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Form 4. Demand Forecast Methods and Models

The City of Anaheim (City) is the second largest city in Orange County and tenth largest city in California. It is best known as the home to the Disneyland® Resort and the Anaheim Convention Center.

Anaheim Public Utilities (APU) is a city-owned, not-for-profit electric and water utility that delivers electricity to Anaheim's 350,000 residents and more than 15,000 businesses, including multi-million dollar tourism, sports, and manufacturing customers. Although residential customers make up 85% of APU's total customers, nearly 75% of total electrical load is consumed by commercial and industrial customers. APU experiences seasonal trends in which the summer months experience higher loads due to cooling needs, while the rest of the year tends to remain fairly stable.

In determining APU's energy demand forecast, staff considered historical energy demand and customer growth trends as the basis for statistical modeling and econometric forecasting techniques to develop a "**base energy demand forecast.**" Once developed, the base forecast was further adjusted (referred to as the **adjusted energy demand forecast**) by planned system expansion, expected EV energy demand, estimated customer-side solar PV installation, and the effect of demand side management and energy efficiency. While system expansion and EV growth increase the energy demand, solar installation and energy efficiency programs reduce the energy demand.

The **adjusted energy demand forecast** was then used as the basis for the development of the total energy to serve load, retail electricity by customer class, peak demand, and hourly energy demand forecasts provided in IEPR demand forms 1.1b, 1.2, 1.3, 1.5, and 1.6.

ECONOMETRIC MODELING FOR BASE ENERGY DEMAND FORECAST

Econometric modeling is the application of mathematical and statistical methods to forecast future values the help understand the relationship between variables. APU develops its forecast of total system energy consumption using econometric modeling. Hourly energy demand is estimated using least squares estimation and variables for expected temperature, calendar (weekday versus holiday), season and time effects (which capture specific hours, as well as the cumulative impact of prolonged heat waves). Five years of historical hourly data are used to estimate the following econometric equation:

$$\textit{Total Energy}_t = \alpha + \beta_1\, \textit{Temperature}_t + D_1\, \textit{Holiday}_t + V_t + M_t + \varepsilon_t$$

Where:
Temperature_t = Temperature at hour t
Holiday_t = Dummy variable to identify weekend and NERC holidays
V_t = Vector of dummy variables for the hours
M_t = Vector of dummy variables for the months
ε_t = Error term

VARIABLES INCLUDED: TEMPERATURE FORECAST AND WEATHER ASSUMPTIONS

APU owns calibrated equipment at the Linda-Vista Reservoir that records hourly temperature in the Supervisory Control and Data Acquisition (SCADA) system. The total energy demand forecast assumes normal weather conditions and uses average hourly temperatures from the past five years (2014 – 2018). It is important to analyze the impact of weather extremes on energy demand due to its sensitivity related to temperature changes. Extreme temperature forecasts under high and low emission scenarios are available through Cal-Adapt, a climate change resource database developed by the Geospatial Innovation Facility at the University of California, Berkeley with funding and advisory oversight by the California Energy Commission.

The extreme temperature forecast data for the Anaheim area was obtained through Cal-Adapt[1] and then compared to APU's internal temperature forecast, which was developed using five-year minimum and maximum temperatures. APU's forecast consistently produces higher extremes than the Cal-Adapt forecast. As the APU forecast produces higher extremes, it was selected to be the preferred temperature forecast to conduct extreme weather analysis on energy demand and corresponding standard deviations weather used to calculate the One-in-K Peak Demand Weather Scenario Forecast reported in Form 1.5. The extreme weather analysis is conducted by using high and low temperatures in the model to estimate total and peak demand.

VARIABLES EXCLUDED: ECONOMIC AND DEMOGRAPHIC FORECAST

Anaheim is a fully developed Orange County city with historically consistent growth, median income level, and employment rate. A series of modeling tests determined that the inclusion of economic and demographic variables leads to increased variability, and results in overly optimistic demand growth. The hourly demand estimation excluding these variables proved to be more accurate. Although economic and demographic variables are excluded from the base model, planned expansions and energy reductions are included as adjustments after the econometric regression modeling is complete.

