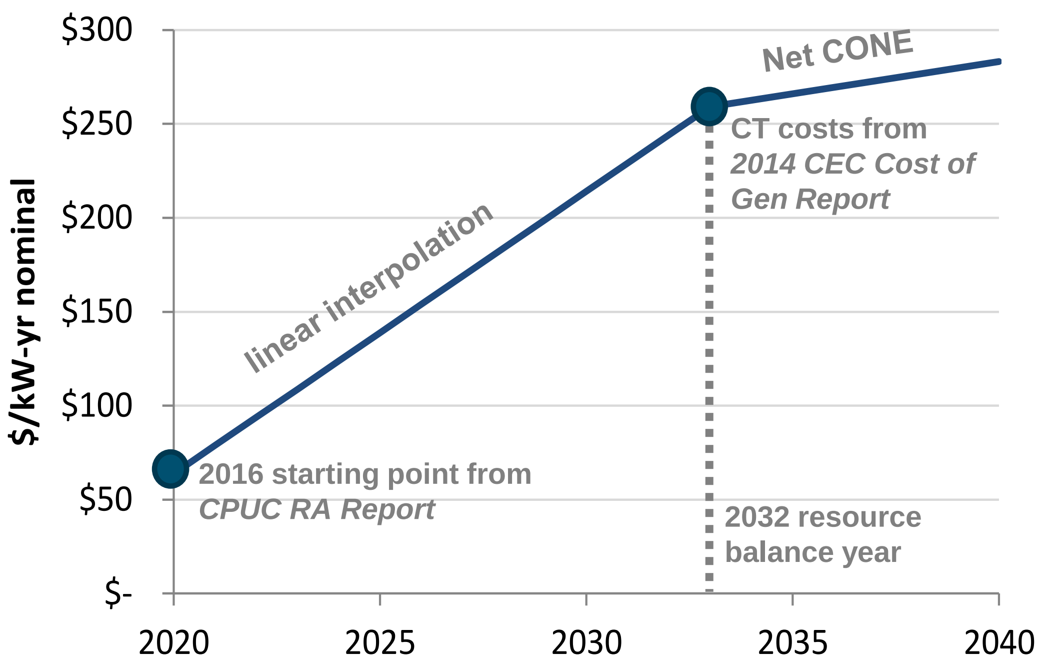
Updated resource balance year

- Expected renewable build extends resource balance year and reduces the value of capacity in the near-term
- Calculated using RPS Calculator (no uncommitted AAEE included in load forecast)



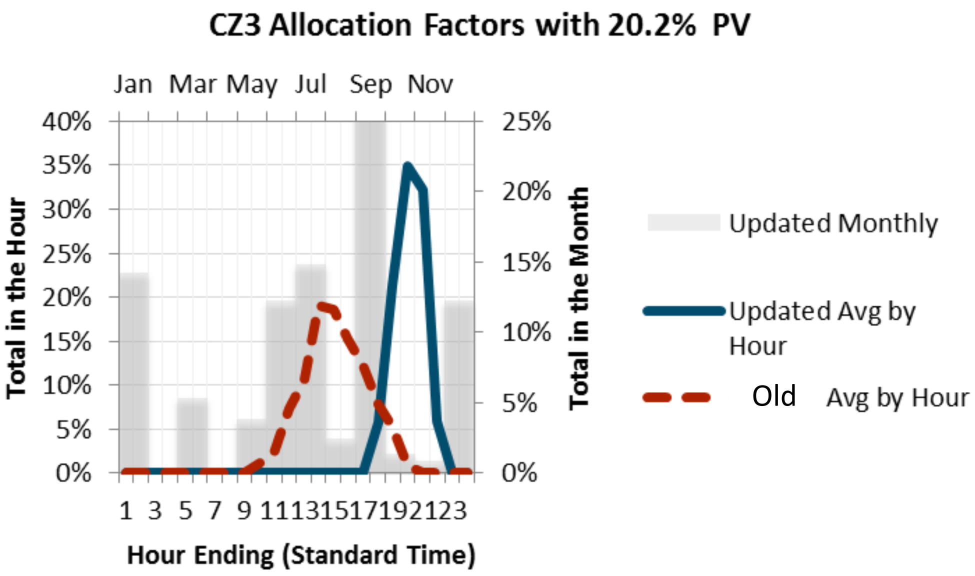
Generation Capacity (2)

+ **Updated capacity value allocation**
  - 50% RPS shifts value to later in the evening and later in the summer
  - Calculated using E3 RECAP model and allocated to hours in TDV weather year



