DOCKETED

Docket Number:	23-IEPR-02
Project Title:	Electricity Resource Plans
TN #:	250914-1
Document Title:	Valley Clean Energy Alliance 23-IEPR-02 Form 4
Description:	Form 4 is included in the attachment for Valley Clean Energy Alliance's 2023 IEPR submittal.
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Organization:	The Energy Authority
Submitter Role:	Applicant Consultant
Submission Date:	7/3/2023 9:58:47 AM
Docketed Date:	7/3/2023

Valley Clean Energy Alliance

2023 Integrated Energy Policy Report

Electricity Demand Forecast Filling

Form 4 – Demand Forecast Methodology

Submitted

July 3rd, 2023

Forecast Process

The method used for the 2023 VCEA IEPR Electricity Demand Forecast submittal is described in the steps listed below.

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 2019-2022 was analyzed. For each rate class, the class 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.

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

Figure 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)

2. Developing the Normalized Weather Forecast

Historical weather data for 2013-2022 was obtained from DTN Weather. The weather station used for VCEA's service territory was the Nut Tree Airport in Vacaville, CA. The weather variables used in this forecast included hourly temperature, daily lagged temperature, precipitation, dew point, relative humidity, and sunshine minutes.

To develop the normal hourly weather pattern, daily average historical temperatures were ranked within each month in the historical dataset. For each month, the median temperature day for each rank was then calculated. These median-ranks were then rearranged based on 2022 historical weather pattern. For each of the median-ranks, the actual historical weather data for that day was obtained and used as the hourly weather pattern for the particular day in the year.

This produced an hourly weather normal forecast that incorporated peak weather events based on the median hottest and coldest day for each month in the historical time period.

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

Economic projections for the VCEA service territory were used to project customer count growth through the forecast period. The actual and forecasted economic data was obtained from Woods & Poole's 2022 Complete Economic and Demographic Data Source. This data source includes county level historical data beginning in 1970 and projections extending through 2060 for many different economic indicators. Projections for Yolo County were used to project VCEA customer counts using a linear regression model.

The figure below shows the projected number of households and total employment for Yolo County, which was assumed to reflect similar trends in the VCEA service territory.

Figure 2. Economic Growth Rates for VCEA Service Area (Woods & Poole)

Year	Number of Households		Total Employment	
	Value (thousands)	YoY Change (%)	Value (thousands)	YoY Change (%)
2023	79.9	1.4%	152.5	2.1%
2024	80.9	1.3%	154.5	1.3%
2025	82.0	1.3%	156.6	1.3%
2026	82.9	1.2%	158.6	1.3%
2027	83.9	1.1%	160.6	1.3%
2028	84.8	1.1%	162.6	1.2%
2029	85.6	1.0%	164.5	1.2%
2030	86.5	1.0%	166.5	1.2%
2031	87.3	0.9%	168.5	1.2%
2032	88.0	0.9%	170.4	1.2%
2033	88.8	0.9%	172.4	1.1%
2034	89.5	0.8%	174.3	1.1%

The starting point for the customer count forecast was based on the number of VCEA customers from monthly EIA reports as of December 31st, 2022. The growth rates above were applied to the December 2022 customer counts to produce the customer count forecast from 2023 to 2034.

The annual growth rate for number of households was used to forecast the number of customers for the residential rate classes. The total employment growth rate was used to forecast the number of customers for the small and medium commercial classes.

The customer counts in the E19S, E19P, E20S, E20P, street lights, traffic signal, and agriculture rate classes were kept constant at their 2022 levels due to lack of information and uncertainty regarding their growth over the forecast period.

Annual growth rates were applied monthly to produce a gradual increase in customer counts over each year in the forecast horizon.

4. Develop Rate Class-Specific Load Forecasts

The historical hourly retail load, weather data, and customer counts were used to train a machine learning model for each rate class. In addition to this, time series descriptive variables such as month, weekday, day of the month, hour ending, and a holiday indicator were utilized in the model training. The model utilized the gradient boosted trees algorithm[1], which aims to predict a variable by combining estimates from a set of simpler models. In this case, the simpler models were linear regression models.

For Street Lighting and Traffic Control customer classes, the only time series descriptive variables considered were month and hour ending, since these load classes are not impacted by weekday, holidays, or the day of the month.

The E19P customer class saw a fundamental shift in its load profile during September 2020 which was not driven by a change in customer counts. An indicator variable was included during model training for this customer class beginning September 2020. The result of this indicator variable inclusion in the model is a favoring of load history after September 2020 in the E19P load forecast. Similarly, the E19S customer class observed a fundamental shift in its load profile beginning April 2021. An indicator variable was also included during model training for this customer class beginning April 2021 to favor more recent history during model training.

