VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 10

TO: Community Advisory Committee

FROM: Gordon Samuel, Assistant General Manager & Director of Power Services

SUBJECT: VCE Load and Power Costs Forecasting

DATE: April 28, 2022

Load Forecasting Methodology

The attached document outlines the approach VCE uses to produce the load forecast. This final load forecast, which is updated annually, has multiple uses including but not limited to: informing VCE's energy, resource adequacy (RA), and renewable portfolio standard position as well as multiple regulatory filings.

Attachment

1) "2022 Integrated Energy Policy Report Electricity Demand Forecast Filling: Form 4 – Demand Forecast Methodology"

Valley Clean Energy Alliance

2022 Integrated Energy Policy Report

Electricity Demand Forecast Filling

Form 4 – Demand Forecast Methodology

Submitted

March 31, 2022

Forecast Process

The method used for the 2022 VCEA IEPR Electricity Demand Forecast submittal is described in the 8 steps listed below. Note that VCEA's 2023 resource adequacy forecast is equal to year 2023 of the IEPR 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 - 2021 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 2018-2021, 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.

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. For the Agriculture rate class only, precipitation is a driving factor in usage. Last year was a drought year and that drought is expected to continue into this year (2022) so a drought indication was used resulting in higher expected Agriculture demand in 2022 with a return to normal precipitation in subsequent years.

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]. 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 2020 Metropolitan Transportation Plan and Sustainable Communities Strategy (MTP/SCS). The forecasted data was last updated in May 2021. The forecast of jobs growth from SACOG's 2016 MTP/SCS report was retained for this forecast based on validation with other sources of data.[2]

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

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

Forecast Factor	Annual Growth Rate, %
Population	0.72%
Housing	0.8%
Jobs	1.2%

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, 2022. 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 2022 customer count to produce the customer forecast from 2022 to 2035.

The updated household population annual growth rate of 0.88 percent from SACOG 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. The jobs growth rate was adjusted downward for forecast year 2022 to reflect COVID and economic related uncertainty.

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[1] For additional information, see SACOG 2020 MTP/SCS Modeling Projections for 2016 and 2040, https://www.sacog.org/post/sacog-2020-mtpscs-modeling-projections-2016-and-2040
[2] For additional information, see SACOG Data Library, City and County Profiles, Updated May 2018, https://www.sacog.org/data-library

The customer counts in the E19P, E20S, E20P, and agriculture rate classes was kept constant at their 2021 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 and calibrated to the settlement data.

Depending on the individual rate classes, assumptions of COVID-19 during certain periods in 2020-2021 are included in the regression models to account for the load impact triggered by altered customer behaviors\usage due to COVID-19.

For the non-NEM customers, Residential, Small, Small TOU, Medium, and E19S rate classes have COVID-19 assumptions during periods in 2020-2021 where the comparison of before and after COVID-19 periods shows noticeably declined or increased in average customer’s load. This comparison is based on a forecast estimation up through 2019 and with the prediction for 2020-2021. These rate classes also include a trend variable for 2021 as the basis for subsequent years’ trend in the forecast.

For NEM customers, only the Residential class has specific COVID-19 assumptions during the periods in 2020-2021 to account for any inter-year anomalies not accounted for in the annual trend variables. NEM customers have the added challenge of PV and other load modifiers such as customer migration and TOU shifts that make it difficult to identify any specific COVID-19 patterns. Most likely, the application of calendar effects along with year specific binary explanatory variables in the regression equation already capture the load impacts of COVID-19. Therefore, finding further controls may not be necessary or feasible.

6. Apply Residential TOU Adjustment

Existing Residential customers, not already on a Time-of-Use (TOU) rate, will be moved to the Res TOU rate class starting in February 2022. Most customers will transition in May 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

- 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, Plug-In Electric Vehicle Charging Loads, 2022 Building Standards Update, and Building Electrification*

Growth in four known load/usage modifiers were separately modeled in this load forecast: 1) Net energy metered solar installations in residences, 2) Plug-in electric vehicle adoptions and the charging load impacts, 3) 2022 Building Standards Update, and 4) Building Electrification. Each is described in detail in sections below.

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 2019 – 2021 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 4 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	1.018205884	1.067141481	6.463%
2	1.017887535	1.066641052	6.414%
3	1.01744391	1.066023999	6.353%
4	1.017361881	1.065924552	6.344%
5	1.018109293	1.067167531	6.465%
6	1.020164877	1.071019494	6.841%
7	1.021155835	1.072921373	7.027%
8	1.021724374	1.074154118	7.147%
9	1.020330491	1.071243914	6.864%
10	1.018584897	1.06793265	6.540%
11	1.017872453	1.066604098	6.411%
12	1.018477313	1.067594042	6.508%
Average Annual	1.0189432285	1.0686973587	6.615%

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

Additional Mass Enrollments

No new mass enrollments are expected.