T&D Capacity

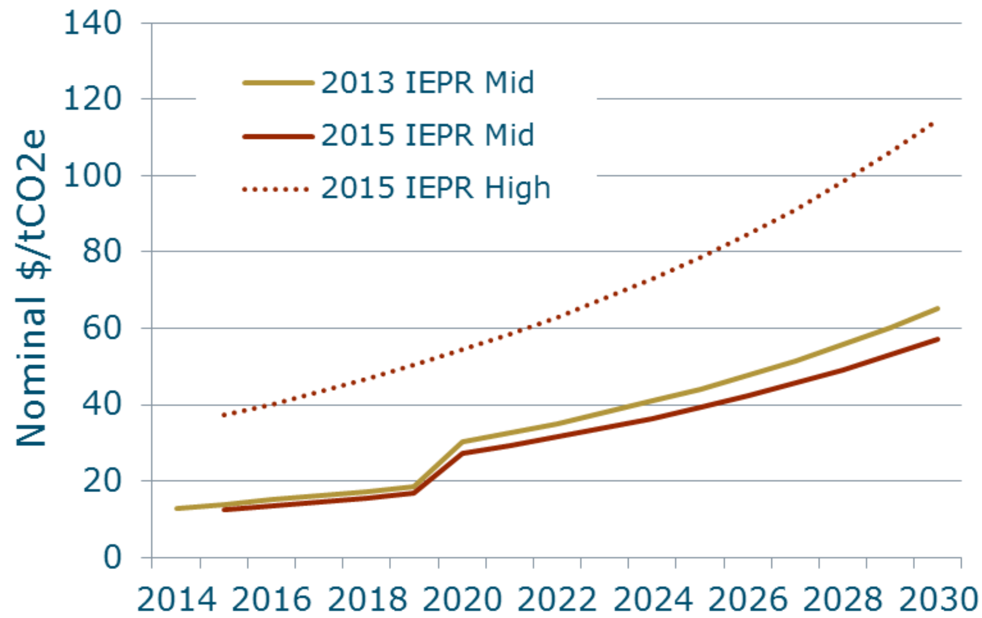
- **T&D avoided costs are calculated using weighted average from the latest utility GRCs**
  - Transmission: $33.63/kW-yr
  - Distribution: $83.99/kW-yr
  - GRC Sources: PG&E 2014, SCE 2015, SDG&E 2015
- **Costs are allocated to climate zones using new methodology of actual utility loads and forecast behind-the-meter PV forecasts**
  - Replaces temperature-only allocation
  - Shifts allocation to later in the evening



Source: E3 regression of PG&E, SCE, SDG&E load data

Ancillary Services, Emissions, and Losses

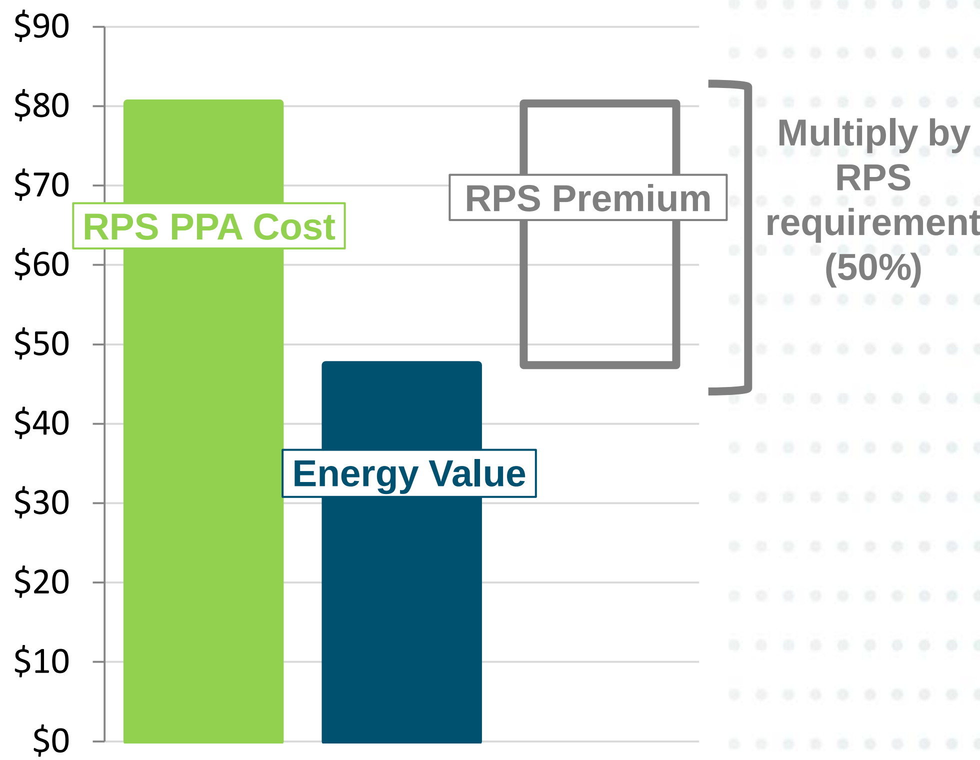
+ **Ancillary Services**
  - Continue to use 0.5% of energy
+ **Emissions**
  - Updated GHG price forecast to 2015 IEPR
  - Continue to calculate marginal emission rate on hourly implied heat rate using energy and gas prices
+ **Losses**
  - Continue to use utility-specific loss factors retained from 2013 TDV analysis