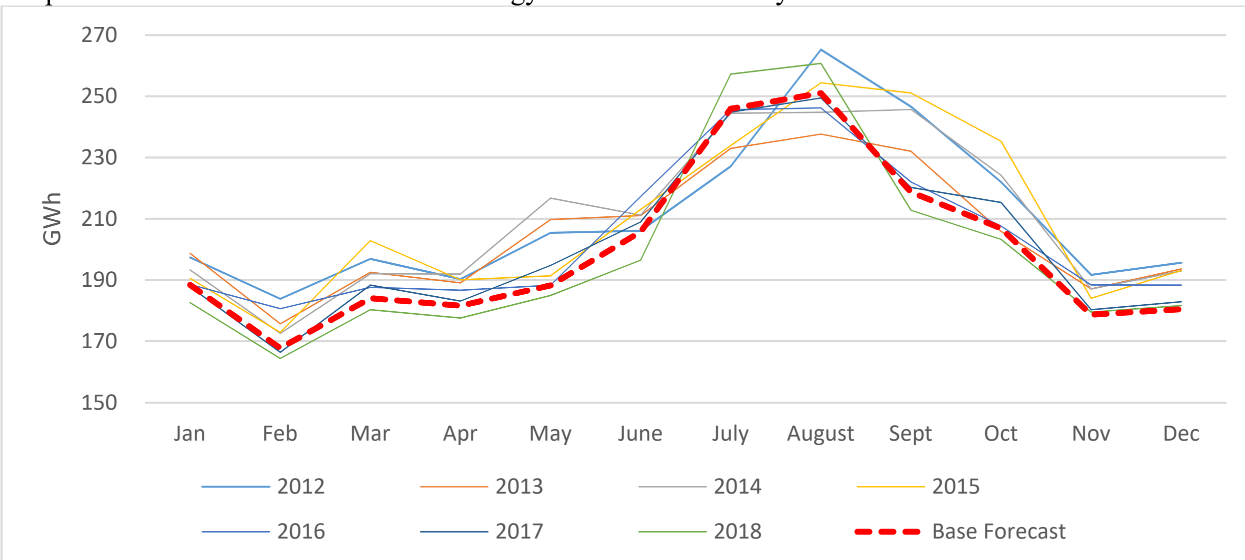
MODEL CALIBRATION

The base econometric model is validated by comparing modeling results to historical energy demand data. Essentially, the model is used to develop energy demand forecasts for historical years 2012 through 2018, with more weight attributed to 2017 and 2018 due to changing load patterns. The forecast results are compared to historical actual values and analyzed for reasonableness. As seen in Graph 1 below, the Base Energy Demand Forecast is comparable to historical energy demand. Overall, annual energy demand shape remains fairly constant, overall consumption appears to be lower than that of recent years, which is a reflection of energy efficiency and distributed generation impacts.

Further calibration is done by estimating historical demand using the Base Energy Demand Model and historical variable data. The model was proven to produce efficient estimation results of historical demand in the range of 0.1% to 4% variance for the testing period. Had the model been proven inefficient, alternative variables would have been introduced and a new model established to go through the validation process again.

