AUSTIN ENERGY'S TARIFF PACKAGE:	§	
2015 COST OF SERVICE	§	**BEFORE THE CITY OF AUSTIN**
STUDY AND PROPOSAL TO CHANGE	§	**IMPARTIAL HEARING EXAMINER**
BASE ELECTRIC RATES	§	

AUSTIN ENERGY'S SECOND SUPPLEMENTAL RESPONSE TO NXP SEMICONDUCTORS' AND SAMSUNG AUSTIN SEMICONDUCTOR, LLC'S FIRST REQUEST FOR INFORMATION

Austin Energy ("AE") files this Second Supplemental Response to NXP Semiconductors' and Samsung Austin Semiconductor, LLC's (collectively, "NXP/Samsung") First Request for Information.

Respectfully submitted,

LLOYD GOSSELINK ROCHELLE & TOWNSEND, P.C.
816 Congress Avenue, Suite 1900
Austin, Texas 78701
(512) 322-5800
(512) 472-0532 (Fax)
tbrocato@lglawfirm.com
hwilchar@lglawfirm.com

THOMAS L. BROCATO
State Bar No. 03039030

HANNAH M. WILCHAR
State Bar No. 24088631

ATTORNEYS FOR AUSTIN ENERGY

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of this pleading has been served on all parties and the Impartial Hearing Examiner on this 11th day of March, 2016, in accordance with the City of Austin Procedural Rules for the Initial Review of Austin Energy's Rates.

HANNAH M. WILCHAR

749/11/7052533.1

NXP/Samsung1-29. Please provide workpapers supporting any weather normalization of energy or peak demand proposed by Austin Energy.

ANSWER:

The weather normalization of Austin Energy's Peak Demand is based on model simulation similar to the weather normalization process of AE's energy sales (See Attachment 1 to AE's Response to NXP/Samsung 1-29).

Austin Energy's Peak Demand model specification is described in AE's Load Forecast Process documentation in compliance with NERC requirements (Supplemental Attachment 1).

Regression Model: Peak_MW_HTD

	A	B	D	E
1	**Model Statistics**		**Forecast Statistics**	
2	Iterations	9	Forecast Observations	0
3	Adjusted Observations	179	Mean Abs. Dev. (MAD)	0.00
4	Deg. of Freedom for Error	160	Mean Abs. % Err. (MAPE)	0.00%
5	R-Squared	0.974	Avg. Forecast Error	0.00
6	Adjusted R-Squared	0.971	Mean % Error	0.00%
7	AIC	8.40	Root Mean-Square Error	0.00
8	BIC	8.74	Theil's Inequality Coefficient	0.0000
9	F-Statistic	328.037	-- Bias Proportion	0.00%
10	Prob (F-Statistic)	0.0000	-- Variance Proportion	0.00%
11	Log-Likelihood	-987.16	-- Covariance Proportion	0.00%
12	Model Sum of Squares	23,856,659.40		
13	Sum of Squared Errors	646,449.13		
14	Mean Squared Error	4,040.31		
15	Std. Error of Regression	63.56		
16	Mean Abs. Dev. (MAD)	47.48		
17	Mean Abs. % Err. (MAPE)	2.53%		
18	Durbin-Watson Statistic	2.022		
19	Durbin-H Statistic	#NA		
20	Ljung-Box Statistic	28.45		
21	Prob (Ljung-Box)	0.2415		
22	Skewness	-0.002		
23	Kurtosis	3.211		
24	Jarque-Bera	0.331		
25	Prob (Jarque-Bera)	0.8476		

Data / DStat / Corr / Coef / MStat / Err

Supplemental Attachment 1: AE's Load Forecast Process documentation

Prepared by: JL
Sponsored by: Mark Dombroski

749/11/7052533.1

5. Attachment A – Assumptions, Methods, Handling of Uncertainties in the Forecast of Aggregated Peak Demand & Net Energy for Load

