AUSTIN ENERGY YOUR ELECTRIC RATES

Rate Review
Responses to Requests for Information and Questions

For Questions Received following the Electric Utility Commission Meeting on September 19, 2011

Released: September 28, 2011

Rate Review -
Response to Request for Information

REQUEST NO.: Addendum to CmDay1

REQUESTED BY: Commissioner Barbara Day

DATE REQUESTED: 9/6/2011
RESPONSE FILED: 9/23/2011

REVENUE REQUIREMENT/COST OF SERVICE
CmDay1.20 Refer to Table 3.1 [page 52-53]. For each line item that raises cost of service/revenue requirement, show the dollar and percentage amount of the increase proposed to be collected from the residential class under each of Austin Energy's proposed options, A-D.

Response:
The following is the dollar and percentage amount of the increase proposed to be collected from the Residential class:

Adjustment	Total Adjustment	Amount Allocated to Residential Class	Percentage
Off-System Sales Revenue[i]	$35,130,256	$14,466,307	41.2%
Reserve Fund Contributions	$22,677,528	$9,157,587	40.4%
Interest & Dividend Income	$9,804,953	$4,100,406	41.8%
Transmission Expense	$7,437,633	$2,810,738	37.8%
STP & FPP O&M	$4,766,893	$2,222,470	46.6%
SHEC O&M	$4,147,447	$1,707,879	41.2%
FPP Scrubber O&M Expense	$2,433,504	$1,002,093	41.2%
Metering Expense	$2,047,526	$1,819,229	88.9%
Rate Review Expense	$1,292,907	$445,724	34.5%
Franchise Fees	$1,123,778	$482,888	43.0%
Uncollectible Accounts	$1,020,593	$921,729	90.3%
Update Other Revenue	$19,807	$8,156	41.2%
New Building Lease	$517,778	$312,781	60.4%

Options A-D are revenue neutral and each are designed to collect the class revenue requirement.

Notes:

- Non- Electric Revenue and Expense: when these expenses are netted together, there is an overall decrease to the revenue requirement.
- Normalization of Load and Resources: Revenue Requirement is reduced by $42,146,544 and FY2009 Rate Revenue increased by $51,808,425.
- Service Area Street Lighting is an adjustment to the FY 2009 Rate Revenue, not the Revenue Requirement.

[i] Off-System sales are included in the revenue requirement determination. Other Revenue identified in FY09 as off-system sales were removed from the revenue requirement calculation. See response to CmDay1.7.

Rate Review –
Response to Request for Information

REQUEST NO.: CmFath1

REQUESTED BY: Commissioner Shudde Fath

DATE REQUESTED: 9/6/2011
RESPONSE FILED: 9/14/11, revised 9/28/11

CmFath1.1
Excerpt from calendar year 2009 bill frequency schedule prepared by Bob Dailey in Sept. 2010:

0-500 kWh customers	105,033	(33.0% of total bills)
501-1000 kWh customers	106,580	(33.5% of total bills)
1001-2000 kWh customers	78,950	(24.8% of total bills)
2001-3000 kWh customers	19,554	(6.1% of total bills)
3001-plus kWh customers	8,297	(2.6% of total bills)
Total	318,414	

Please prepare a Residential Rate Design schedule, including percentage impacts, from the following proposal:

Minimum Bill $20.00 (pays for about 115 kWh)
Customer Charge $12.00
Electric Delivery $ 0.00
Energy Charge (includes current fuel charge) for both
Summer Period and Non-Summer period

0-500 kWh	6.948 cents (existing rate)	33.0% of bills
501-1000 kWh	*	33.5% of bills
1001-2000 kWh	*	24.8% of bills
2001-3000 kWh	*	6.1% of bills
3001-plus kWh	*	2.6% of bills

and add the four new charges in AE's four rate options.
*Using Austin Energy Option B's steep tiers as a guide, calculate rates for these four blocks.

Response: At this time, Austin Energy is not prepared to commit resources to running additional residential rate design scenarios. Austin Energy has proposed 4 residential rate design options and will discuss alternative scenarios with the Electric Utility Commission at a later date.

Rate Review –
Response to Requests for Information

REQUEST NO.: MS1

REQUESTED BY: Mike Sloan

DATE REQUESTED: 9/19/2011
RESPONSE FILED: 9/28/2011

MS1.1. Please summarize the "all-in" cost of different energy sources used to serve energy needs in Austin (such as coal, gas, nuclear, wind, biomass, energy efficiency programs, solar incentive programs, etc.) on the basis of revenue requirement per MWh of energy supplied or saved. Note: Similar data was supplied the Generation Planning Task Force in 2009 in the form of ranges of costs.