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 California Energy Commission (CEC) updated the building energy code in late 2021. This update sets new requirements for PV, water heating, space heating, and other electrification technologies. In addition to residential new construction, the update to the building energy code will also target new commercial buildings such as grocery stores, offices, retail stores, schools, and warehouses. The standard will go into effect in 2023. To account for this update to the building energy code, the North American Industrial Classification System (NAICS) code assigned to VCEA customers was used to identify customer segments impacted by this standard for the following (Non-NEM) rate classes: Small, Small TOU, Medium, and E19S. Since the customer count for the other commercial classes was kept constant, it was assumed that the updated building energy code would not impact these classes. The NAICS code was used to develop allocation factors which were then applied to the forecasted additions in customer count for these 4 rate classes. Considerably uncertainty exists in how to properly model the impact of this standard given its recent passage and so a compliance rate of 80% with the building energy code was assumed to be in effect over the forecast period. This assumption will be refined in the future as more data becomes available.

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 2021. 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.

Residential 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[3] identified a statewide target of needing 5 Million electric vehicles on the road in order to meet 2030 carbon emission reduction goals. VCEA contracted with a third-party consultant to develop an electrification forecast which included expected EV stock, estimated annual charging and a load shape. The EV stock was converted to annual additions and only new additions were added to the forecast using the assumption of 8,000 miles per EV with 0.56 kWh per mile. The EV stock forecast only went to 2030 so it was extended using the trend from 2025-2030 as the basis.

Table 5. VCEA Plug-in EV Stock

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Stock (#)	2,805	4,233	6,484	9,836	13,284	16,808	20,407	24,081	27,829	31,660	35,569	39,557	43,622	47,765
Additional Stock Annual	892	1,428	2,250	3,352	3,449	3,524	3,599	3,674	3,749	3,831	3,909	3,987	4,065	4,143
Additional Stock Cummulative	892	2,320	4,571	7,923	11,371	14,895	18,494	22,168	25,916	29,747	33,656	37,644	41,709	45,852
Additional MWh	3,997	10,395	20,477	35,493	50,944	66,730	82,853	99,311	116,105	133,268	150,781	168,644	186,856	205,419

To simplify modeling, we assumed all charging would be done in residences with the energy split between the Residential (non-TOU) and Residential TOU classes by the proportion of monthly customers counts in each rate class.

Building Electrification

There is an effort to shift energy usage from gas to electric to reduce carbon impacts. VCEA contracted with a third-party consultant to develop an electrification forecast which included expected stock of water heaters (WH) and space heaters (SH), and an hourly load shape by single-family dwellings (SFD), multi-family dwellings (MFD), small and mid-size enterprises (SME), and commercial and industrial (C&I) customers through 2030. Similar to the EV modeling above, only stock added after 2021 is added to the forecast because existing stock is included in the base forecast.

The electrification forecast was originally only through 2030. We extended the forecast past 2030 by calculating the energy per unit of stock for each category and trending the annual addition of stock using 2022-2030 as the basis. For the shape, we used similar years with 2023 as the shape for 2031 and 2024 as the shape for 2032, etc.

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[3] *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

The SFD and MFD were allocated to the Residential (non-TOU) and Residential TOU classes with the energy split by the proportion of monthly customers counts in each rate class (same as the EV charging). The SME electrification was split 40% to Small Commercial, 10% to Small TOU Commercial, and 50% to Medium Commercial based on energy sales. The C&I electrification was split 60% to E19S, 10% to E19P, 10% to E20S, and 20% to E20P based on energy sales.