[1] http://cal-adapt.org/

Graph 1. Historical Demand and Base Energy Demand Forecast by Month



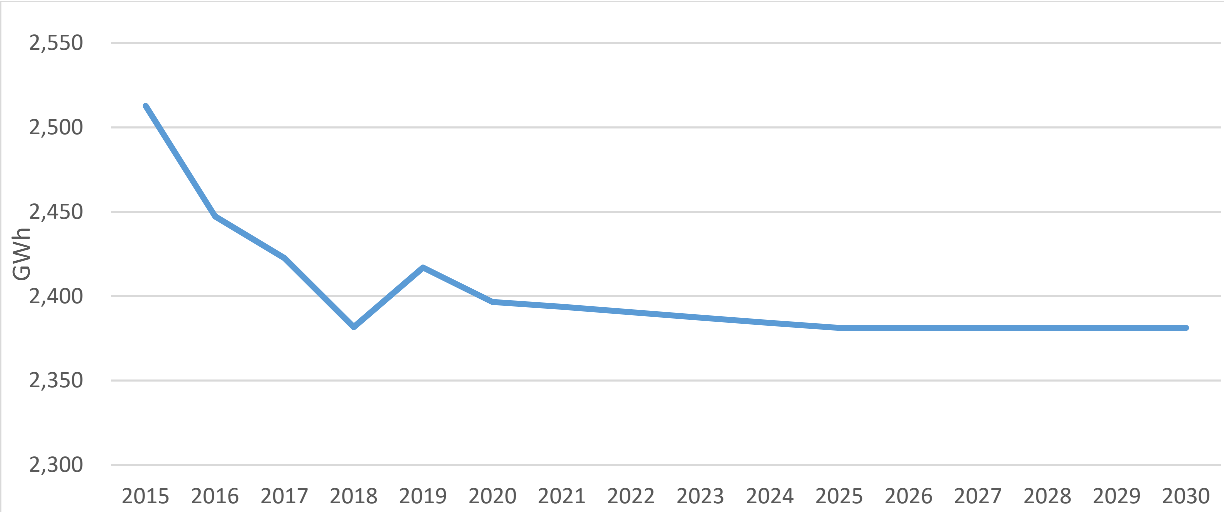
ADUSTMENTS MADE TO BASE ENERGY DEMAND FORECAST: FORM 1.2

The second step to develop the Total Energy Demand Forecast in Form 1.2 is to **adjust the Base Energy Demand Forecast** by taking into consideration residential and commercial projects within the City that may affect energy demand. Most of the open land in Anaheim is fully developed. While new building developments may contribute to energy demand increase, a corresponding decrease also occurs from the demolition of existing buildings and infrastructure. As such, it is not appropriate to apply a growth rate based on historical trends. Rather, new development data is gathered from City permits and from Electric System Planning, and these net impacts to energy demand are applied to the base model.

Information related to these projects is collected through collaboration with the City's Planning Department, APU Electric System Planning, and Business & Community Programs. Project timelines are evaluated and incorporated into adjustments that either increase or decrease the "base" forecast. Anaheim's most recent development projects which include City-wide development, expansion plans and electric vehicle growth are expected to cumulatively contribute an additional 42 GWh of load growth through 2030. Simultaneously, projects expected to decrease load such as energy efficiency, commercial-scale and residential solar photovoltaic (PV), fuel cells and other behind-the-meter distributed generation resources are expected to cumulatively contribute an additional 62 GWh of load reductions through 2030.

The anticipated growth and reductions are applied to the Base Energy Demand Forecast to create the Adjusted Energy Demand Forecast, which is reported in IEPR Form 1.2 under the column titled "Total Energy to Serve Load". Because load reduction expectations are larger than anticipated growth, the Adjusted Energy Demand Forecast displays slowly declining energy demand through 2030. This trend can be seen in Graph 2 below.

Graph 2. Historical Demand and Adjusted Energy Demand Forecast by Calendar Year



RETAIL ELECTRICITY SALES BY CUSTOMER CLASS: FORM 1.1B

The Retail Sales of Electricity by Customer Class is developed from the Adjusted Energy Demand Forecast. Historical distribution system losses are calculated by determining the delta between energy delivered at APU's Lewis substation and retail sales billed. The historical system loss has been in the range of 3.3% to 3.8%. This system loss factor is applied to the Adjusted Energy Demand Forecast to develop the Total Retail Electricity Sales Forecast.