Response: Please see the following information located in the full-length Rate Analysis and Recommendations Report:

- Page D-55 and D6-8 for production expenses
- Workpaper 5.3 – Debt, pages D-197 through D-202 for interest expenses
- Workpaper 44 - PCR, pages D-293 through D-294 for Production MWh

Energy Efficiency program lifecycle cents/kWh are in the report, "DSM Performance Measures, Fiscal Year 2008-2009", page 24. This report can be downoloaded at the the Austin Energy Rate Review web site and is titled "2009 Demand-Side Management Performance Meausres" at the top of the educational materials box at www.rates.austinenergy.com/rrresources.

Rate Review –
Responses to Questions and Requests for Information

REQUEST NO.: LC4

REQUESTED BY: Lanetta Cooper, Texas Legal Services Center

DATE REQUESTED: 9/20/2011
RESPONSE FILED: 9/28/2011

LC4.1 With reference to p. 20 of 296 (AE Rate Analysis Recommendations Report D-24), please answer the following:

a. General Fund Transfer costs unbundled to customer costs ($8,705,594)
   i. How much of the $8,705,594 in general fund transfer costs unbundled to customer costs was allocated to the residential customer class.
   ii. Please identify the FERC account(s) where this cost was assigned for purposes involving the calculation of the residential customer costs. (See also p. 120 of 296, Appendix D (AE Rate Analysis Recommendations Report D-120).
   iii. Please make available for review the workpapers underlying the calculations of the amounts listed in the FERC accounts listed above. If no FERC accounts were identified, please make available for review the workpapers underlying the calculations supporting the reported amounts of the various components of the "cost of service" customer charge at p. 116 of 196 (AE Rate Analysis Recommendations Report D-120) and that are set out at p. 20 of 296 (AE Rate Analysis Recommendations Report D-24).

b. General Fund Transfer costs unbundled to Distribution costs ($15,549,336).
   i. How much of the $15,549,336 in general fund transfer costs unbundled to distribution costs was allocated to the residential customer class.
   ii. What allocation(s) was (were) used to allocate these costs to the residential customer class.
   iii. How much of this cost does AE consider should be recovered within the "cost of service" wires charge and or customer charge involving the "cost of service" residential rate design.

c. General Fund Transfer costs unbundled to Transmission costs ($5,982,279).
   i. How much of the $5,982,279 in general fund transfer costs unbundled to transmission costs was allocated to the residential customer class.
   ii. How was this cost intended to be recovered in the "cost of service" residential rate design? In other words, was any of this amount considered to be by AE part of its "cost of service" customer charge or a part of AE's "wires charge."

d. General Fund Transfer costs unbundled to Production costs ($72, 762, 791).
   i. How much of the $72,762, 791 in general fund transfer costs unbundled to Production costs was allocated to the residential customer class.
   ii. What allocation(s) was (were) used to allocate these costs to the residential customer class.

iii. Please make available for review the workpapers showing the inclusion of the general fund transfer cost into each of the production cost components of costs that includes the general fund transfer allocation that was allocated as production which is reflected on AE Rate Analysis Recommendations Report: D-118 (p. 114 of 296).

Response: Please refer to the spreadsheet on the following page and see the following for each sub-question:

a.) Of the $8,705,594 of the General Fund Transfer (GFT) allocated to the Customer function, $7,495,927 was allocated to the Residential customer class. The GFT can be found in FERC 421.5. The detail showing the allocation of the GFT within the Customer function is provided on line 178, page D-113 of the full-length Rate Analysis and Recommendations Report. The total revenue requirement within the Customer function (as shown on line 198, page D-114 of the report) is then used to develop the cost of service for this function (as shown on lines 58 through 65, page D-120 of the report).

b.) Of the $15,549,336 of the GFT allocated to the Distribution function, $6,681,560 was allocated to the Residential customer class. The allocation methods used were 12NCP Primary, 12NCP Secondary, SMD Excl Primary & Trans, Weighted Cust – Meters and City-Owned Lighting [NCP stands for Non-Coincident Peak and SMD stands for Sum of Maximum Demands]. The Electric Delivery Charge and the Customer Charge contain costs associated with the GFT. Since AE is not proposing to recover all costs identified as fixed costs through the fixed charges, the amount of the GFT included within each fixed charge cannot be determined.

c.) All transmission costs, except the transmission of electricity by others (matrix costs), but including the $5,982,279 in GFT allocated to Transmission function is removed from the cost of service as it is assumed to be recovered in the regulated T-COS filing.

d.) Of the $72,762,791 of the GFT allocated to the Production function, $26,733,394 was allocated to the Residential customer class. The allocations used were Average and Excess Demand, Net Energy for Load Net GreenChoice®, and Net Energy for Load Net GreenChoice® – Summer. Detail of the GFT calculation is included as Table LC4.1 on the following page.