Existing Residential customers not already on a Time-of-Use (TOU) rate were moved to the Res TOU rate class in 2022. Most customers transitioned in May while NEM customers transitioned as their True-Up bills occur over the course of the year. Low-income (CARE) customers did not need to transition and may remain in the non-TOU Residential rate class. This large shift in customer counts from non-TOU to TOU was reflected in the customer count history. In addition to this, an indicator variable was

[1] The xgboost package for the R programming language was used to create the gradient boosting model. For additional information, see https://www.rdocumentation.org/packages/xgboost/versions/1.7.5.1

included during model training beginning May 2022 for Residential customer classes to better consider this shift.

The hourly normalized weather forecast, customer count forecast, time series descriptive variables, and any adjustments mentioned above were then used to predict hourly load using the trained model for each rate class.

5. Additional Adjustments or Considerations

Additional considerations and adjustments for the base load forecast are described in detail in sections below.

1. Additional Mass Enrollments

No new mass enrollments are expected.

2. 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).

3. Net Energy Metered Distributed Generation Adoption

While not explicitly added as an adjustment to the base load forecast, net energy metered (NEM) solar installations are implicitly included in the historical retail meter interval data used for model training.

4. Residential Plug-In Electric Vehicle Charging Loads

Adoption of electric vehicles (EVs) is expect to have a significant impact on load due to vehicle charging. 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.

Figure 3. VCEA Plug-in EV Stock

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total Stock (#)	5,018	7,686	11,659	15,747	19,924	24,190	28,545	32,989	37,530	42,164	46,890	51,709
Additional Stock Annual	2,213	2,667	3,973	4,088	4,177	4,266	4,355	4,444	4,541	4,634	4,726	4,819
Additional Stock Cummulative	2,213	4,880	8,854	12,942	17,119	21,385	25,740	30,183	34,725	39,358	44,085	48,904
Additional MWh	9,914	21,864	39,665	57,980	76,693	95,805	115,314	135,222	155,566	176,326	197,500	219,089

To simplify modeling, we assumed all charging would be done at residential customer's homes. Additional charging MWh shown above were added to the residential load.

5. 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 2022 is added to the forecast because existing stock is included in the base forecast.

The electrification forecast was originally only through 2030. The forecast was extrapolated past 2030 by calculating the energy per unit of stock for each category and trending the annual addition of stock using 2023-2030 as the basis.

The SFD and MFD were allocated to the Residential classes, while the SME electrification was allocated to Commercial customer classes. The C&I electrification was split between commercial and industrial classes based on a load ratio share, with approximately 90% of the electrification allocated to commercial and 10% allocated to industrial classes.

Figure 4. Building Electrification Impacts

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
SFD - WH												
Total Stock (#)	12,403	14,710	16,924	19,052	21,101	23,078	24,987	26,836	28,571	30,222	31,790	33,275
Additional Stock Annual	2,408	2,307	2,214	2,128	2,049	1,977	1,909	1,849	1,735	1,651	1,568	1,485
Additional Stock Cummulative	2,408	4,715	6,929	9,057	11,106	13,083	14,992	16,841	18,576	20,227	21,795	23,280
Additional MWh	2,993	5,891	8,611	11,256	13,803	16,327	18,633	20,930	23,106	25,160	27,111	28,958
SFD - SH												
Total Stock (#)	14,658	16,815	18,888	20,886	22,812	24,675	26,478	28,228	29,876	31,449	32,948	34,374
Additional Stock Annual	2,246	2,157	2,073	1,998	1,926	1,863	1,803	1,750	1,648	1,573	1,499	1,425
Additional Stock Cummulative	2,246	4,403	6,476	8,474	10,400	12,263	14,066	15,816	17,464	19,037	20,536	21,962
Additional MWh	4,194	8,328	12,093	15,823	19,420	23,127	26,264	29,531	32,677	35,621	38,425	41,092
MFD - WH												
Total Stock (#)	9,892	10,620	11,326	12,013	12,681	13,334	13,972	14,596	15,193	15,771	16,330	16,870
Additional Stock Annual	752	728	706	687	668	653	638	624	597	578	559	540
Additional Stock Cummulative	752	1,480	2,186	2,873	3,541	4,194	4,832	5,456	6,053	6,631	7,190	7,730
Additional MWh	145	286	420	552	680	808	928	1,048	1,163	1,274	1,382	1,486
MFD - SH												
Total Stock (#)	10,525	11,211	11,878	12,528	13,162	13,782	14,390	14,987	15,560	16,116	16,656	17,179
Additional Stock Annual	707	686	667	650	634	620	608	597	573	556	540	523
Additional Stock Cummulative	707	1,393	2,060	2,710	3,344	3,964	4,572	5,169	5,742	6,298	6,838	7,361
Additional MWh	136	271	395	520	642	770	878	992	1,105	1,212	1,316	1,417
SME - WH												
Total Stock (#)	4,455	4,860	5,240	5,596	5,930	6,243	6,537	6,812	7,057	7,278	7,477	7,652
Additional Stock Annual	433	405	380	356	334	313	294	275	245	222	198	175
Additional Stock Cummulative	433	838	1,218	1,574	1,908	2,221	2,515	2,790	3,035	3,256	3,455	3,630
Additional MWh	51	100	146	188	228	267	301	334	364	390	414	435
SME - SH												
Total Stock (#)	3,337	3,524	3,700	3,865	4,021	4,168	4,307	4,438	4,556	4,664	4,762	4,850
Additional Stock Annual	198	187	176	165	156	147	139	131	118	108	98	88
Additional Stock Cummulative	198	385	561	726	882	1,029	1,168	1,299	1,417	1,525	1,623	1,711
Additional MWh	2,502	4,912	7,086	9,171	11,142	13,100	14,753	16,408	17,929	19,296	20,538	21,653
C&I - WH												
Total Stock (#)	9,285	9,676	10,041	10,382	10,700	10,998	11,275	11,535	11,764	11,969	12,151	12,309
Additional Stock Annual	419	391	365	341	318	298	277	260	229	205	182	158
Additional Stock Cummulative	419	810	1,175	1,516	1,834	2,132	2,409	2,669	2,898	3,103	3,285	3,443
Additional MWh	216	419	606	782	946	1,103	1,242	1,376	1,495	1,601	1,695	1,777
C&I - SH												
Total Stock (#)	1,051	1,107	1,160	1,210	1,256	1,300	1,340	1,379	1,413	1,444	1,472	1,497
Additional Stock Annual	60	56	53	50	46	44	40	39	34	31	28	25
Additional Stock Cummulative	60	116	169	219	265	309	349	388	422	453	481	506
Additional MWh	807	1,570	2,274	2,945	3,565	4,172	4,697	5,219	5,686	6,105	6,482	6,815

