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Valley Clean Energy Alliance

2021 Demand Forecast Methodology

Submitted

April 13, 2021

Forecast Process

The method used for the 2021 VCEA Demand Forecast submittal is described in the 8 steps listed below. Note that VCEA's 2021 resource adequacy forecast is equal to year 2021 of the demand forecast.

1. Process Historical Customer Interval Meter Data

The VCEA demand forecast begins by evaluating historical retail meter interval data provided from PG&E as "Item 17" data. For this forecast, interval data for the period 2016 - 2020 was analyzed.

2. Develop Average Customer Load Profiles by Rate Class

For the interval data history, customer counts varied over the period for two reasons:

1. The interval data set did not contain 100% of all PG&E customers in the VCEA territory, and for any given customer, a complete time series of interval data across the historic period may not have existed;
2. Customer growth: generally over the period, customer counts increased due to new locations taking electric service.

For the five-year period of interval data history, for each rate class, average per customer loads were developed by dividing the total load for each rate class by the number of customers in that rate class to develop an average hourly load per customer/per class load profile.

Specifically, for the 2016 – 2017 interval data, for each rate class, per customer hourly loads were determined using all load data for all PG&E customers in the VCEA service area. For 2018-2020, for each rate class, the per customer VCEA loads were developed using a subset of the Item 17 interval data from PG&E, filtered based on VCEA customers as identified in the customer information data provided by PG&E ("4013" data) as of the end of the year. Service account information for VCEA customers from the 4013 report was used to match to the interval data. For customers on net metering, the per customer VCEA load was developed using a weighted average of VCEA and PG&E interval load data to account for customer migration from PG&E to VCEA. This was necessary in order to have a relatively stable historical data for use in load forecasting.

Customers were categorized by rate class using PG&E's ERRA rate class categories. Table 1 below shows those categories.

Table 1. PG&E Rate Classes

Residential (Non TOU)
Residential TOU
Small Commercial (Non TOU)
Small Commercial TOU
Medium Commercial
Street Lighting
Traffic Control
Agricultural
E19 S (Large Commercial/Industrial, Secondary Voltage Service)
E19 P (Large Commercial/Industrial, Primary Voltage Service)
E20 P (Very Large Commercial/Industrial, Secondary Voltage Service)
E20 S (Very Large Commercial/Industrial, Primary Voltage Service)

Rate classes were further split into enrolled VCEA customers versus eligible customers on net energy metering prior to VCEA's launch. The Winters customers are assumed to have similar load shapes to the existing VCEA customer base and are mass enrolled in January 2021. There are also a small subset of customers moving from VCEA to direct access in January 2021.

3. Weather Normalize the Load Profiles by Rate Class (Weather Adjustments)

The load profiles were weather normalized by developing regression models for each rate class. The weather variables included daily cooling degree days (CDDs) with base temperatures of 65°F, 70°F, and 75°F, heating degree days (HDDs) with base temperatures of 65°F and 60°F, and a non-linear weather response "s" shaped curve for daily high temperatures above 90 degrees Fahrenheit. Daily lagged HDDs and CDDs variables were also specified in the regression models to account for the thermal mass in the building shell.

A daily weather pattern for the forecast expected weather conditions was then developed. Weather data for the VCEA service area comes from the Sacramento International Airport. Daily high and low temperatures are available from the NOAA FTP web site. To develop the normal weather temperature pattern, daily high and low temperatures from 2000 through 2019 were ranked and averaged by month and arranged on the calendar by average monthly temperature to produce a normal weather year. A heat wave was placed in July during the weekdays to create a peak simulation.

The normal weather pattern is then applied to the regression models for each rate class to obtain the 8,760 hour per customer load shape.

4. Forecast Customer Growth by Rate Class (Economic and Demographic Data)

The actual and forecasted economic and demographic data were produced by the Sacramento Area Council of Governments (SACOG)[1] and the California Department of Finance (DOF).[2] The SACOG information included area population, housing and jobs forecasts disaggregated into the Davis, Woodland and unincorporated Yolo county areas. The SACOG economic and demographic forecasts were developed at the parcel level for SACOG's 2016 Metropolitan Transportation Plan and Sustainable Community Strategy. The forecasted data was last updated in May 2018. The demographic forecast by DOF included data on population, households, and group quarters for Yolo county. The DOF forecast was last updated in June 2020.