Table LC4.1

General Fund Transfer

	Functionalization / Sub-Functionalization: Allocation Method	Test Year	% Allocated	Classification Allocation Method	Residential Customer Class	% Allocated to Residential
Functionalization						
Production	TTRRXGFT	$ 72,762,791	70.6%		$ 26,733,394	36.7%
Transmission	TTRRXGFT	5,982,279	5.8%	see detail below	-	0.0%
Distribution	TTRRXGFT	15,549,336	15.1%		6,681,560	43.0%
Customer	TTRRXGFT	8,705,594	8.5%		7,495,927	86.1%
		$ 103,000,000	100.0%		**$ 40,910,881**	39.7%
Sub-Functionalization						
Production						
Demand Related						
Base Load Nuclear	Prod RR	$ 16,885,211	23.2%	Ave & Excess	$ 6,953,170	41.2%
Base Load Coal	Prod RR	7,444,363	10.2%	Ave & Excess	3,065,518	41.2%
Intermediate Gas	Prod RR	5,659,859	7.8%	Ave & Excess	2,330,676	41.2%
Peak Gas	Prod RR	1,249,742	1.7%	Ave & Excess	514,632	41.2%
Renewable Solar	Prod RR	752,527	1.0%	Ave & Excess	309,883	41.2%
		$ 31,991,701	44.0%		$ 13,173,881	41.2%
Energy Related						
Base Load Nuclear - Fuel	Prod RR	$ 2,130,944	2.9%	NEFL Net GC	$ 705,667	33.1%
Base Load Coal - Fuel	Prod RR	12,066,470	16.6%	NEFL Net GC	3,995,839	33.1%
Intermediate Gas - Fuel	Prod RR	14,791,170	20.3%	NEFL Net GC	4,898,130	33.1%
Peak Gas - Fuel	Prod RR	1,114,136	1.5%	NEFL Net GC - S	427,024	38.3%
Economy Purchased Power	Prod RR	2,542,552	3.5%	NEFL Net GC	841,972	33.1%
Renewable Wind	Prod RR	6,495,743	8.9%	NEFL Net GC	2,151,080	33.1%
Renewable Solar	Prod RR	1,264,120	1.7%	NEFL Net GC	418,616	33.1%
Renewable Landfill Methane	Prod RR	365,955	0.5%	NEFL Net GC	121,187	33.1%
		$ 40,771,090	56.0%		$ 13,559,514	33.3%
		$ 72,762,791	100.0%		**$ 26,733,394**	36.7%
Transmission	Trans RR	**$ -**			**$ -**	
All Transmission GFT is allocated to the regulated portion of the transmission function and assumed to be recovered in a T-COS filing.						
Distribution						
Demand Related						
Primary Subs, P&C	Dist RR	$ 7,994,664	51.4%	12NCP Primary	$ 3,103,505	38.8%
Secondary P&C	Dist RR	3,376,055	21.7%	12NCP Secondary	1,505,647	44.6%
Transformers	Dist RR	1,412,916	9.1%	SMD Excl Primary & Trans	856,669	60.6%
Services	Dist RR	(107,230)	-0.7%	SMD Excl Primary & Trans	(65,015)	60.6%
Load Dispatch	Dist RR	443,529	2.9%	12NCP Primary	172,177	38.8%
		$ 13,119,934	84.4%		$ 5,572,983	42.5%
Customer Related						
Meters	Dist RR	$ 1,542,563	9.9%	Weighted Cust - Meters	$ 1,108,577	71.9%
Direct Assignments						
AE-Owned Lighting	Dist RR	$ 886,839	5.7%	City-Owned Lighting	$ -	0.0%
		$ 15,549,336	100.0%		**$ 6,681,560**	43.0%
Customer						
Customer Related						
Customer Accounting	Cust RR	$ 3,028,824	34.8%	No. Cust Mo.	$ 2,691,082	88.8%
Customer Service	Cust RR	3,022,380	34.7%	No. Cust Mo.	2,685,356	88.8%
Meter Reading	Cust RR	1,898,039	21.8%	No. Cust Mo. - Metered	1,686,410	88.9%
Uncollectibles	Cust RR	477,537	5.5%	Uncollectible	431,626	90.4%
Key Accounts	Cust RR	278,813	3.2%	Key Acct	1,452	0.5%
		$ 8,705,594	100.0%		**$ 7,495,927**	86.1%
		$ 97,017,721			**$ 40,910,881**	42.2%

LC4.2 Please provide the workpapers for the distribution costs that were allocated under billed demand. Please include:

a. The assumptions made to derive the estimated billing;
b. Explain how, if at all, AE considered housing stock in its assumptions;
c. Explain how, if at all, AE considered appliance saturation.