Table 6. Building Electrification Impacts

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
SFD - WH														
Total Stock (#)	9,995	12,403	14,710	16,924	19,052	21,101	23,078	24,987	26,836	28,571	30,222	31,790	33,275	34,677
Additional Stock Annual	2,517	2,408	2,307	2,214	2,128	2,049	1,977	1,909	1,849	1,735	1,651	1,568	1,485	1,402
Additional Stock Cummulative	2,517	4,925	7,232	9,446	11,574	13,623	15,600	17,509	19,358	21,093	22,744	24,312	25,797	27,199
Additional MWh	3,128	6,121	8,988	11,739	14,384	16,931	19,387	21,761	24,058	26,214	28,266	30,216	32,061	33,803
SFD - SH														
Total Stock (#)	12,412	14,658	16,815	18,888	20,886	22,812	24,675	26,478	28,228	29,876	31,449	32,948	34,374	35,725
Additional Stock Annual	2,345	2,246	2,157	2,073	1,998	1,926	1,863	1,803	1,750	1,648	1,573	1,499	1,425	1,351
Additional Stock Cummulative	2,345	4,591	6,748	8,821	10,819	12,745	14,608	16,411	18,161	19,809	21,382	22,881	24,307	25,658
Additional MWh	4,378	8,572	12,600	16,471	20,201	23,798	27,275	30,642	33,909	36,986	39,924	42,724	45,385	47,908
MFD - WH														
Total Stock (#)	9,140	9,892	10,620	11,326	12,013	12,681	13,334	13,972	14,596	15,193	15,771	16,330	16,870	17,391
Additional Stock Annual	778	752	728	706	687	668	653	638	624	597	578	559	540	521
Additional Stock Cummulative	778	1,530	2,258	2,964	3,651	4,319	4,972	5,610	6,234	6,831	7,409	7,968	8,508	9,029
Additional MWh	149	294	433	569	701	829	955	1,077	1,197	1,312	1,422	1,530	1,633	1,733
MFD - SH														
Total Stock (#)	9,818	10,525	11,211	11,878	12,528	13,162	13,782	14,390	14,987	15,560	16,116	16,656	17,179	17,686
Additional Stock Annual	729	707	686	667	650	634	620	608	597	573	556	540	523	507
Additional Stock Cummulative	729	1,436	2,122	2,789	3,439	4,073	4,693	5,301	5,898	6,471	7,027	7,567	8,090	8,597
Additional MWh	140	276	407	535	660	782	901	1,018	1,132	1,242	1,349	1,453	1,553	1,651
SME - WH														
Total Stock (#)	4,022	4,455	4,860	5,240	5,596	5,930	6,243	6,537	6,812	7,057	7,278	7,477	7,652	7,803
Additional Stock Annual	463	433	405	380	356	334	313	294	275	245	222	198	175	152
Additional Stock Cummulative	463	896	1,301	1,681	2,037	2,371	2,684	2,978	3,253	3,498	3,719	3,918	4,093	4,244
Additional MWh	56	107	156	202	244	284	322	357	390	420	446	470	491	509
SME - SH														
Total Stock (#)	3,139	3,337	3,524	3,700	3,865	4,021	4,168	4,307	4,438	4,556	4,664	4,762	4,850	4,929
Additional Stock Annual	211	198	187	176	165	156	147	139	131	118	108	98	88	78
Additional Stock Cummulative	211	409	596	772	937	1,093	1,240	1,379	1,510	1,628	1,736	1,834	1,922	2,001
Additional MWh	2,665	5,167	7,529	9,751	11,836	13,807	15,664	17,418	19,073	20,565	21,930	23,169	24,283	25,271
C&I - WH														
Total Stock (#)	8,866	9,285	9,676	10,041	10,382	10,700	10,998	11,275	11,535	11,764	11,969	12,151	12,309	12,444
Additional Stock Annual	448	419	391	365	341	318	298	277	260	229	205	182	158	135
Additional Stock Cummulative	448	867	1,258	1,623	1,964	2,282	2,580	2,857	3,117	3,346	3,551	3,733	3,891	4,026
Additional MWh	231	447	649	837	1,013	1,177	1,330	1,473	1,607	1,725	1,831	1,925	2,007	2,076
C&I - SH														
Total Stock (#)	991	1,051	1,107	1,160	1,210	1,256	1,300	1,340	1,379	1,413	1,444	1,472	1,497	1,519
Additional Stock Annual	64	60	56	53	50	46	44	40	39	34	31	28	25	22
Additional Stock Cummulative	64	124	180	233	283	329	373	413	452	486	517	545	570	592
Additional MWh	861	1,668	2,423	3,135	3,806	4,426	5,016	5,558	6,080	6,543	6,961	7,337	7,670	7,960

Load Loss to Direct Access

Regarding CPUC Decisions 19-05-043 and 19-08-004, VCEA had a load loss starting in 2021. This is reflected in the actual data and customer counts, and no additional loss is expected.

Energy Efficiency and Demand-Side Management

In this IEPR 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 2022 IEPR forecast.

Climate Change and Electrification

Although not explicitly labeled as “climate change” in this VCEA 2022 IEPR forecast, the forecast incorporates a heat wave in July during the weekdays to create a peak simulation. In addition, the forecast uses 20 years of weather history, as opposed to a more traditional 30 years, capturing the more recently observed climate.

Apart from residential vehicle electrification and building electrification, additional possible future impacts of other electrification, were not modelled.