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

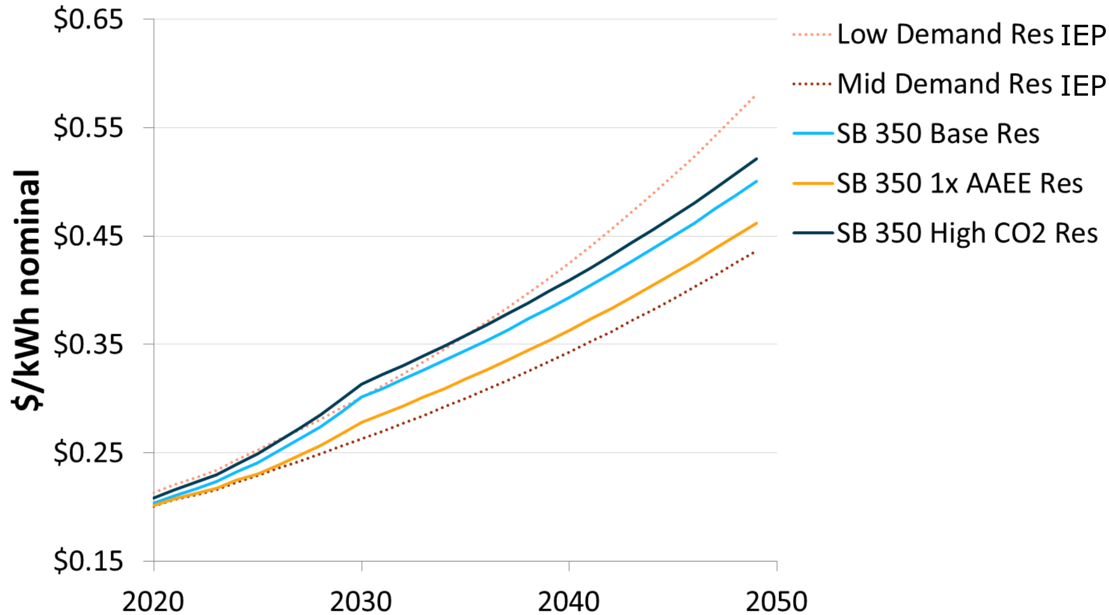
RPS Premium

- **Avoided cost of procuring additional RPS energy**
- **Marginal RPS cost data from CPUC RPS Calculator Version 6.2**
  - Assumed to be energy-only resource with **no** incremental transmission costs and **no** capacity value
- **Decline in RPS costs has decreased this component**
- **NOTE: this component has no effect on the shape of TDV outputs since it is flat – its inclusion simply reduces the retail rate adder**



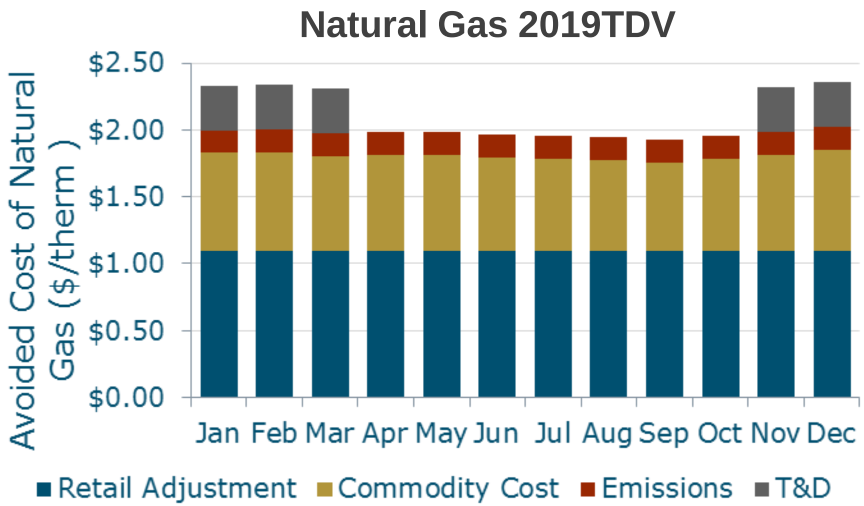
Retail Rate Adjustment

- Retail rate adder is used to ensure that the load weighted average TDVs are equal to customer retail rate
- Mid-Demand and Low-Demand rate forecasts provided by 2015 IEPR
- SB-350 retail rate adjustment was estimated by E3
- Approach
  - CPUC RPS Calculator to calculate average rates under IEPR mid demand and SB 350 friendly assumptions
  - Apply this % impact to the IEPR mid electric rate forecast