Response: The sub-functionalization of Distribution expenses are shown in worksheets labeled as Distribution in Appendix D (pages D-99 through D-112 of the full-length Rate Analysis and Recommendations Report). The total revenue requirement for the Distribution function is shown on line 198 (pages D-100 and D-107 of the report). This total revenue requirement is reflected on the COS worksheets on lines 38 through 55 on pages D-120 and D-125 of the report. Any distribution costs that are identified as "Demand" in column B on page D-120 would be reflected as demand-related costs in the cost of service results.

Column E on page D-120 of the report shows the allocation basis for each sub-functionalized distribution cost. The allocator, "SMD Excl Primary & Trans" (rows 42 and 43) is similar to billed demand (SMD stands for Sum of Maximum Demands). "SMD Excl Primary & Trans," was derived from:

- Billed Demands where available from customer classes with demand charges; and
- Estimates of Billed Demands for those customer classes not charged currently for demand. Load research sample data and Automated Meter Reading (AMR) data for commercial non-demand customers were used to:
    - Calculate ratios of maximum demand to monthly energy by customer; and
    - Develop estimated billing demands by applying these ratios to the (non-demand) customers' energy.

Neither housing stock nor appliance saturations were considered in these estimates.

LC4.3 Please provide the utility system load factor for TY [Test Year] 2009.

Response: The table on the following page (Table LC4.3) was derived from information included in Work Paper 21 on pages D-232 and D-233 in the full-length Rate Analysis and Recommendations Report. That information is referenced by the line number which corresponds with the line number in the work paper.

Table LC4.3

Line #		Energy @ Gen (kWh)	Line #	Total of CPs (KW)	LF
39	Oct-08	1,014,150,817	5	2,097,000	66.2%
40	Nov-08	864,002,889	6	1,692,200	69.9%
41	Dec-08	954,354,817	7	1,832,300	71.3%
42	Jan-09	953,652,145	8	1,726,100	75.7%
43	Feb-09	789,011,819	9	1,577,500	68.5%
44	Mar-09	893,647,597	10	1,564,600	78.2%
45	Apr-09	885,206,272	11	1,820,500	66.6%
46	May-09	1,074,053,165	12	2,158,200	68.2%
47	Jun-09	1,206,827,901	13	2,351,700	70.3%
48	Jul-09	1,303,501,741	14	2,359,500	75.7%
49	Aug-09	1,353,377,411	15	2,493,400	74.4%
50	Sep-09	1,090,313,136	16	2,383,500	62.7%
	Annual	**12,382,099,708**		**2,493,400**	**56.7%**

LC4.4 Please provide the monthly utility system load factor for TY 2009.

Response: Please see table provided in response to LC4.3.

LC4.5 Please make available for review the workpapers underlying each FERC account whose amounts, in whole or in part, have been included in residential customers fixed costs in AE's cost of service study ("cos"). The workpapers should include itemized expenses.

Response: All cost of service work papers have been provided in Appendix D of the full-length Rate Analysis and Recommendations Report. Itemized expenses are not considered work papers and are maintained only in electronic format in the City of Austin accounting software system.

LC4.6 In AE's answer to TLSC Question No. LC3.3 released Sept. 16, 2011, AE provided production and transmission components to derive fixed costs. Please provide the following information:

a. What costs have not been included, if at all, in the calculated fixed winter and summer costs. (For instance, is the cost of fuel included or excluded? Are productions costs excluded in whole or in part, and if so, how was the decision made to exclude the production costs. Please address the same for transmission costs.
b. What is the breakdown of transmission costs for June-September that you have included in the fixed costs. In your answer, please describe how these costs are incurred by AE. In your description of cost incurrence, please address whether AE is charged a rate for the transmission costs and how that rate is used to calculate its transmission costs.

c. Please provide the workpapers underlying the calculations of the production costs included in the fixed costs.

Response: The cost of fuel, which is an energy-related production cost, is not captured in the fixed costs. The demand-related production costs as well as the Electric Reliability Council of Texas (ERCOT) administration fees and Austin Energy's Energy Efficiency programs are included in the production fixed costs. These costs are shown in the full-length Rate Analysis and Recommendations Report on page D-119 in Appendix D. The demand-related costs are denoted as such in column B on this worksheet. The energy-related production costs (i.e., fuel) are identified in column B of this worksheet as well. The development of the demand-related production costs is shown in the full-length Rate Analysis and Recommendations Report starting on page D-54 in Appendix D.