The table below shows the population, housing and jobs forecast for the VCEA service territory.

Table 2A. Growth Rates for VCEA Service Area (SACOG)

Forecast Factor	2012 Actual	2036 Forecast	Annual Growth Rate, %
Population	144,539	178,115	0.9%
Housing	54,304	64,498	0.7%
Jobs	65,153	87,251	1.2%

Table 2B. Growth Rates for VCEA Service Area (DOF)

Forecast Factor	2015 Actual	2030 Forecast	Annual Growth Rate, %
Household Population	202,501	223,555	0.66%

The starting point for the customer forecast was based on the number of VCEA customers from the PG&E 4013 report as of January 15, 2021. This report listed both the VCEA and non-VCEA (PGE bundled service or direct access) customers in the VCEA service territory. For VCEA customers, the growth rates were applied to the January 2021 customer count to produce the customer forecast from 2021 to 2032.

[1] For additional information, see SACOG Data Library, City and County Profiles, Updated May 2018, https://www.sacog.org/data-library
[2] For additional information, see P-4: State and County Projected Households, Household Population, and Persons per Household 2020-2030, Updated June 2020, https://www.dof.ca.gov/Forecasting/Demographics/Projections/

The updated household population annual growth rate of 0.66 percent from DOF was used to forecast the number of customers for the residential, streetlights and traffic signal rate classes. The annual jobs growth rate of 1.2 percent from SACOG was used to forecast the number of customers for the small, medium, and E19S customer classes.[3] The jobs growth rate was adjusted downward for forecast year 2021 to reflect COVID related uncertainty.

The customer counts in the E19P, E20S, E20P, and agriculture rate classes was kept constant at their 2020 levels due to lack of information and uncertainty regarding their growth over the forecast period.

Customer counts were adjusted monthly to produce a monthly forecast of customer counts over the forecast horizon.

5. Apply Rate Class-Specific Customer Load Profiles to Customer Forecasts

The modeled/normalized per customer rate class-specific load profiles were applied to the rate class-specific customer forecasts to develop the hourly retail load forecast by rate class. Results from rate class-specific regression models were analyzed to isolate and further model response to the COVID-19 pandemic. Residuals from regression models were analyzed to determine response to closures by rate class and incorporated into the final regression model as appropriate. For some rate classes, the remaining response to COVID-19 closure in the later part of 2020 is assumed to continue into the first half of 2021. The impact is assumed to be reduced in the 2nd half of 2021 and further reduced in 2022. For 2023 and beyond, all COVID-19 impacts were removed.

6. Apply Residential Time-of-Use (TOU) Adjustment

Existing Residential customers, not already on a Time-of-Use (TOU) rate, will be move to the Res TOU rate class starting in February 2022. Most customers will transition in February with NEM customers transitioning as their True-Up bills occur over the course of the year. Low-income (CARE) customers will not need to transition and may remain in the Residential rate class. Based on a review of CARE and non-CARE customer counts and usage, the following assumptions were made for the load forecast:

- 95% of CARE customers will remain in their current (non-TOU) residential rate
- 24.3% of the current (non-TOU) residential rate customers will remain in that rate class

[3] DOF economic data and projections were only available at the statewide level and so were not used for forecasting growth in VCEA service area non-residential accounts. Given the lack of updated publicly available data to forecast the growth in non-residential customer counts, the growth rate from the 2020 filing was retained and used for the 2021 filing.

- 26.2% of the current (non-TOU) residential rate load will remain in that rate class (the average CARE customer uses more energy than the average non-CARE customer)

Based on a PG&E study, the following shift in load was assumed. This shift was only applied to those customers moving from the non-TOU residential rate class to the TOU residential rate class starting in 2022. The load shift only applies to summer (June-September) and the only holidays are Independence Day and Labor Day.

