DOCKETED

Docket Number:	17-IEPR-03
Project Title:	Electricity and Natural Gas Demand Forecast
TN #:	217073
Document Title:	2017 Anaheim IEPR Form 4
Description:	2017 Anaheim IEPR Form 4
Filer:	Mei Pan
Organization:	City of Anaheim
Submitter Role:	Public Agency
Submission Date:	4/17/2017 10:41:46 AM
Docketed Date:	4/17/2017

City of Anaheim
April 2017
CEC IEPR 2017

Form 4. Demand Forecast Methods and Models

I. Forecast Overview

The City of Anaheim, Public Utilities Department (APU) develops forecasts for the following:

- Hourly System Loads
- Total Monthly System Load
- Monthly System Peak
- Monthly Retail Load for Residential, Commercial, Industrial and Other customer classes

APU uses econometric modeling to forecast total system load. The peak load forecast is derived from the total system load forecast using a five-year average load factor. Monthly retail load for each customer class is estimated using historical distribution percentages. The City uses STATA (SE 13) as its econometric software and calibrates each forecast to historical data, evaluating the efficiency of each model annually. Adjustments are made to the model as needed.

I(a). Total System Load Forecast Methodology

Hourly total system load is forecasted using five years of historical hourly data to estimate the following econometric regression equation:

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

Where:
Temperature = Temperature at hour t
Holiday = Dummy variable to identify weekend and holidays
V_t = Vector of dummy variables for hours 2-24
M_t = Vector of dummy variables for month 2-12
ε_t = Error term

Simulation results are located in the Appendix. Following the econometric estimation, the hourly forecasted load is summed up to develop the monthly and annual total system load forecast.

Weather Assumptions

Hourly temperature observations are obtained from equipment owned and maintained by the City of Anaheim (City) at its Linda-Vista Reservoir. This data is included within its SCADA system.

Temperature forecasts were not developed using an econometric analysis, but instead APU prefers to assume normal weather in forecasting, using the past five-year average hourly temperatures.

Econometric Model Calibration

The econometric model is validated by calibrating the model to previous year's actual consumption data. APU performed forecast accuracy tests to actual data for 2013 through 2016. The model produced efficient estimation results in the range of 0.4% to 2.1% for the testing period.

Historical and Forecasted Load

Graph 1 displays a representation of the forecast results. Table 1 details the difference percentage of the monthly system load forecast, as compared to the actual consumption data for 2013 through 2017.