The net transmission revenue requirements included in the rate analysis is the transmission of electricity by others, which is allocated to Austin Energy based on its contribution to the ERCOT four summer peaks (ERCOT 4CP). These are costs charged to AE by owners of ERCOT transmission facilities for the use of the ERCOT transmission system. All other transmission costs incurred by Austin Energy are recovered in a separate regulated Transmission Cost of Service (TCOS) rate filing. The calculation of transmission of electricity by others is shown in Work Paper 32 of the full-length Rate Analysis and Recommendations Report on page D-272 in Appendix D.

LC4.7 What are AE's proposed fees for disconnection and reconnection, and for move out and move in of electric services for residential customers?

Response: AE's current fee schedule is available on-line at: AE Current Fee Schedule and Tariff. Please see page 2 of that document for the requested information. Austin Energy is not proposing any changes to those fees at this time. City Council reviews and approves fees in the annual budget process.

LC4.8 Please provide the cost studies you have performed for each of the fees identified in No. 7 above. If these studies are included in AE's ratefiling package, please identify by page and line number the location of each reference to the costs related to each fee.

Response: See response to LC4.7 above.

LC4.9 If AE has not done a cost study, please explain why it has not done so in light of its purchase and implementation of AMS equipment.

Response: See response to LC4.7 above.

Rate Review –
Responses to Questions and Requests for Information

REQUEST NO.: CmB1

REQUESTED BY: Commissioner Gary "Bernie" Bernfeld

DATE REQUESTED: 9/20/2011
RESPONSE FILED: 9/28/2011

CmB1.1 Clarify uncollectables amount on bill; how is the monthly charge determined and is there ever a true-up? Is this only for bad debt in the residential class, or in total?

Response: Austin Energy is not proposing an "uncollectables" line item on the customer electric bill so there will not be a true-up. A chart similar to the one below was presented at the September 19th Electric Utility Commission meeting.

Component	Allocator	Cost Per Month
Customer – Accounting	Number of Customer Months	$6.78
Customer – Service	Number of Customer Months	$6.76
Meter – Reading	Number of Customer Months Metered	$4.25
Uncollectibles	Uncollectibles	$1.09
Key Accounts	Key Accounts	$0.00
		Subtotal -$18.88
Meters	Weighted Customers- Meters	$2.81
		Total -$21.69

This information is drawn from the cost of service study (See Response to CmDay 1.10) and shows the cost components identified as Residential class customer costs. Austin Energy has not proposed to collect the full $21.69 in a monthly customer charge. The four residential rate options presented include two with a $10 customer charge (options B and C), one with a $15 customer charge (option A), and one (option D) with a $30 monthly charge that includes 300 kilowatt-hours (kWh) of energy. Any of these costs not recovered through the monthly Customer Charge would be recovered through the Energy Charge.

The $1.09 shown above for "Uncollectibles" is attributable to the Residential class. However, other customer classes have "uncollectible" costs attributed to them. The allocation of total "uncollectible" costs to the various customer classes is detailed on pages D-120 and D-125 of the full-length Rate Analysis and Recommendations Report. Also, see work paper WP 17 – Uncollectible, page D-225 of the report.

CmB1.2 We have been told that off-system sales cannot be accounted for in the nodal market yet any attributable amounts will net out; this does not make sense; why can we not track the off-system sales and how can you reconcile the numbers if you cannot account for it?

Response: In the nodal market, the components of system and off-system sales cannot be accounted for as all resources are dispatched into the ERCOT market. Consequently, in the cost of service study, all sales are netted against nodal purchases so that customers receive the benefit of all Austin Energy generation dispatch. Please see response to CmDay1.7.

CmB1.3 Tables 1.6 and 1.8 mentioned in the responses to Commissioner Day were not attached, please provide.

Response: These tables are in the Response to CmDay1, on pages 25 and 26 of the PDF file.

CmB1.4 Regarding the DSC [debt service coverage], we have a target of 2.0, but what latitude do we have to move towards that target in a more measured way, reducing the need for additional reserves and smoothing out the increase required from rates? This would allow us to move the rates towards the target required over time instead of in 2 or 3 major steps.

Response: Austin Energy's financial policies prescribe a 2.0X DSC at a minimum. Adherence to financial policies is monitored by the Austin City Council, external auditors, and credit rating agencies. Currently, Austin Energy is not in compliance with the DSC policy. Austin Energy's ability to remedy non-compliance has a direct impact on its ability to maintain its credit quality and favorable credit rating. According to a June 2010 U.S. Public Power Peer Study, produced by Fitch Ratings, the median DSC for "AA-" rated utilities, such as Austin Energy, is 2.94X DSC. Thus, Austin Energy's financial policy prescribing a minimum 2.0X DSC is reasonable and consistent with the DSC of other similarly rated electric utilities.