6. 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.

7. Energy Efficiency

For VCEA customers, there are a number of energy efficiency programs that are available through PG&E. This includes items such as rebates on smart thermostats. Because of this, publicly available hourly energy efficiency impacts from PG&E's 2022 IEPR forecast[2] were used as the basis for VCEA's energy efficiency forecast. For simplicity, these hourly energy efficiency impacts were scaled down based on the ratio of VCEA and PG&E projected total annual energy. The scaled hourly energy efficiency impact was then split between Residential, Commercial, and Industrial rate classes based on their load ratio share.

8. Climate Change

While no explicit impacts due to climate change were included in the forecast, the weather normalization process does incorporate peak weather events during the summer and winter months. In addition to this, the forecast uses 10 years of weather history, as opposed to a more traditional 30 years, meaning the weather normal forecast reflected more recent weather trends.

6. 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.

Hourly retail and wholesale load data for 2019-2022 was collected and the percent different between the two load volumes was calculated to determine the hourly distribution loss factor. These hourly loss factors were averaged by month to create monthly factors for the entire system. The factors are shown in Figure 5 below.

[2] The base energy efficiency forecast was utilized from PG&E's 2022 IEPR forecast. For additional information, see https://efiling.energy.ca.gov/GetDocument.aspx?tn=248357

Figure 5. PG&E Distribution Loss Factors

Month	Weighted Distribution Line Loss
Jan	6.29%
Feb	6.31%
Mar	6.09%
Apr	6.08%
May	6.34%
Jun	6.79%
Jul	6.97%
Aug	7.07%
Sep	6.72%
Oct	6.26%
Nov	6.16%
Dec	6.33%
Annual Average	6.45%

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

Forecast Review

Overall, the VCEA 2023 IEPR forecast is projecting an average of 2.5% total retail load growth year-over-year from 2023-2034. While this is lower than the average historical total load growth observed from 2019-2022, 5.0% year-over-year, a substantial growth in customer counts was observed during 2020 which drove up the average historical load growth. In 2023, projected total load decreases from 2022 levels. This drop in 2023 load is a result of the weather normalization process, which is projecting cooler summer weather when compared to the 2022 weather history, resulting in lower load volumes. From 2024 onward, total load is projected to increase year-over-year.

Projected wholesale peak load growth is averaging 0.3% year-over-year from 2023-2034. This is substantially below the 2019-2022 historical growth, which averaged 8.7% year-over-year. Similar to total load, a contributor to this separation between the history and forecast is substantial customer count growth that was observed in 2020, which resulted in a 13.2% increase in peak load from 2019 levels. In addition to this, a heavy contributor to the low forecasted peak load growth is an 8.7% decrease in projected peak load in 2023 from 2022 levels. This drop in load is again due to the weather normalization process, which is projecting less extreme weather during summer 2023 when compared to 2022 history.

The annual growth in total load is expected to outpace annual growth in peak load. This is heavily impacted by projected electric vehicle charging, which is assumed to primarily occur during nighttime hours. This results in vehicle charging having a lesser impact on peak load growth when compared to total load.

The historical and projected wholesale peak load and retail total load is shown below in Figure 6.

Figure 6. Annual Load Forecast