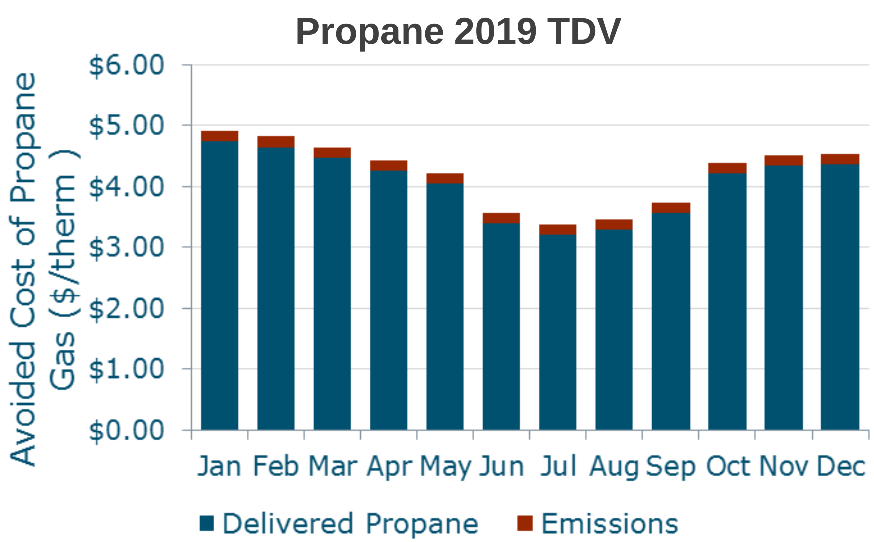


Source: CPUC RPS Calculator, 2015 IEPR

Updated inputs to Natural Gas and Propane TDV



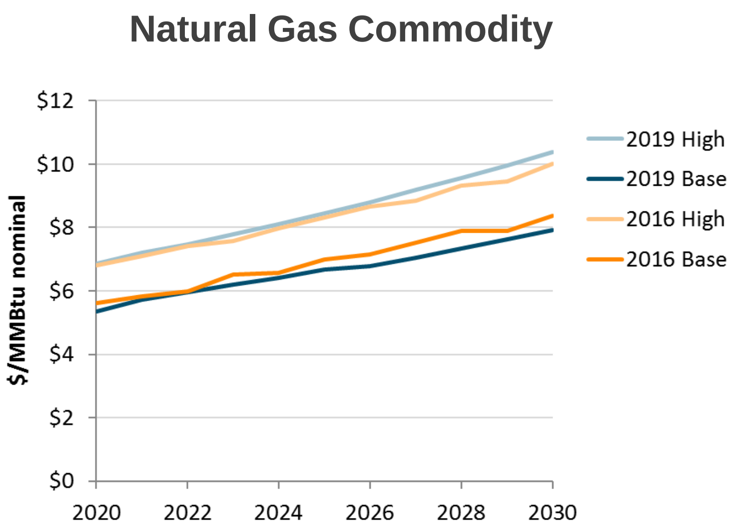
- Updated CO2 price forecast
- Updated Henry Hub price forecast
- Updated natural gas retail rate forecast

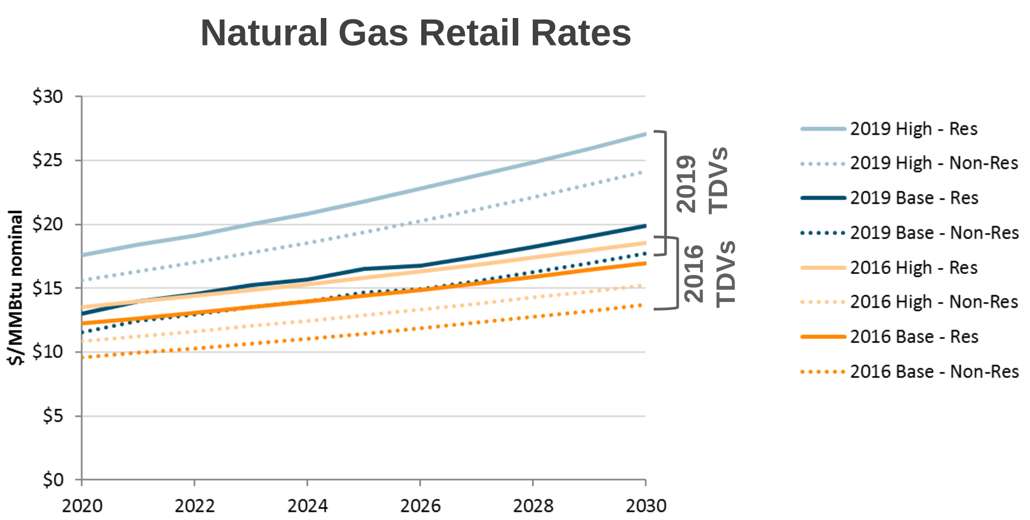


- Updated CO2 price forecast
- Updated propane retail rate forecast

Natural gas and propane retail rate forecasts

- **Natural gas commodity price update**
  - Natural gas burnertip price forecast from 2015 IEPR
- **Natural gas retail rate price update**
  - Retail rate forecast from 2015 IEPR





- **Propane price forecast**
  - EIA AEO 2013 Pacific region forecast, normalized to IEPR through natural gas rates – Propane $Price_{EIA}$*(NG $Price_{IEPR}$/NG $Price_{EIA}$)

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DRAFT TDV RESULTS

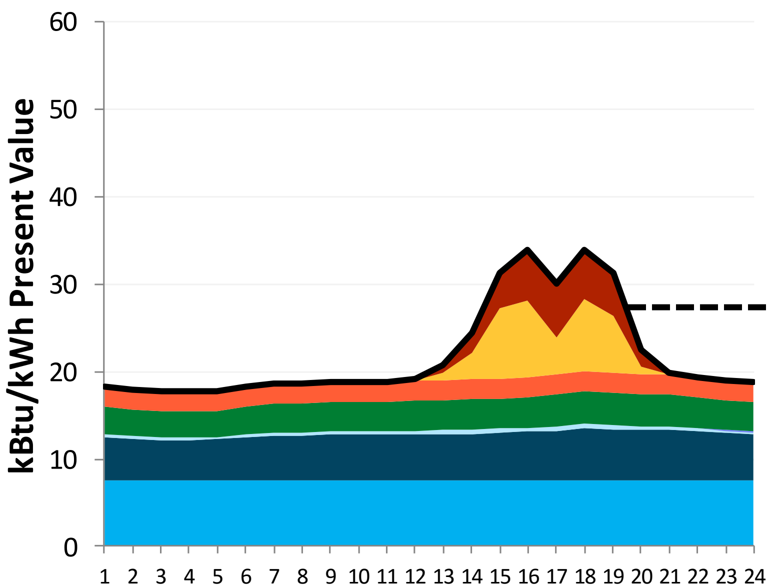
Changes in TDVs from Last Cycle

- Increase in retail rate forecast drives average TDV level higher
- Generation capacity and T&D capacity have shifted to later in evening