Austin Energy's revenue requirement is calculated using the cash flow methodology and, as a result, debt service coverage does not impact the revenue requirement unless the calculated debt service coverage is less than 2.0X DSC. The financial policy states that revenue requirements based on a cash flow basis must produce a minimum of 2.0X DSC. Thus, debt service coverage is an outcome of the cash flow methodology, rather than a determinant of the revenue requirement.

Austin Energy's 2 percent Revenue Cap commitment (i.e., the affordability goal) prohibits a phased-in approach to achieving the revenue requirement since the cap limits AE's ability to raise rates in the future. Therefore, AE cannot step into the revenue requirement over time. The 2 percent Revenue Cap cannot be achieved if the requested revenue requirement is not allowed.

CmB1.5 Provide clarity on difference between emergency and contingency reserves? Use of funds, limitations, etc.

Response: This clarity is provided from language found in Austin Energy's financial policies as follows:

The Emergency Reserve shall only be used as a last resort to provide funding in the event of an unanticipated or unforeseen extraordinary need of an emergency nature, such as costs related to a natural disaster, emergency or unexpected costs created by Federal or State legislation. The Emergency Reserve shall be used only after the Contingency Reserve has been exhausted.

The Contingency Reserve shall be used for unanticipated or unforeseen events that reduce revenue or increase obligations such as extended unplanned plant outages, insurance deductibles, unexpected costs created by Federal or State legislation, and liquidity support for unexpected changes in fuel costs or purchased power which stabilizes fuel rates for our customers.

In the event any portion of the Contingency Reserve is used, the balance will be replenished to the targeted amount within two years.

CmB1.6 Under the new Net Metering program structure, it is indicated that the customer will receive credit for the excess electricity produced in a given month; can we assume that credit will reflect on the next month's bill?

Response: Yes, any credit due a customer under the net metering tariff will be applied the following month.

CmB1.7 It was previously mentioned that AE has smart meters that are one way and two way in terms of communication; what are the totals of each, is there a concentration in a given rate class of one versus the other and what impact will this have on AE implementing TOU [time-of-use] across the board in the future and maintaining flexibility in terms of pricing and system control?

Response: As of August, 2011, Austin Energy has installed 110,466 1-Way Automated Meter Reading (AMR) meters and 307,854 2-Way billing meters. 1-Way meters can send communications (e.g., kWh data, outage messages, etc) to the control software (Host) system. 2-Way meters can send communications to the Host system and receive information (e.g., On-Request Reads, program updates from the Host system, etc).

All Austin Energy 1-Way meters were installed in 2002 and 2003 at residential apartment complexes. Austin Energy chose to place its first automated meters at apartments so that Austin Energy and customers could benefit from automated reads to collect multiple reads per month for automated turn-on / turn-off of service as customers move in and move out of the apartments. All remaining residential and all commercial customers have 2-Way AMR meters, which were installed between 2008 and 2011.

Austin Energy is testing the ability to collect time-of-use (TOU) data from its residential meters and is also developing a Meter Data Management System (MDMS) to store and process metered data, including TOU and interval data collected from existing meters (that could be combined into TOU data). Austin Energy's proposed TOU rate can be applied to a limited number of customers if these TOU data delivery options are not yet proved, by replacing those customers existing meters with meters already proven to collect TOU data. For system-wide implementation of TOU rates, AE needs to complete the MDMS and full functionality testing.

CmB1.8 How long will it take to gather the TOU data to help determine the merits of expanding the program?

Response: A minimum of 18 months of customer usage information under a TOU rate would need be gathered and analyzed to provide a meaningful comparison to a non-TOU rate option.

CmB1.9 The Residential Low-Income table shown on the last page of Appendix F shows a significant difference in number of bills generated in the summer vs the winter; please explain the reason and the impact on operations.

Response: The number of residential low income customer electric bills shown in Appendix F, page 2, is the number of actual bills sent in the four proposed summer rate period months (June-September) in 2009 and the actual number of bills sent in the eight proposed non-summer rate period months in 2009. This table shows slightly different information from the residential data shown on page 1 of Appendix F, which shows the sum of all 12-month bills in 2009 for that set of customers rather than breaking this information down into the summer and non-summer rate periods.