Graph 1. System Load Economic Model Results

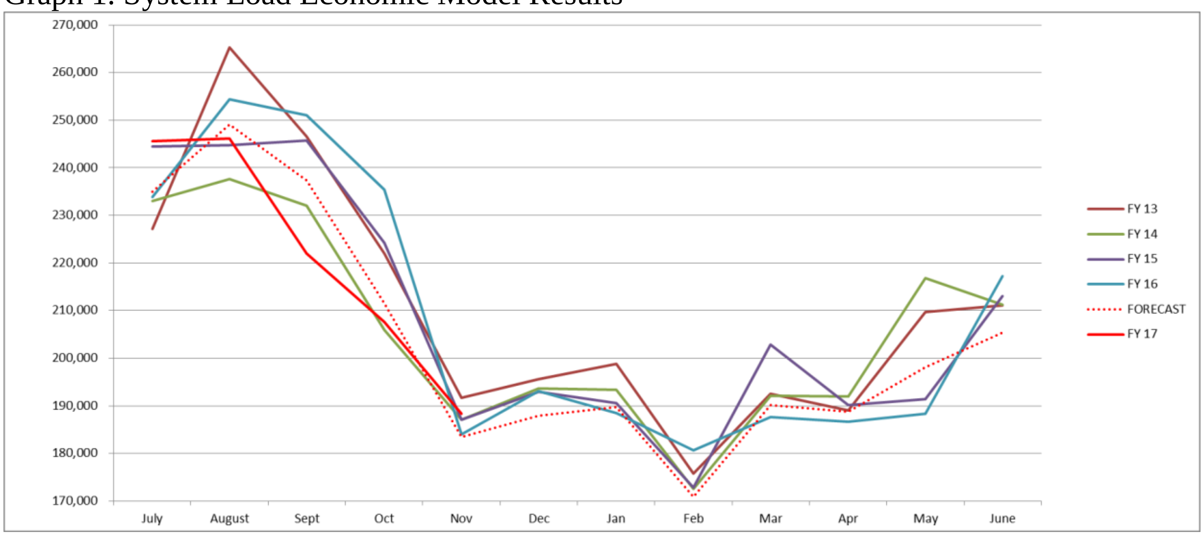

Table 1. Percent Difference of Forecast and Actuals

Month	2013	2014	2015	2016	2017	AVERAGE
July	-3%	-1%	4%	0%	4%	0.7%
August	6%	-5%	-2%	2%	-1%	0.1%
Sept	4%	-2%	3%	5%	-7%	0.7%
Oct	5%	-3%	6%	10%	-2%	3.2%
Nov	4%	2%	2%	0%	3%	2.2%
Dec	4%	3%	3%	3%		3.0%
Jan	5%	2%	0%	-1%		1.5%
Feb	3%	1%	1%	5%		2.6%
Mar	1%	1%	6%	-1%		1.8%
Apr	0%	2%	1%	-1%		0.3%
May	6%	9%	-4%	-5%		1.3%
June	3%	3%	4%	5%		3.6%
Total	3.08%	0.80%	2.10%	2.14%		1.8%

I(b). **Peak Demand Forecast**

APU uses load factor methodology to develop the City's peak demand forecast. The load factor is calculated by taking the total demand for each month and dividing it by the month's respective peak demand. The historical average load factor is calculated for each month for the most recent five years and is applied to the system load forecast developed in I(a) to develop the Peak Demand forecast. It should be noted that APU has also developed an econometric model for Peak Demand forecasting, but during testing determined that the load factor method was the more reliable model.

Table 2. Historical Load Factor

Month	2013	2014	2015	2016	2017	AVERAGE
July	68%	67%	66%	69%	62%	66%
August	68%	60%	65%	65%	63%	64%
Sept	63%	59%	59%	60%	58%	60%
Oct	57%	72%	62%	59%	50%	60%
Nov	67%	70%	66%	79%	62%	69%
Dec	78%	77%	88%	78%		80%
Jan	80%	73%	79%	78%		77%
Feb	80%	77%	72%	69%		74%
Mar	75%	76%	68%	75%		74%
Apr	77%	66%	62%	68%		68%
May	58%	55%	61%	75%		62%
June	64%	74%	66%	54%		64%

Peak Demand Forecast Calibration

The peak demand forecast is validated by calibrating the model to previous year's actual consumption data. APU performed forecast accuracy tests to actual data for 2013 through 2016. The peak demand forecast accuracy to predict peak demand by month was 0.3% to 3.5%. The annual peak accuracy was in the range of -1% to 5%.

Table 3. Peak Demand Forecast Annual Accuracy Results

	Peak	% Difference
FY 13	542	-2%
FY 14	549	-1%
FY 15	578	4%
FY 16	584	5%
FY 17	562	2%
AVERAGE	563	2%
FORECAST	*553*	

I(c). Customer Class Forecast

The Customer Class forecast is derived from allocating historical customer class percentages from the net system load estimate. The net system load is the total system load forecast in I(a) adjusted for distribution losses, which have historically been 3.5% of total system energy consumption. The average class proportions are calculated with five-year historical data. Currently, APU estimates customer class proportions to be 42% Industrial, 33% Commercial, 24.95% Residential and 0.05% Street Lighting and Other.

Planned energy growth and reductions for each customer class which are expected to impact energy consumption are incorporated to each class category to develop the Customer Class forecast. For example, APU anticipates a construction expansion project will increase load by 4GWh in 2017. The commercial class forecast will be increased by 4GWh to accommodate this expansion. Likewise, each customer class will be reduced to accommodate expected solar instillation and energy efficiency programs. Table 4 has a detailed list of anticipated developments that are expected to impact load.