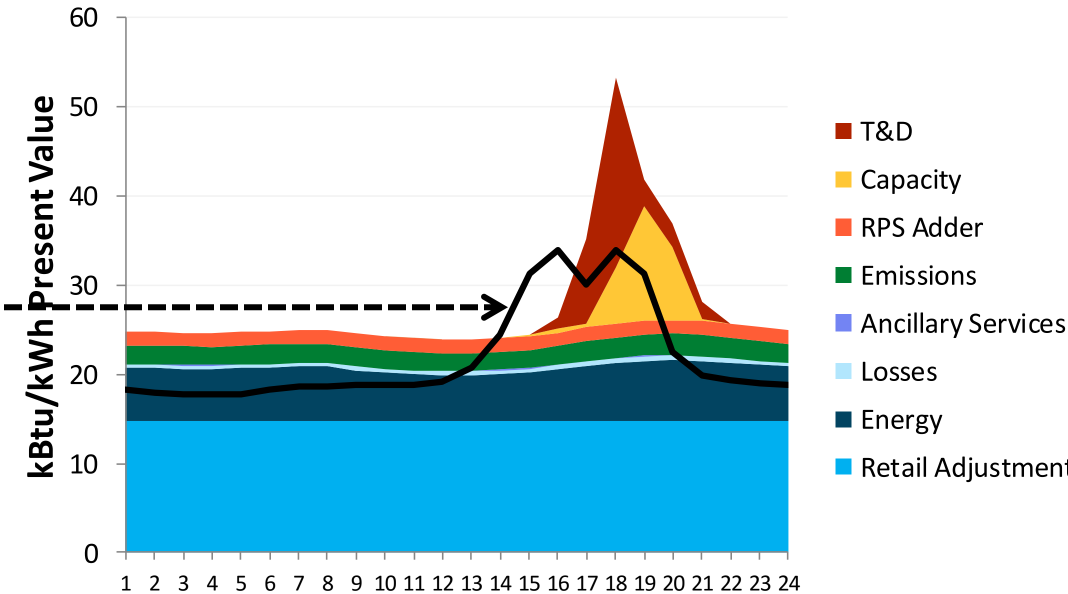
Res (30-yr)	Electric (kBtu/kWh)	Gas (kBtu/therm)	Propane (kBtu/therm)
2019 Avg TDV	27.7	217.1	430.2
2016 Avg TDV	21.9	165.1	323.4
% Change	+27%	+32%	+33%

Non-Res (15 yr)	Electric (kBtu/kWh)	Gas (kBtu/therm)	Propane (kBtu/therm)
2019 Avg TDV	27.6	197.8	365.2
2016 Avg TDV	20.7	142.7	276.6
% Change	+33%	+39%	+32%

