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| AUSTIN ENERGY TARIFF PACKAGE UPDATE—2016 RATE REVIEW | §<br>§<br>§<br>§<br>§<br>§<br>§ | BEFORE THE<br>CITY OF AUSTIN IMPARTIAL<br>HEARINGS EXAMINER |

# DIRECT TESTIMONY

# OF

# CLARENCE L. JOHNSON

## ON BEHALF OF THE

## INDEPENDENT CONSUMER ADVOCATE



MAY 3, 2016

**CITY OF AUSTIN 2016 BASE RATE REVIEW**
**BEFORE THE IMPARTIAL HEARING EXAMINER**

**DIRECT TESTIMONY OF CLARENCE JOHNSON**

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# I. STATEMENT OF QUALIFCATIONS

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Clarence Johnson. My address is 3707 Robinson Avenue, Austin, Texas 78722.

**Q. WHAT IS YOUR OCCUPATION?**

A. I am self-employed as a consultant who provides technical analysis and advice regarding energy and utility regulatory issues. My testimony sets out the position and recommendations of the Independent Consumer Advocate (ICA).

**Q. PLEASE EXPLAIN THE ROLE OF THE ICA.**

A. The City of Austin retained John B. Coffman LLC as the Independent Consumer Advocate, with the role of representing the interests of residential, small commercial, and houses of worship customers in the electric rate review process. Mr. Coffman's ICA team includes myself and Ms. Janee Briesmeister as subcontractors.

**Q. DO YOU HAVE PREVIOUS EXPERIENCE AS AN EXPERT ON REGULATED UTILITY MATTERS IN TEXAS?**

A. Yes. I have approximately 33 years of experience as a professional regulatory analyst for Texas Office of Public Utility Counsel (OPUC) and as an independent expert witness in proceedings before the Public Utility Commission of Texas (PUC or Commission), Pennsylvania Public Utility Commission, and Connecticut Department of Public Utilities.

**Q. WHAT WERE YOUR RESPONSIBILITIES AT OPUC?**

A. As OPUC's Director of Regulatory Analysis, I was the professional staff person with the primary responsibility for advising the OPUC on economic and regulatory policy issues.

My responsibilities included reviewing utility rate applications, recommending actions or positions to be taken by the Office, preparing and presenting expert testimony, and working with other experts employed or retained by OPUC to coordinate the agency's technical evidentiary positions. I also held supervisory responsibilities with respect to OPUC's technical analysis staff. In addition, my responsibilities included providing technical assistance on legislative matters.

**Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.**

A. I have a B.S. in Political Science and a M.A. in Urban Studies from the University of Houston. My graduate degree is in an interdisciplinary program offered by the University of Houston's College of Social Science which incorporated substantial training in economics, including course work in the application of cost-benefit analysis to public policy. During my 25-year tenure at OPUC, I gained experience in virtually all phases of economic review required for the ratemaking process. I was chairman of the Economics and Finance Committee of the National Association of State Utility Consumer Advocates (NASUCA) and served as a presenter for NASUCA's workshops and panels on cost allocation and rate design, Demand-Side Management (DSM) incentives, market power and electric utility competition. Also, at various times, I have undergone training in specific subjects such as electric wholesale market design, cogeneration engineering and Electric Reliability Council of Texas (ERCOT) operations. During my work over the last six years as a consultant, I have prepared reports, comments, and testimony related to electricity issues for public interest, state agency, and local government organizations. I have testified as an expert witness in over 100 utility rate proceedings. A summary of my educational and professional background is attached as Attachment A.

**Q. WHAT IS THE SUBJECT OF YOUR TESTIMONY?**

A. My testimony will address selected issues with respect to Austin Energy's ("AE" or "Company") proposed base rate change. My recommendations focus on the class cost of service study (CCOS), the implications of the CCOS results for customer class revenues, certain aspects of AE's proposed revenue requirement, class rate design, and potential impacts on future rates, as well as addressing certain AE policies and programs. This testimony does not limit the positions that the ICA may take in this proceeding before the Impartial Hearings Examiner ("IHE"). The ICA reserves the right to review other parties' positions, as well as evidence adduced in the proceeding, in order to supplement the ICA's recommendations during briefing.