Rate Review –
Responses to Questions and Requests for Information

REQUEST NO.: AM3

REQUESTED BY: Andy MacFarlane, Data Foundry

DATE REQUESTED: 9/23/2011
RESPONSE FILED: 9/28/2011

AM3.1 Please refer to the September 16 Response to Question AM2.17.

a. Please provide a listing of types of expenses included in FERC Account 930 for an amount of $21,470,867 requested as adjusted test year expense. (See Work Paper 42 - Legislative Advocacy and Property Insurance under the heading of Legislative Advocacy.)

b. Please provide a description of Outside Services requested in the adjusted test year in the amount of $9,975,100 shown in FERC Account 923 and included on Work Paper 42 - Legislative Advocacy and Property Insurance in the amount of $10,420,298.

c. Please explain why the title of WP 42 reads "Work Paper 42 - Legislative Advocacy and Property Insurance" and refers to Source Document 52 which is entitled "Legislative Advocacy Expenses" if all of the Legislative Advocacy expenses were removed.

Response:

a) Included in Federal Energy Regulatory Commission (FERC) 930 are the following type of expenses:

- Salaries and Fringes
- Contractual Services
- Commodities
- Expense Refunds

b) Outside Services are contractual services such as Information Technology, Appraisal, Facilities, Finance, Construction, Environmental, Security, Janitorial, Temporary Employment and South Texas Project (STP) Outside Services.

c) Work Paper 42 identifies costs associated with Legislative Advocacy and Non-Electric Property Insurance for removal from the Test Year and Source Document 52 summarizes all the Legislative Advocacy Expenses excluded from the reporting period.

AM3.2 Please refer to the September 16 Response to Question AM2.22. The cost of service Page 4 of 5 leaves an adjustment of $2,331, 688 which is the total of the increase to AE because of 311 Call Center increase and amounts associated with Distributed Generation. However WP 19 shows a test year expense amount of $6,211,224. Please clarify which amount was used to develop the cost allocation and rate design.

Response: The amount used to develop the cost allocation and rate design was $2,331,688.

The $6,211,224 from Work Paper (WP) 19 is the FERC 417 balance before subtracting out the known and measurable adjustment for City Services. Please see WP 7, Appendix D, page D-205, Line 3 of the full-length Rate Analysis and Recommendations Report for the City Services adjustment.

AM3.3 Please explain why AE is proposing to base rate fuel and purchased power at this time.

Response: One of Austin Energy's recommendations for rate design was to improve transparency by unbundling costs. The cost of service study was unbundled, meaning that costs were first separated by their underlying business functions and then allocated to customer classes. This enabled Austin Energy to develop charges and rates based on the way in which the utility incurs those costs. This enhances Austin Energy assurance that it will meet its revenue requirement even when promoting energy efficiency, conservation, and self-generation, which create uncertainties in the revenue stream. Unbundling rates also creates opportunities to explore new rate options for customers.

Maintaining a clear distinction between production, transmission, distribution, and customer service is the primary reason to merge fuel and purchased power related costs into the base energy charge. This more clearly keeps production of electricity together as a separate utility function. Generation or production of electricity is one utility function that may be replaced partially or completely as new generation products (e.g, distributed generation) become available to customers. The four utility functions (production, transmission, distribution, and customer service) represent the products and services provided by the utility.

AM3.4 AE responded to AM2.7 (c) that "Changes to the Energy Adjustment will minimized or avoided by using the Rate Stabilization Reserve". Please explain in **detail** how the Rate Stabilization Fund will accomplish this.

Response: After this rate increase, the Austin City Council's Affordability Goal for Austin Energy is to keep annual rate increases at or less than 2 percent and this includes the Energy Adjustment. This goal was intended to keep rates predictable and competitive in the future which benefits customers, the communities in Austin Energy's service area, and the utility. Variable costs like those recovered in the Energy Adjustment are the primary driver that creates uncertainty. Austin Energy's goal is to fund the Rate Stabilization Reserve balance so that it is available to cover energy market increases, purchased power cost increases, or related costs when system rate increases may exceed the 2 percent affordability goal.

AM3.5 Please provide the date in September 2011 when the Council approved AE's budget and any backup materials that addressed the Rate Stabilization Reserve.

Response: September 12, 2011. The link to the City of Austin FY 2012 Proposed Budget Volume II is:
http://www.ci.austin.tx.us/budget/11-12/downloads/fy12proposed_budget_vol2.pdf .
Pages 36 and 744-747 of Volume II cover AE Financial Policies.

AM3.6 When was the Competitive Reserve Fund established and why?

a. How was it funded?
b. What was the balance of this fund at the end of the test year and the last fiscal year?