Table 4. Load Growth and Reduction Projects

SYSTEM ENERGY GROWTH	SYSTEM ENERGY REDUCTION
Disney Expansion	Kaiser Fuel Cell
ARA Expansion (Hotels)	Commercial Solar
Canyon Business Center	Residential Solar
Platinum Triangle	Disney Parking Lot EE
Convention Center	Demand Response/ EE
Anaheim Concourse	
Norcal (Coka Cola)	

To summarize, the Customer Class Forecast is developed as follows:

a) System load econometric results – 3.5% distribution loss = Net Load
b) Net Load x Customer Class Percentages = Average Class Proportions
c) Average Class Proportions +/– Load Growth and Reduction Projects = Customer Class Forecast

II. Energy and Peak Loss Estimates

APU does not estimate losses by customer class. APU calculates an annual distribution loss estimate as the difference between the system forecast and the sum of the customer class forecasts. This approach has worked with a varying degree of success, and is prone to changing loss percentages over the length of the forecast as the two sets of energy estimates diverge or converge. Historically, APU's distribution loss percentage averages 3.5%. In this forecast, APU adjusted the monthly system energy forecast so that its annual sum is approximately 3.5% greater than the annual sum of all customer classes. By targeting our loss percentage to our historical 3.5%, we have allowed our two sets of energy forecasts to be compatible with one another and maintained the monthly and seasonal variations of the respective forecast results.

APU's transmission losses, assumed to be 3% of the energy produced by our generation resources, have been added to the peak forecast presented in this data request. All transmission losses occur outside of APU's distribution system.

III. Historical Forecast

Historically, the APU System and Retail demand forecasts over the last nine years have been within 2.34% accuracy (on average). The data is listed in GWh and percentage in Table 6.

Table 5. Historical System and Retail Load Forecast

FY Ending	Forecast System	Actual System	Difference	Forecast Retail	Actual Retail	Difference	Type of Forecast
2016	2,464	2,501	1.47%	2,378	2,401	0.98%	Econometric
2015	2,447	2,500	2.13%	2,362	2,398	1.53%	Historical Data
2014	2,446	2,465	0.78%	2,375	2,376	0.07%	Historical Data
2013	2,484	2,525	1.65%	2,397	2,417	0.84%	Historical Data
2012	2,508	2,473	1.42%	2,422	2,379	1.79%	Historical Data
2011*	2,627	2,458	6.87%	2,536	2,371	6.98%	Historical Data
2010	2,627	2,529	3.84%	2,534	2,452	3.31%	Statistical Data
2009	2,666	2,598	2.62%	2,572	2,534	1.49%	Statistical Data
2008	2,701	2,694	0.24%	2,607	2,597	0.38%	Statistical Data
Average			**2.34%**			**1.93%**	

**Note: 2011 was an anomaly. In 2011, the City experienced lower than expected temperatures and lower loads in the commercial and industrial sector, as a result of customers leaving the City. Overall, on average the temperature was 4.5 degrees lower than the previous year. We had forecasted new Developments in the City that were delayed and eventually never built, which impacted our forecasted numbers.*

V. Additional Forecasting Information

Economic and Demographic Data

The City of Anaheim is a fully developed Orange County suburb with historically consistent growth, median income level and employment rate. APU tested various economic models for efficiency, and determined the inclusion of forecasted economic and demographic figures leads to increased variability of the models and resulted in overly optimistic load growth estimations. As a result, APU does not include economic or demographic information into its forecast at this time. However, APU does include planned developments which are expected to impact load as adjustment constraint after the econometric estimation, as discussed in section I(a).

Energy Efficiency and Demand Side Management

APU adjusts the econometric results from the system load forecast in I(a) to include energy efficiency and demand side program forecasts. A 10-year forecast of energy efficiency was developed by Navigant Consulting as part of the statewide Energy Efficiency Potential Forecast for California's Publicly Owned Utilities. This report was submitted to the CEC on March 15, 2017, and the results are included in form 3.2.