Table 3. Residential TOU Load Shift

time	HE	Weekday	Weekend/Holiday
mid-1am	1	0.0%	0.0%
1am-2am	2	0.0%	0.0%
2am-3am	3	0.0%	0.0%
3am-4am	4	0.0%	0.0%
4am-5am	5	0.0%	0.0%
5am-6am	6	0.0%	0.0%
6am-7am	7	0.0%	0.0%
7am-8am	8	1.0%	1.5%
8am-9am	9	3.0%	2.5%
9am-10am	10	4.5%	3.5%
10am-11am	11	5.0%	3.0%
11am-noon	12	4.5%	3.0%
noon-1pm	13	2.5%	1.0%
1pm-2pm	14	0.0%	0.0%
2pm-3pm	15	0.0%	0.0%
3pm-4pm	16	0.0%	0.0%
4pm-5pm	17	-4.5%	-3.5%
5pm-6pm	18	-5.5%	-4.0%
6pm-7pm	19	-5.5%	-4.5%
7pm-8pm	20	-5.5%	-4.0%
8pm-9pm	21	-4.5%	-3.5%
9pm-10pm	22	0.0%	0.0%
10pm-11pm	23	0.0%	0.0%
11pm-mid	24	0.0%	0.0%

7. Make Additional Adjustments for Net Metered Solar Installations and Plug-In Electric Vehicle Charging Loads

Growth in two known load/usage modifiers were separately modeled in this load forecast: 1) Net energy metered solar installations in residences and 2) Plug-in electric vehicle adoptions and the charging load impacts. Each is described in detail in sections below. Due to uncertainty, no additional growth for other distributed energy resources or building electrification is planned.

8. Apply Distribution Losses

Up to this point in the process, all loads forecasted are retail loads as measured at the customer meters. Monthly distribution loss factors were applied to the hourly loads to develop a “wholesale” load, excluding transmission losses.

PG&E provides historical hourly distribution loss factors for primary and secondary voltage service customers. Hourly loss factor data for 2017 – 2020 were pulled and averaged to create monthly factors by service level voltage. The percentage of VCEA load forecast to be served for secondary and primary service level voltages was then applied to the factors to develop a composite monthly factor. The factors are shown in Table 3 below.

Table 4. PG&E Distribution Loss Factors

Month	Primary Voltage DLF	Secondary Voltage DLF	Weighted Composite Distribution Line Loss
% on voltage level	5%	95%	100%
1	1.018275477	1.067266438	6.476%
2	1.018116219	1.066979909	6.448%
3	1.017651795	1.066302818	6.381%
4	1.017452004	1.066054674	6.356%
5	1.018136666	1.06718161	6.467%
6	1.020114517	1.070889048	6.829%
7	1.021302517	1.073282968	7.062%
8	1.021508078	1.073695396	7.102%
9	1.019954902	1.070502926	6.791%
10	1.018520637	1.067828334	6.530%
11	1.017871723	1.066605302	6.411%
12	1.018289515	1.067263503	6.475%
Average Annual	1.0189328375	1.0686544104	6.611%

The weighted composite monthly distribution line losses were then added to the hourly retail load forecasts to obtain hourly wholesale loads.

Additional Mass Enrollments

Approximately 2,740 customers in the Winters area will be added to the VCEA territory. They will be added in January 2021 with the exception of residential NEM customers. Residential NEM customers will be added to VCEA territory monthly in 2021 based on their NEM true-up schedule.

Customer Migration/Opt-Outs

For the VCEA forecast, opt-out rates are implicitly assumed to remain at the current opt-out percentages, by rate class. No explicit opt-out percentage is applied to customer growth assumptions because customer growth for the VCEA forecast is applied to the base of existing VCEA customers (that excludes customers who have opted out).

New Net Energy Metered Distributed Generation Adoption

VCEA's service area has a high adoption rate of net energy metered (NEM) solar installations. From January 2019 to January 2020, 2,794 residential customers in VCEA's service area installed net energy metered distributed generation at existing service locations. We extrapolated that growth into the future and assumed that one-half of new all VCEA customers would install net energy metered solar for each month of the forecast horizon. To simplify the modelling, it was assumed that these installations would mostly be in residences including the TOU participants.