5.1 Key Assumptions

- Normal Weather calculation based on FY2004-2013 (10 Year) historical dry bulb
- CDD/HDD dry bulb temperature breakpoints pegged at 65/55 F
- Historical/Normal Revenue Month CDD/HDD are based on lengthy "Billing Cycle Weighted" process enhancing the effectiveness of the SAE models used to estimated Residential and Commercial Sector Sales.
- Economic parameters utilized in the Residential, Commercial, and Industrial Sector Sales forecasts are based on latest Travis County Projections by Perryman Group and Woods&Poole Economics.
- DSM Peak Demand & Energy Savings are based on historical performance and future goals as provided by AE's Energy Efficiency Group.
- Future DSM Savings are integrated into the forecast using industry accepted methodology.

5.2 Peak Demand Model Specification

The planned Resource Peak Demand requirements ($ResourcePeakMW_{y,m}$) in forecast $year_y$, $month_m$ is specified as:

$$ResourcePeakMW_{y,m} = PeakMW_{y,m} - DSMAdjMW_{y,m}$$

where:

$PeakMW_{y,m}$ - Peak One Hour MW Demand Regression Model estimates calibrated to utility trends before any DSM Direct Load Control (DLC) deployments in forecast year $_y$, month $_m$

$DSMAdjMW_{y,m}$ - DSM MW Savings [includes DSM Active Load Control (ALC) Program deployments] Adjusted for trend in forecast $year_y$, $month_m$

The functional specification of the Peak One Hour MW Demand Regression Model is expressed as follows:

$$PeakMW_{y,m} = f(\,ExtremeDayTemp_{y,m}\ ,\ NTS_{y,m})$$

where:

ExtremeDayTemp $_{y,m}$ - Peak Day Extreme Max/Min Temperature in forecast year$_y$, month$_m$

NTS $_{y,m}$ - AE's Net-to-System Generation or *Net Energy for Load* Requirements in forecast year y, month m

In regression model form, the Peak One Hour MW Demand model is specified by the following equation.

$$\begin{aligned} PeakMW_{y,m} = a + b_1NTS_{y,m} &+ b_2NovHDD_{y,m} + b_3DecHDD_{y,m} + b_4JanHDD_{y,m} + b_5FebHDD_{y,m} + \\ & b_6MarHDD_{y,m} + b_7FebCDD_{y,m} + b_8MarCDD_{y,m} + b_9AprCDD_{y,m} + \\ & b_{10}MayCDD_{y,m} + b_{11}JunCDD_{y,m} + b_{12}JulCDD_{y,m} + b_{13}AugCDD_{y,m} + \\ & b_{14}SepCDD_{y,m} + b_{15}OctCDD_{y,m} + b_{16}NovCDD_{y,m} + b_{17}TrendVar + \varepsilon_m \end{aligned}$$

where:

NovHDD $_{y,m}$, DecHDD$_{y,m}$, JanHDD$_{y,m}$,FebHDD$_{y,m}$,MarHDD$_{y,m}$ - Peak Day Min. Dry Bulb Temperature Heating Degree-Days for the months of November, December, January, February, and March in year$_y$, month$_m$, based on 55 F heating breakpoint temperature.

FebCDD $_{y,m}$, MarCDD$_{y,m}$, AprCDD$_{y,m}$, ..., ,NovCDD$_{y,m}$ - Peak Day Max. Dry Bulb Temperature Cooling Degree-Days from the months of February till October in year$_y$, month$_m$, based on 65 F cooling breakpoint temperature.

TrendVar - Linear Time Trend variable

The NTS $_{y,m}$ model variables in the forecast horizon are regression model estimates based on revenue month sales as independent variables.

In general, peak demand is coincident to high extreme temperature occurrences from March to November. Annual Peak One Hour Demand typically occurs on August at a coincident normal extreme temperature of 103 °F. During the winter months of December, January, and February, monthly Peak Demand is coincident to low extreme temperature.

The Peak Demand Regression Model is well behaved exhibiting a high degree of correlation.