Response: The Competitive Reserve was established in the 2003-2004 Approved Budget Financial Policies of Austin Energy as part of the Strategic Reserve Fund, replacing the Debt Management Fund. The Debt Management Fund was created by City Council resolution on 12/12/1996 which reads, “The City will direct all excess electric utility cash to a debt management fund to be used to improve the competitive position of its electric utility by reducing debt and improving the debt to capital ratio.” The Competitive Reserve, as part of the Strategic Reserve Fund, was established to improve the strategic position of Austin Energy including, but not limited to, funding capital needs in lieu of debt issuance, reduction of outstanding debt, rate reductions, acquisitions of new products and services, and new technologies.

When the Debt Management Fund was renamed the Strategic Reserve Fund, the balance was unaffected. At that time, a balance of $79.4 million was in the Competitive Reserve. The balance in the Competitive Reserve at the end of the Test Year was $3.2 million. The balance of the Competitive Reserve at the end of Fiscal Year 2009-2010 was $0.

AM3.7 The September 16 responses to AM2.8 and AM2.9 were that the balances of the Rate Stabilization Fund were zero. Page 5 of 5, line 277, of the Electric Cost of Service shows an amount for the Rate Stabilization of $109,030,479 in the column titled FY 2009 Actual. Please explain what this amount represents.

Response: The responses to AM2.8 and AM2.9 on September 16 are accurate. The balance of the Rate Stabilization Fund at the end of Fiscal Year 2010 was $0 and the projected balance for the end of Fiscal year 2011 is $0.

The amount of $109,030,479 shown on line 227 of page 5 of 5 in Appendix C (as well as page D-18 and D-265 in Appendix D of the full-length Rate Analysis and Recommendations Report) is not intended to represent the ending balance for this particular reserve fund within the Austin Energy financial statements. Rather, this amount represents a flow of funds look at what the balance in each of the reserve funds would be if Austin Energy were to redistribute the sum of the ending balances in its Strategic Reserve, Repair and Replacement, Construction and Undesignated/Unrestricted Reserves.

The point of this analysis is to identify any Test Year reserve fund excess or deficiency in total (i.e., not by individual reserve fund) to be addressed in the revenue requirement via reserve contributions or withdrawals.

The Rate Stabilization Fund replaces the Competitive Reserve Fund and would work in conjunction with the proposed Energy Adjustment (see page 45 of the report).

AM3.8 Do the amounts shown on page 5 of 5 of the Electric Cost of Service for the Contingency and Emergency Funds represent FY 2009 actual?

Response: No, please see the response to AM3.7 above.

AM3.9 Does your September 16 response to AM2.13 indicate that all of the fixed and variable costs of generation are included in the energy charge and that other distributions costs are included as well?

a. If so, what would the energy charge per kWh be for each class for just the generation cost?
b. If so, how does this fit with collecting fixed cost through fixed charges?

Response: Beginning on pages D-137 and D-138 of the full-length Rate Analysis and Recommendations Report and continuing on pages D-145 and D-146 of the report please find the Total Base Rate Unit Costs section in row 377. This section shows the unit costs by customer class and cost type. For example, row 380 of D-137 shows the cost of service identified customer-related costs on a dollar per month per customer basis for each customer class. In column H of that row, is $259.10. That is the monthly customer-related costs identified in the cost of service for the Primary Voltage <3 MW class. The proposed tariff for that class (see page E-33 of the report) includes a $250.00 monthly Customer Charge. Similarly, in row 386 of page D-137 is $2.71. That is the per unit cost of distribution costs collected on a per kilowatt (kW) basis from the Primary Voltage <3 MW class. The proposed tariff for the Primary Voltage <3 MW includes an Electric Delivery Charge of $2.50.

In the example above, the proposed rate components ($250.00 per month Customer Charge and $2.50 per kW Electric Delivery Charge for the Primary Voltage <3 MW class) are less than the identified unit costs. The remaining costs not recovered through these rate components are designed to be recovered through other rate components in the Primary Service <3 MW rate, namely the Demand Charge and the Energy Charge.

As the response to AM2.13 indicates, Austin Energy's proposed rate structure more closely aligns rates with cost types than does our current rate structure.

AM3.10 In response to AM2.16, AE said to refer to CmDay 1.26 which explains that AE is now required by Financial Policy # 17 to perform a rate review at a minimum of every 5 years.

a. Why wasn't a 5 year amortization period chosen instead of the 3 year period?

b. Does AE plan another rate change in 3 years?

Response:

a) A 3 year amortization of rate case expense is reasonable because of the following:
   1. Austin Energy will manage rates on a regular basis in light of Austin City Council's goal of no more than a 2 percent rate increase per year.
   2. Austin Energy's financial policy requires a rate review at a **minimum** of every 5 years, not every 5 years (see point 1 above).

b) Austin Energy anticipates the need for a rate review in 3 years.