APU is currently developing a one-year pilot residential demand response program which will be based on behavior demand response. This small-scale program is scheduled to be launched in the third quarter of 2017 and is not expected to impact peak demand. During the pilot period, APU will assess enrollment, customer participation, and actual performance during program events. Based on the outcome of the pilot program, APU will evaluate the feasibility of an expanded demand response program and may determine appropriate estimates of peak impacts for the 2019 IEPR.

Climate Change and Electrification

At this time, APU does not have an independent climate change forecast rather, these factors are embedded in the data used to determine the base load energy forecast. APU is currently developing an electrification forecast and this forecast methodology should be available for the next IEPR filing.

Local Private Supply Estimates

APU gathers local private supply data including fuel cell and photovoltaic instillation capacity data from SB-1 and City permit applications. Energy is estimated by capacity size and a capacity factor of 18% - 30%. This data is reported on forms 1.7a and 1.7c. APU applies a linear trend of historical instillation to forecast growth, and reduces the forecasted growth rate from the system load forecast in I(a).

Appendix 1: Economic Model Results

Linear regression			
	Number of obs	=	51,543
	F(36, 51506)	=	4312.64
	Prob > F	=	0.0000
	R-squared	=	0.7593
	Root MSE	=	31.228

load	Coef.	Robust Std. Err.	t	P>|t|	[95% Conf.	Interval]
temp	1.161544	.0476665	24.37	0.000	1.068117	1.254971
hol	-42.56586	.3997094	-106.49	0.000	-43.3493	-41.78243
hourday						
1	-19.55569	.6480023	-30.18	0.000	-20.82578	-18.2856
2	-32.57679	.648941	-50.20	0.000	-33.84873	-31.30486
3	-40.53517	.6565184	-61.74	0.000	-41.82196	-39.24839
4	-43.79113	.6634053	-66.01	0.000	-45.09141	-42.49084
5	-39.59933	.665293	-59.52	0.000	-40.90331	-38.29535
6	-23.38366	.6832213	-34.23	0.000	-24.72278	-22.04454
7	-2.281934	.7752369	-2.94	0.003	-3.801406	-.7624614
8	11.41311	.8078583	14.13	0.000	9.829704	12.99653
9	23.90597	.8086479	29.56	0.000	22.32102	25.49093
10	35.88353	.8601649	41.72	0.000	34.1976	37.56947
11	45.01769	.946508	47.56	0.000	43.16252	46.87285
12	51.68065	1.055048	48.98	0.000	49.61275	53.74855
13	54.98878	1.151027	47.77	0.000	52.73275	57.2448
14	59.57438	1.229975	48.44	0.000	57.16362	61.98514
15	62.35194	1.274424	48.93	0.000	59.85406	64.84983
16	62.2774	1.275841	48.81	0.000	59.77673	64.77806
17	60.15601	1.197363	50.24	0.000	57.80916	62.50285
18	61.68806	1.059471	58.23	0.000	59.61149	63.76464
19	59.16987	.9311568	63.54	0.000	57.34479	60.99495
20	59.63239	.8287198	71.96	0.000	58.00809	61.25669
21	58.2196	.7506197	77.56	0.000	56.74837	59.69082
22	45.92739	.7052316	65.12	0.000	44.54512	47.30965
23	23.8641	.6612093	36.09	0.000	22.56812	25.16007
month						
2	-1.126174	.5444339	-2.07	0.039	-2.193269	-.0590777
3	-1.838936	.5217147	-3.52	0.000	-2.861502	-.8163696
4	1.715511	.6498307	2.64	0.008	.4418368	2.989186
5	2.296774	.6529719	3.52	0.000	1.016943	3.576606
6	18.5192	.7484615	24.74	0.000	17.05221	19.98619
7	39.005	.938415	41.56	0.000	37.16569	40.8443
8	52.93442	1.016546	52.07	0.000	50.94198	54.92686
9	48.28731	1.046152	46.16	0.000	46.23684	50.33778
10	18.5315	.754581	24.56	0.000	17.05251	20.01048
11	-3.751552	.5699521	-6.58	0.000	-4.868664	-2.63444
12	3.623688	.6186604	5.86	0.000	2.411107	4.836268
_cons	174.0104	2.708937	64.24	0.000	168.7009	179.32