To develop electricity sales by customer class, the Total Retail Electricity Sales Forecast is split into six customer categories: Residential, Commercial, Industrial, Agriculture, Water Pumping, and Street Lighting. The proportion allocated to each customer class is determined by the average of the four-year historical proportion percentages. The forecasted percentages applied to the Adjusted Energy Demand Forecast are located below in Table 2.

Table 2: Forecasted Customer Class Proportion Percentage

RESIDENTIAL	COMMERCIAL	INDUSTRIAL	AGRICULTURAL	WATER PUMPING	STREET- LIGHTING
25.8%	*32.5%*	*40.8%*	*0.5%*	*0.4%*	*0.03%*

HISTORICAL FORECAST ACCURACY (BY FISCAL YEAR)

The APU Adjusted Energy Demand and Retail Electricity Sales by Customer Class are further evaluated by comparing accuracy of forecast to actual on a fiscal year basis. Over the last six years have been within 2.34% accuracy (on average). On average, the forecast accuracy has been within 1.9% of Total Energy Demand and 1.27% of Retail Electricity sales. Detailed information is located in Table 3 below.

Table 3: Energy and Retail Energy Demand Forecast Accuracy

FY Ending	Forecast System	Actual System	Difference	Forecast Retail	Actual Retail	Difference	Type of Forecast
2018	2,436	2,380	2.29%	2,347	2,313	1.46%	Econometric
2017	2,502	2,427	2.98%	2,411	2,343	2.79%	Econometric
2016	2,464	2,501	-1.50%	2,378	2,401	-0.97%	Econometric
2015	2,447	2,500	-2.17%	2,362	2,398	-1.52%	Historical Data
2014	2,446	2,465	-0.78%	2,375	2,376	-0.04%	Historical Data
2013	2,484	2,525	-1.65%	2,397	2,417	-0.83%	Historical Data
Average			**1.9%**			**1.27%**	

PEAK DEMAND FORECAST: FORM 1.3

APU uses load factor methodology to develop the Peak Demand Forecast. Historical monthly load factors are calculated by dividing the monthly total energy demand by the month's respective peak demand. The five-year historical average load factors are then applied to the Adjusted Energy Demand Forecast for each month to develop the 1-in-2 Temperature Peak Demand Forecast using the formula:

$$\frac{\text{Total Monthly Energy Demand / \# of hours in month}}{\text{Load factor}}$$

Historical load factors are displayed in Table 4. The Peak Demand Forecast is calibrated using the same methods for the Base Energy Demand Forecast, by observing for reasonableness and applying the methodology to estimate previous five year's actual data. The Peak Forecast accuracy to predict monthly peak is between 0.3% and 3%. The annual peak forecast accuracy was in the range of -1% to 5% and within the acceptable confidence level.

Table 4: Historical Load Factor

	CY2014	CY2015	CY2016	CY2017	CY2018	AVERAGE
Jan	80%	73%	79%	78%	78%	78%
Feb	80%	77%	72%	69%	78%	75%
Mar	75%	76%	68%	75%	74%	74%
Apr	77%	66%	62%	68%	71%	69%
May	58%	55%	61%	75%	68%	63%
June	64%	74%	66%	54%	63%	64%
July	67%	66%	69%	62%	68%	66%
August	60%	65%	65%	63%	60%	62%
Sept	59%	59%	60%	58%	54%	58%

Oct	72%	62%	59%	50%	53%	59%
Nov	70%	66%	79%	62%	67%	69%
Dec	77%	88%	78%	79%	76%	79%
Total	70%	69%	68%	66%	67%	68%

HISTORICAL FORECAST ACCURACY

The APU Peak Load Forecast is further evaluated by comparing accuracy of forecast to actual on an annual basis. Over the last six years, the forecast has been within 2% accuracy (on average). The load factor methodology has been implemented since 2016 and proves to be a much more accurate method to forecast peak load, compared to historical data and economic methods used prior to 2016. Detailed information is located in Table 5 below.