## II. OVERVIEW AND SUMMARY

**Q. HOW DID THE ICA APPROACH THIS PROPOSAL TO CHANGE ELECTRIC RATES?**

A. In pursuit of its mission, the ICA independently reviewed and analyzed Austin Energy's entire proposal by on behalf of the best interests of a majority of residential, small commercial, and Houses of Worship customers. The ICA was guided by general rate-making principles set out in Austin Energy's 2011 rate philosophy white paper, particularly with regard to the stated goals of maintaining affordability for all ratepayers and ensuring that the electric rates are fair among the various customer classes.[1] The ICA was also guided by the affordability goals adopted by the Austin City Council in February 2014, stating that Austin Energy should strive for (1) overall rates that rise no more than 2 percent annually, and (2) that AE's rates remain in the lower 50 percent of rates in the State.[2]

**Q. WHAT IS AE'S PROPOSAL FOR CHANGING THE OVERALL REVENUE REQUIREMENT AND RATE DESIGN AS A RESULT OF THIS PROCEEDING?**

A. The base rate revenue requirement is $614.4 million, which does not include the projected costs for the pass-through charges (Power Supply Adjustment, Regulatory Charge, and Community Benefits Charge). AE states that its current rate structure would collect $17.5 million more than the revenue required to meet test year 2014 costs, which represents excess revenue to be returned to customers through reduced rates.[3] Austin Energy proposes that none of this excess revenue be applied to decrease the electric rates of residential and small commercial customer classes, and rather recommends that any decrease be applied to its larger commercial customers, which it claims are paying above the cost to serve those customers. Austin Energy also proposes to modify the five rate tiers for residential customers by raising the bottom tier rate and reducing the rate of the top tier.[4]

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1 Tariff Package, p. 037; Appendix B.

2 Tariff Package, Appendix F, p. 374.

3 Tariff Package, p. 021; Footnote 11.

4 Tariff Package, p. 025.

**Q. HOW DO THE ICA'S OVERALL RECOMMENDATIONS DIFFER?**

A. The ICA's review and analysis supports an overall revenue requirement reduction of $39.8 million, more than twice the level of reduction proposed by Austin Energy, as explained in Section III of this testimony. The ICA's class cost of service study also produced different results than the utility's study regarding the relative cost positions of classes, showing that the current base revenues for residential and small commercial customer classes actually exceed those classes' cost of service. Therefore, the ICA is recommending that a greater number of customers should be sharing in the overall revenue requirement reduction, including a significant electric base rate reduction for residential consumers, as explained in Section IV of this testimony.

**Q. PLEASE SUMMARIZE THE ICA'S SPECIFIC FINDINGS AND CONCLUSIONS AS SET OUT IN THIS TESTIMONY.**

Based upon its analysis and review, the ICA recommends the following findings and conclusions, which are explained herein in greater detail:

1. AE's proposed Revenue Requirement should be reduced further through several reasonable and necessary adjustments.

   a. AE's Uncollectible Expense Allowance should be normalized to reduce the effect of the ballooning bad debt in 2013 and 2014 as a result of utility billing issues and which should thus be non-reccurring, reducing this allowance by $5.855 million.

   b. The Non-Nuclear Decommissioning expense should be reduced by 48%, a $9.89 million revenue requirement reduction.

   c. With regard to Outside City Rate Discounts, the ICA recommends that for cost of service purposes, customers inside the city should be "held harmless".

d. The Power Supply Stabilization Reserve should be funded at 90 days of net power supply costs and should not be funded with net PSA balances; credits should continue to flow to customers in the PSA calculation.

e. The level of the General Transfer Fund is a decision for the Austin City Council to make on a separate track during the city's budget review process. This decision should be made with the utmost transparency, sufficient public input, and a proper balancing of public interests.

f. Economic Development and Community Programs should be treated as part of the General Fund Transfer.