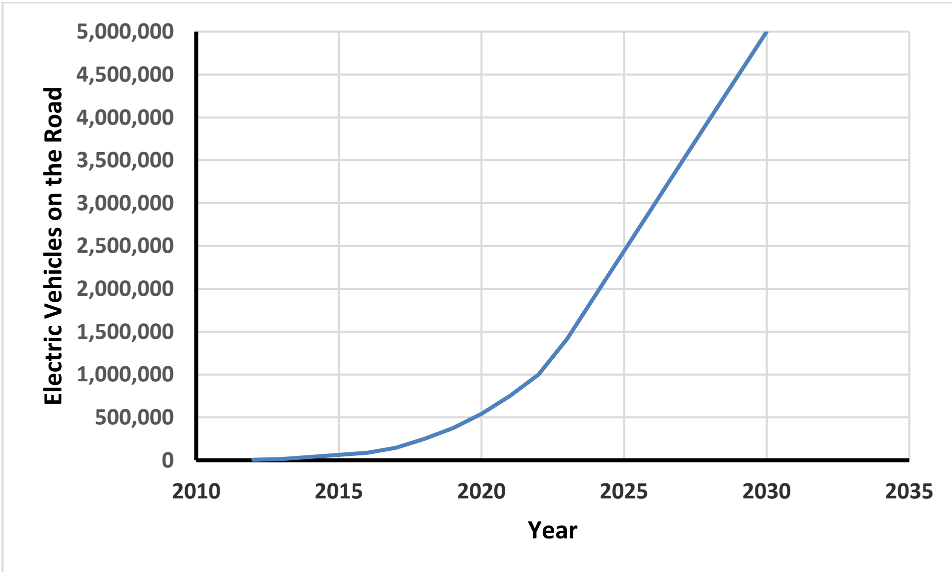
The number of NEM customers are forecasted separately by month. Current and future NEM customers spread among all customer classes except traffic control and street lighting. A separate regression analysis is conducted for each NEM class using historical metered data from 2016 to 2020. The analysis uses an estimated hourly PV generation in the regression equation to improve the accuracy of the estimation and forecast. The resulting forecast of each NEM subclass is then combined with the forecast of the corresponding non-NEM customer subclass to produce the complete forecast by class. For example, the forecast of Residential (non-NEM) plus the forecast of Residential NEM customers make the total Residential class forecast.

Plug-In Electric Vehicle Charging Loads

Adoption of electric vehicles (EVs) is increasing. Over time, we expect the vehicle charging loads to be significant. The California Air Resources Board, in its 2017 Climate Change Scoping Plan[4] identified a statewide target of needing 5 Million electric vehicles on the road in order to meet 2030 carbon emission reduction goals. To convert that goal into an EV forecast, we developed an adoption curve for statewide EV counts from 2010. That curve is shown in Chart 1 below.

[4] *California's 2017 Climate Change Scoping Plan, The Strategy for Achieving California's 2030 Greenhouse Gas Target*, California Air Resources Board, November 2017, https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf

Chart 1. Statewide EV Adoption Curve



To convert the statewide forecast to an EV adoption forecast for VCEA, the number of statewide vehicle adoptions were prorated to VCEA using comparisons of current (January 2018) population statewide, versus population in VCEA's service area. 0.40% of the state's population resides in VCEA's service area.

EV counts were then applied to residential EV charging curves developed by NREL, as published in the California Energy Commission's report on plug-in electric vehicle charging infrastructure[5]. To simplify modelling, we assumed all charging would be done in residences, which has an evening/nighttime weighted charging shape. The charging shapes for the weekend is different than that for the weekdays.

Forecasting results for EV are embedded in Residential (non TOU) and Residential TOU rate classes, based on the proportion of monthly customer counts in each rate class.

Load Loss to Direct Access

Regarding CPUC Decisions 19-05-043 and 19-08-004, a load loss starting in 2021 is expected. These customers were identified and removed from the customer count for their respective classes starting in 2021.

[5] California Plug-In Electric Vehicle Infrastructure Projections: 2017-2025, Future Infrastructure Needs for Reaching the State's Zero-Emission-Vehicle Deployment Goals, California Energy Commission, March 2018, CEC-600-2018-001, https://www.nrel.gov/docs/fy18osti/70893.pdf

Energy Efficiency and Demand-Side Management

In this load forecast, we did not attempt to model the impacts of future energy efficiency and demand-side management programs, as those programs are currently managed by PG&E. VCEA does not have enough information on those programs or their estimated impacts to properly factor them into this 2021 forecast.

Climate Change and Electrification

The impacts of climate change were not modelled in this VCEA 2021 forecast. To do so would require a model of how local weather and daily temperatures would change, in order to construct a “normal” weather profile with increasing average temperatures going forward in time.

Apart from vehicle electrification, the possible future impacts of other electrification, such as space and water heating, were not modelled.