2016 Electric TDVs*

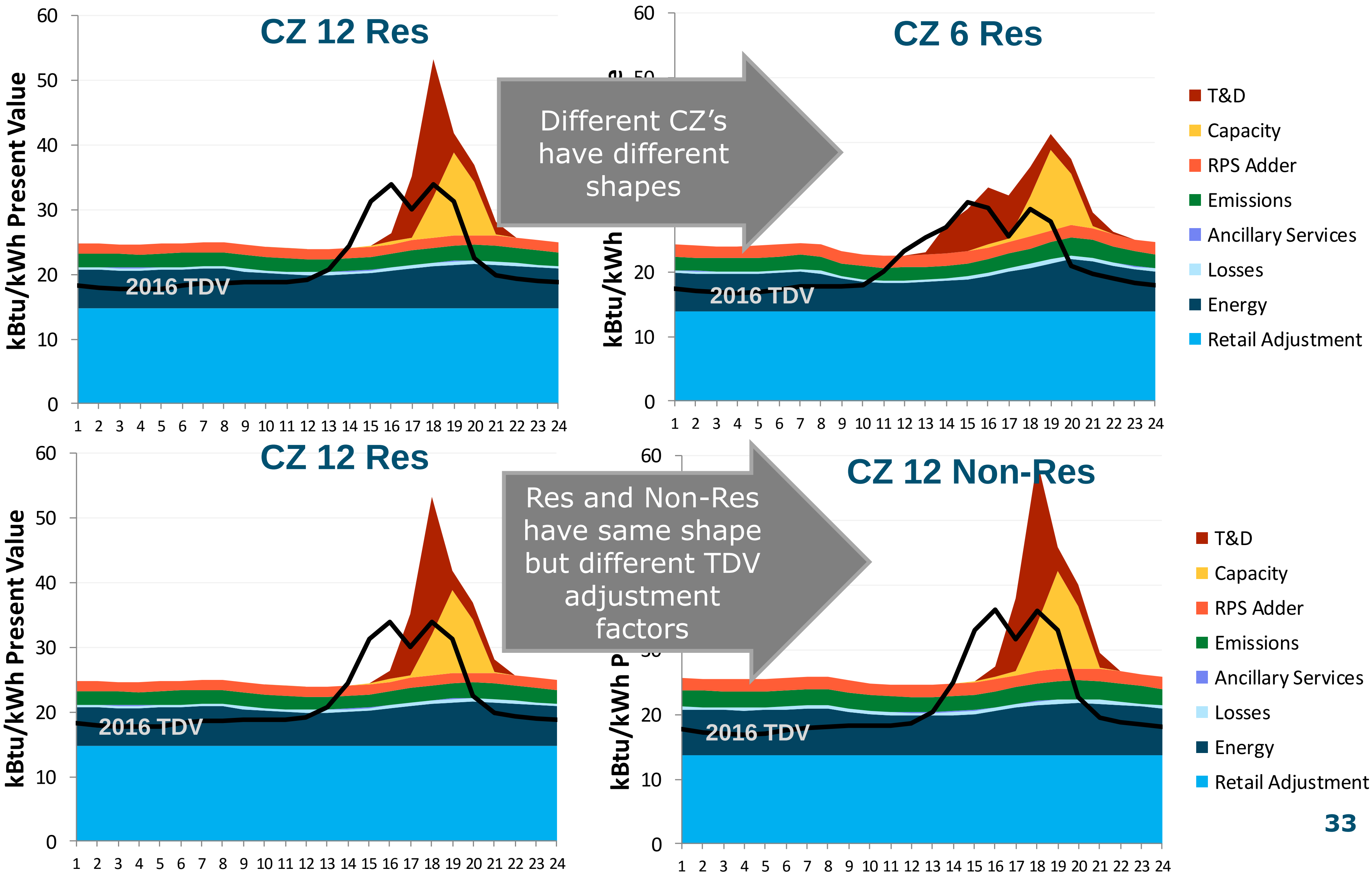


2019 Electric TDVs*

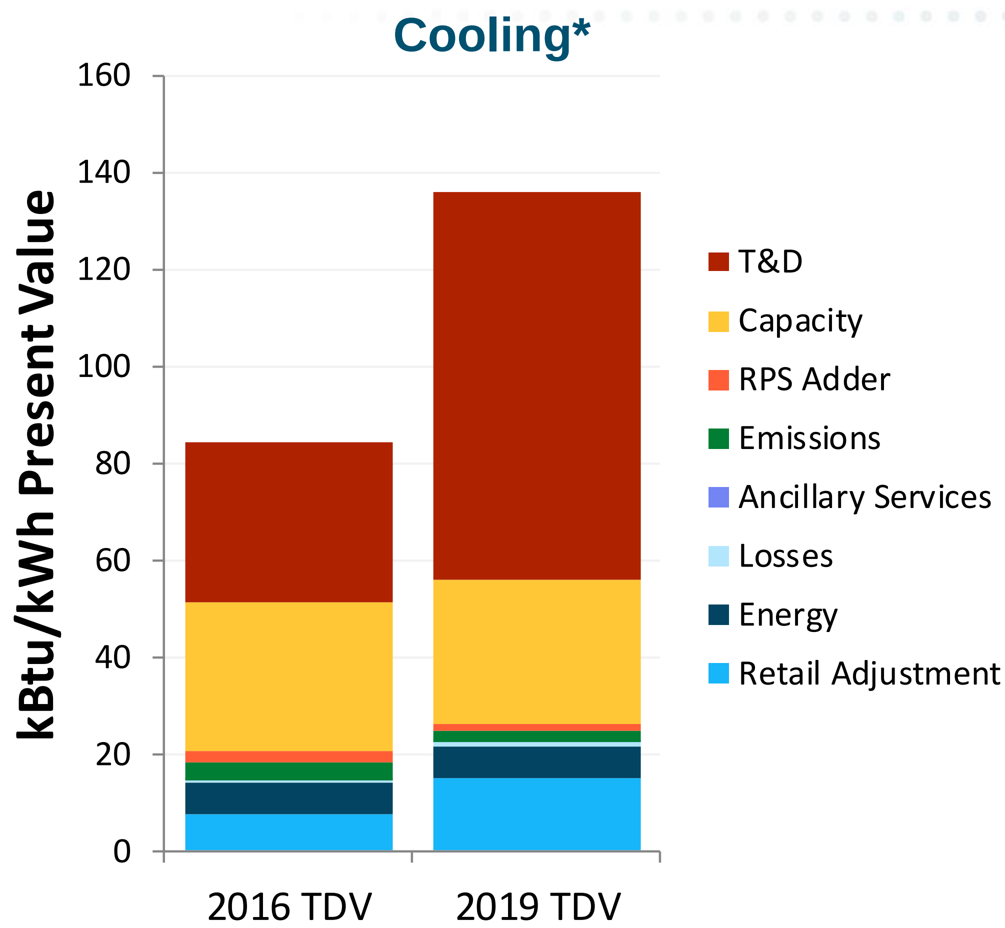


*CZ 12 Residential 30-Yr Present Value

Comparisons between TDVs



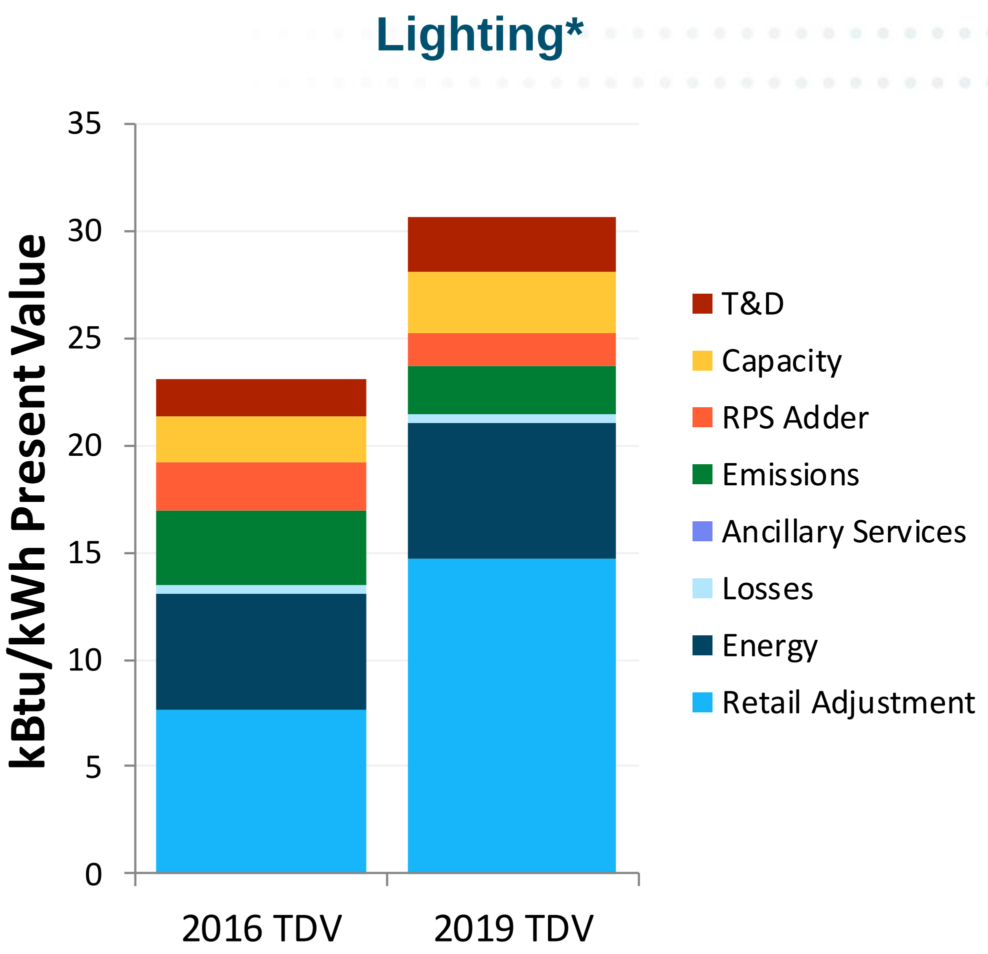
- Larger T&D capacity deferral value coupled with better coincidence with cooling loads drive increase in TDV value
- Shift of generation capacity value into evening reduces value