5.3 Net Energy for Load Model Specification

AE's Net-Energy for Load modeling is equivalent to AE's Net-to-System (NTS) Generation Requirements modeling. It is estimated using a statistical regression model. Modeling specification is based on the premise that AE's Monthly NTS Generation Requirement in a given month is the sum of the Current Revenue Month Sales accrued in the current month adjusted for system losses and the Next Revenue Month Sales accrued in the current month adjusted for system losses.

In regression model form, the monthly NTS Generation model for the base case scenario is specified by the following equation.

$$NTS\_GWh_{y,m} = c_1 Sales\_GWh_{y,m} + c_2 Sales\_GWh_{y,m+1}$$

where:

$NTS\_GWh_{y,m}$ - NTS Generation estimate for the current month in GWh

$Sales\_GWh_{y,m}$ - Revenue Month Sales for the Current month in GWh

$Sales\_GWh_{y,m+1}$ - Revenue Month Sales for the Next month in GWh

The full regression model specification for the whole year consists of 24 monthly explanatory variables (two for each month). Revenue Month Sales in the forecast horizon are adjusted for DSM Energy Savings above trend.

The adequacy of this modeling approach is directly hinged on the accuracy of the Revenue Month Sales modeling. Central to the development of the Revenue Month Sales Modeling is the proper modeling of weather impacts to Austin Energy's peak load and daily energy requirements. A significant effort of the development was spent on analyzing AE load/weather relationships resulting in the development of monthly historical and normal Billing Cycle Weighted HDD/CDD. In the "Billing Cycle Weighted" process, each Billing Cycle CDD/HDD is calculated based on AE's historical/planned meter reading schedules and historical/normal dry bulb temperatures and is then weighted for the revenue month based on KWHR Sales aggregates of each Billing Cycle Group to finally come up with the revenue month CDD/HDD.

Revenue Month Sales Models are implemented by sector. Highlights of each sector modeling are as follows:

- The Residential Sector Sales Forecast utilizes the Residential SAE Model which models average Residential Customer Consumption. Residential Sector Energy Sales is then calculated using customer count data from the Residential Sector Customer Count forecast.
- The Commercial Sector Sales Forecast utilizes the Commercial SAE Model which models the aggregate Commercial Sector Energy Sales based on EIA's Annual Energy Outlook (AEO) for the West South Central region.
- The Industrial Sector Sales Forecast combines the results of an Industrial Econometric Model which accounts for small to medium industrial customer growth expansions and a

Discrete Expansion Model which accounts for very large customer expansions, e.g., chip fabrication plants (FABs) and large data centers (DCs).

Residential, Commercial, and Industrial Sector Sales in the forecast period are adjusted for new DSM Program Energy Savings above historical trend. Thus, the resulting Net-Energy for Load (NTS) forecast values are generation estimates which take into account the impacts of new DSM Program Energy Savings.

The Net Energy for Load (NTS) Regression Model is well behaved exhibiting a high degree of correlation.

5.4 Handling Forecast Uncertainties

To address forecast uncertainties due to weather, realization rates of New DSM Savings, and economic conditions, AE System sales, generation, and peak demand forecast projections are run for each the following weather scenarios:

- Extreme Weather
- Mild Weather

The Extreme Weather Scenario is a simulation of the current Base Case Forecast Scenario coupled with extreme warm/hot weather in spring, summer and fall weather conditions (March to November) and very cold winter weather conditions in December, January and February. For the current normal weather reference period, spring/summer/fall daily weather is defined as the average of the highest three peak days (ranked and average by month) while winter daily weather is defined as the average of the lowest three peak days (ranked and average by month). DSM impacts are pegged at base level of DSM savings.

The Mild Weather Scenario is a simulation of the current Base Case Forecast Scenario coupled with mild weather in spring, summer and fall weather conditions (March to November) and very warm winter weather conditions in December, January and February. For the current normal weather reference period, mild weather spring/summer/fall daily weather is defined as the average of the lowest three peak days (ranked and average by month) while mild winter daily weather is defined as the average of the highest three peak days (ranked and average by month). DSM impacts are likewise pegged at base level of DSM savings.