Table 5: Historical Peak Forecast Accuracy

	Forecast Peak	Actual Peak	% Difference	Forecast Type
2013	555	549	1.08%	Historical Data
2014	549	578	-5.28%	Historical Data
2015	560	584	-4.29%	Historical Data
2016	562	561	0.18%	Load Factor
2017	553	562	-1.63%	Load Factor
2018	538	554	-2.97%	Load Factor
AVERAGE	553	565	-2%	

PEAK DEMAND WEATHER SCENARIOS FORECAST: FORM 1.5

As detailed above under the section "Variables Include: Temperature Forecast and Weather Assumptions", extreme weather forecasts and their standard deviations are calculated for total demand and peak demand using APU internal extreme temperature assumptions. These forecasts are assumed to be normally distributed and therefore the peak weather impacts can be estimated using the following statistical formulas:

1-IN-5 PEAK: PEAK FORECAST + 0.842 X STANDARD DEVIATION (PEAK FORECAST)

1-IN-10 PEAK: PEAK FORECAST + 1.282 X STANDARD DEVIATION (PEAK FORECAST)

1-IN-20 PEAK: PEAK FORECAST + 1.645 X STANDARD DEVIATION (PEAK FORECAST)

RENEWABLE AND DISTRIBUTED GENERATION: FORM 1.7

Historical behind-the-meter distributed generation information is obtained from SB 1, City permit and interconnection applications and reported on the 1304(b) report. This includes micro turbine, fuel cell, and photovoltaic (PV) installations. Short-term PV installation growth is estimated using system size data listed on the resident's permit application. Long-term PV installation growth is estimated using a linear trend of historical installation totals. APU estimates to have 34 MW of installed PV capacity in 2019, and 75 MW by 2030. This forecast is detailed under the table "Installed Capacity (MW)" on Form 1.7a.

To estimate PV generation, APU collects hourly solar generation data from the power production meter installed at the Anaheim Convention Center located at 800 W. Katella Ave. Anaheim, California. The hourly solar generation data is used to develop a 'proxy capacity factor' by calculating generation divided by capacity. The annual average proxy capacity factor is applied to the installed PV capacity forecast to develop the total PV generation forecast. For example, the historical annual average proxy capacity factor is 18%. This capacity factor can estimate the total PV generation for 2018 using the following formula: 0.18 x 30MW installed capacity x 8760 hours in a year = 48GWh. The historical estimated PV generation and PV generation forecast is reported under the table "Energy (GWh)" on Form 1.7a.

The Coincident Peak Demand Impact is estimated by applying the calculated capacity factor of the Anaheim Convention Center PV system at the time of APU peak load to the total installed solar capacity. For example, the APU peak in 2018 was 554 and occurred on July 6 on hour ending 16. The total convention center generation on that day and hour was 1,100 KWh, which equates to a 52% capacity factor. This proxy capacity factor is then applied to the installed PV capacity of 30MW to determine an estimated peak impact of nearly 16MW. Estimated historical peak impact and peak impact forecasts are detailed in the table "Coincident Peak Demand Impact (MW)" on Form 1.7a.

APU is not aware of any customer installed battery storage; however, it does have Thermal Energy Storage. Historical data for these units is collected from City permits or program rebate applications and reported on the California Energy Commission's 1304(b) report. Because these units are stable generation units, generation is estimated using total installed capacity and a 95% capacity factor. Thermal Energy Storage systems are peak shifters, and therefore the impact on coincident peak is estimated using the same methodology, the impact to peak is the amount of generation the unit is capable of, 95% of the unit's capacity. APU does not develop a forecast for energy storage at this time, however the historical data is detailed on Form 1.7a, 1.7b and 1.7c.

For more information on PV and Distributed Generation impacts, refer to Form 6.

ADDITIONAL FORECAST DETAIL: ENERGY EFFICIENCY

Energy efficiency is a factor that is applied to the Base Demand Energy Forecast to develop the Adjusted Demand Energy Forecast. In accordance with AB 2021, APU is required to establish specific annual energy saving goals as a percentage of total annual retail electric consumption. Senate Bill 350 also mandated that the CEC develop utility-specific energy efficiency saving targets to help achieve doubling statewide energy efficiency savings in electricity and natural gas end uses by 2030.