- Retail rate increase drives some TDV value increase



*CZ 12 Residential 30-Yr Present Value

Impact on Electric End Uses
Lighting

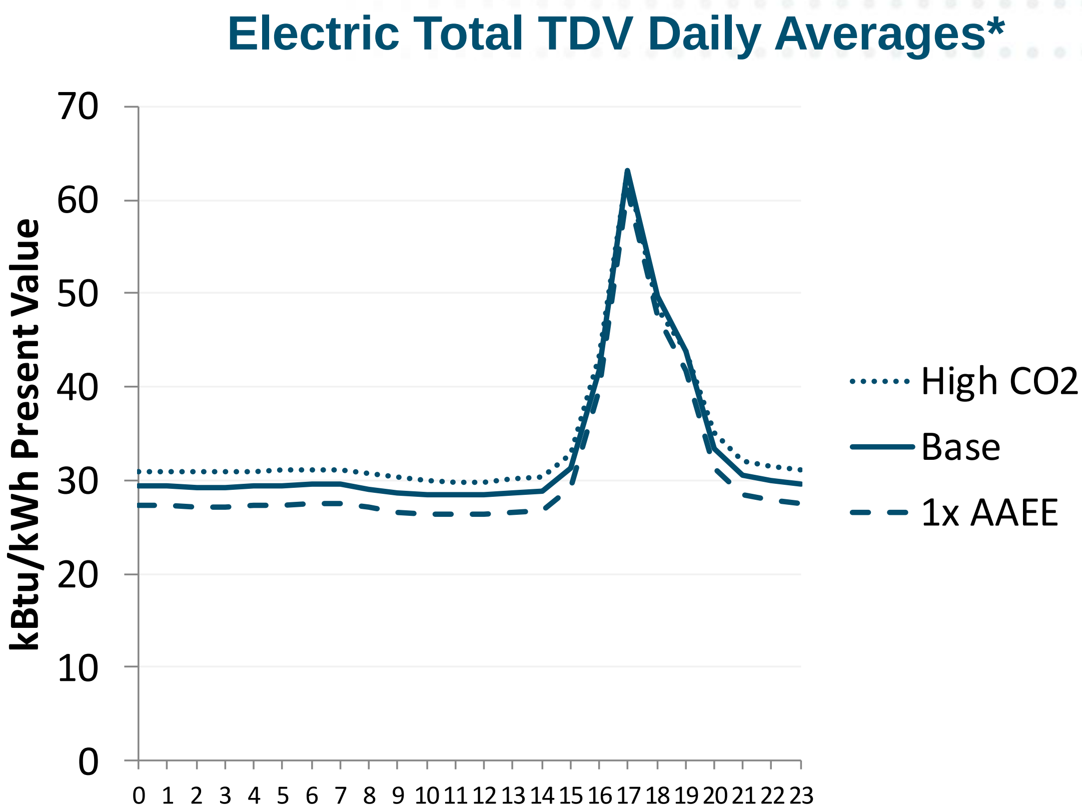
- Increase in retail rates drives large portion of lighting TDV value increase
- Better coincidence of generation capacity and T&D capacity value and lighting load shape drive increase in total TDV value