APU, in conjunction with other members within the California Municipal Utilities Association, contracted with Navigant Consulting, Inc. (Navigant) to identify all potentially achievable cost-effective electricity efficiency savings and establish annual targets for energy efficiency savings for 2018-2027. The final report "Energy Efficiency in California's Public Power Sector' was published and submitted to the CEC in 2017. Anaheim City Council adopted APU's ten-year energy saving goal in March 2017, based on study results from the Navigant report.

For more information on energy efficiency impacts, refer to Form 6.

ADDITIONAL FORECAST DETAIL: DEMAND-SIDE MANAGEMENT

APU operates two demand-side management programs, including the Voluntary Load Reduction Program which is designed for large commercial, industrial, institutional, and municipal customers, and the myPower Savings Program, which is designed for residential customers.

Voluntary Load Reduction Program

The Voluntary Load Reduction Program is designed for large customers who can curtail a minimum of 200 kW of their load within 30 minutes of being notified by APU. These eligible customers are capable of assisting APU comply with a California Independent System Operator (CAISO) order to curtail system load during a Stage 3 Alert and/or a transmission system emergency.

A CAISO Stage 3 Alert is called when statewide operating reserves for electric generation fall below 3%, which increases the likelihood of system and regional electric system outages. In order to prevent widespread outages, the CAISO will take certain actions to ensure the stability and reliability of the State's electric power Grid. During a Stage 3 Alert, the CAISO may institute mandatory load curtailment throughout the State for typically one to four hours to maintain system reliability when electricity usage is at its peak. APU may be ordered to participate in load curtailment if sustained high electric loads threaten blackouts throughout the State.

This voluntary program does not offer financial incentives to participants and does not include any financial penalties for not curtailing load when requested or not sustaining load curtailment during the duration of the CAISO Stage 3 Alert. Participating customers receive the benefit of eliminating the risk of unplanned total electric service outages that result from CAISO orders to curtail firm load during a Stage 3 Alert, in exchange for voluntary load reduction during the entire duration of a CAISO Stage 3 Alert.

The economic benefits to participating customers are a function of the savings realized from a coordinated interruption of individual business processes and the expected risk of a CAISO ordered load curtailment event. For those customers that maintain continued participation in this program, APU bypasses, where feasible, that customer's circuit from mandatory rotating outages during an order by the CAISO to curtail load. Currently APU has 10,688 kW of load in the Voluntary Load Reduction Program that includes business customers, City properties, and water pump stations.

APU's load forecast is based on normalized weather conditions and does not expect any CAISO Stage 3 Alert or a transmission system emergency. Therefore, the energy saving forecast is zero and the program does not have an impact on demand forecast calculations. The forecast listed in Form 3.4 is the total eligible MW of the program participates whom may voluntarily reduce load upon a CAISO Stage 3 Alert or a transmission system emergency.

myPower Savings Program

In 2017 and 2018, APU implemented a pilot residential demand response program named myPower Savings Program. It is based on behavioral demand response, and APU has called events and sent signals to enrolled customers based on criteria such as high wholesale energy prices, CAISO Alert or Warning notices, system emergencies, and extreme or unexpected weather conditions. Events are limited to non-holiday weekdays, and the total number of events is capped during the program duration.

Eligible customers receives a one-time bill credit for enrolling in the program. When a program event is called, APU notifies enrolled customers of the upcoming event by email or text message based on customers' preferences. Enrolled customers have the freedom to reduce energy consumption however they wish during the event hours, and they can also earn bill credits based on the kilowatt-hour (kWh) they reduce.

The pilot residential demand response program generated 794 kWh savings in summer 2017 and 738kWh savings in summer 2018. The forecast listed in Form 3.4 is the based upon historical savings.

For more information on demand response impacts, refer to Form 6.