*CZ 12 Residential 30-Yr Levelized

Scenario Analysis

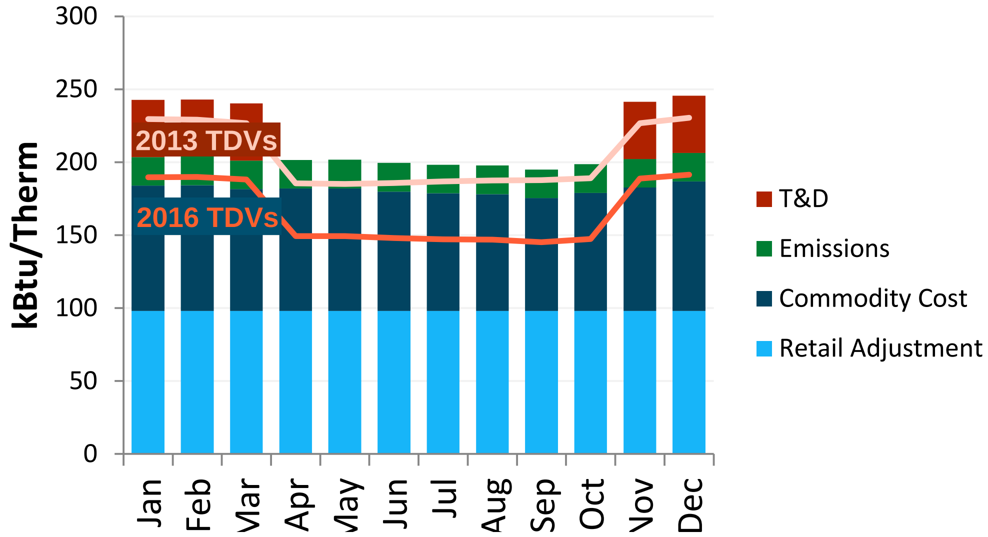
- **Differences between scenarios are largely driven by resultant retail rate forecasts**
- **High CO2**
  - CO2 price drives up retail rate because California GHG household credit is not tied to electricity consumption
- **1x AAEE**
  - Less efficiency means fixed costs can be spread over more retail sales which results in lower rates

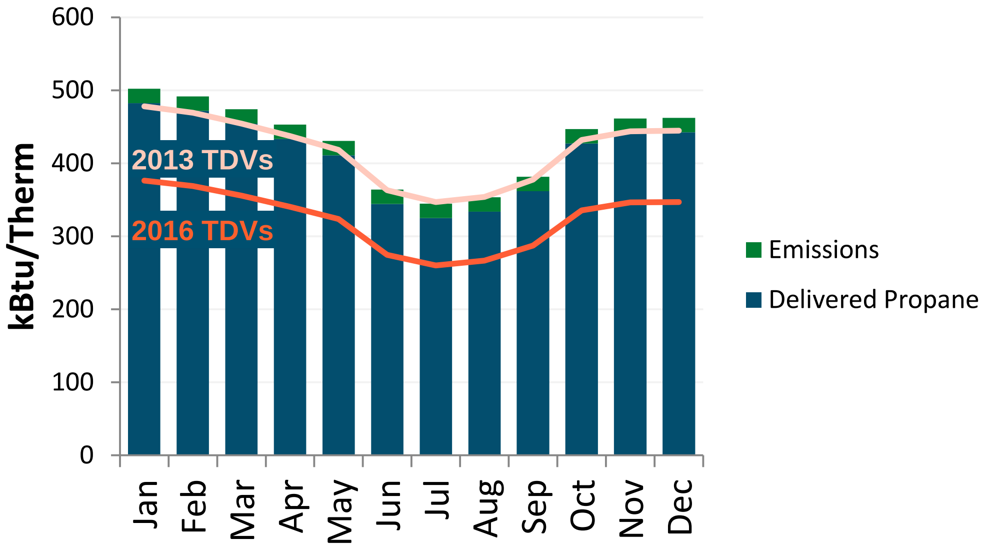


*CZ 12 Residential 30-Yr Present Value

Natural Gas and Propane TDVs

+ **Natural gas and propane both increase in TDV value due to increase in natural gas retail rate forecast**





*Residential 30-Yr Present Value