2. A greater number of customers should benefit from and share in the overall revenue requirement reduction through lower electric base rates. ICA's proposal to reduce the residential base rates is supported by recommended changes to the class cost of service study.

a. The Base-Intermediate-Peak Method (BIP), as revised by ICA, should be adopted for the purpose of allocating production plant among customer classes.

b. The ICA also recommends that changes be made to the following components of the utility's class cost of service study: Production Non-Fuel O&M Expense Classification, Functionalization/Classification of A& G Account 920 (Salaries), Classification and Allocation of Transformer/Substation Investment, Allocation of Customer Service, Allocation of Meters and Services, Allocation of Customer Accounts, and Allocation of Service Initiation Revenue.

c. When these proper changes are made to the class cost of service study, it casts considerable doubt on AE's claim that a subsidy to the residential and small commercial class is embedded in current rates.

d. ICA contends that the revenue requirement decrease should be distributed broadly among the customer classes, rather than precisely linked to specific CCOS results. The base revenues for the customer classes which are far below cost—the lighting classes—should remain unchanged. The Transmission >20 MW, 85% LF class revenues should be set at cost, ensuring that other customers are not subsidizing its contract rate. Incorporating an approximate $2 million base revenue increase for that class produces a $41.8 million revenue decrease to be distributed among the remaining classes. This revenue decrease should be allocated on the basis of class shares of kWh consumption.

e. ICA agrees with AE that the current residential customer charge should remain unchanged at $10.00. ICA disagrees with AE's cost assessment for the customer charge, and opposes movement of the charge in the direction of that target.

f. The basic rate level for the lowest tier of usage for residential customers should also not be increased. After using part of the base revenue reduction for the purpose of reducing the steepness of the tier structure, any remaining residential base revenue reduction amount should be used to reduce all tiers equally. The utility should also study potential reduction in the number of tiers for residential customers inside the city.

g. The ICA does not object to AE's proposed change in its summer/winter seasonal base rate differential.

h. The ICA does not generally object to the rate design changes proposed for the small commercial customer classes [Sec. <10 kW (S1) and the lower end of the Sec. 10 – 300 kW (S2) classes]. The ICA opposes increasing the small commercial customer charges.

i. With regard to the proposal to eliminate the Houses of Worship (HOW) discount, the ICA is concerned about dramatic rate shock among HOWs, which should be avoided. ICA disagrees with moving the HOWs off the transition discount, given Austin Energy's plans to perform rate studies that might result in a more appropriate rate treatment for HOW.

j. ICA proposes that the transition for HOWs be extended—retain the cap of 13.015 cents per kWh and the practice of measuring peak usage during weekdays. Preferably, AE should absorb the discount, instead of re-allocating the cost to other customers. The transition should not end until after the planned studies have been completed and the next rate case is completed. AE should conduct further outreach to the HOWs during the study periods.

3. The ICA makes certain recommendations regarding AE policies and programs.

   a. Austin Energy should develop a plan to improve its customer satisfaction ratings, working with the Electric Utility Commission, ratepayer advocates and the public in developing, executing and monitoring the plan for improved customer satisfaction.

   b. Proposed pilot programs should be reviewed by the Electric Utility Commission and the Council, separate and apart from the budget process. Where a pilot has identified stakeholders, such as low income advocates, Austin Energy should consult these groups about pilot goals and design, prior to initiating that pilot. Pilots should be given a firm end date; no pilot should go on indefinitely or for more than two years without a comprehensive review. Austin Energy should fully develop the terms and conditions of the pilot, its goals, customer education, performance criteria, potential cross subsidies, and evaluation metrics prior to initiating a pilot.

c. With regard to the current Prepayment Pilot Program, the ICA recommends that it not be allowed to bypass consumer protections nor should it be targeted to low income customers. The ICA recommends that Austin Energy develop a collaborative of stakeholder groups, including low income advocates, to review and make recommendations on the prepayment pilot, including adoption of consumer protections equivalent to current consumer protections.

d. Austin Energy should be required to implement a "Pick Your Own Due Date" option for consumers as soon as it is technically feasible to do so, and then publicly promote this billing accommodation to its consumers.

e. Austin Energy's cost of service should be examined more frequently than every five years. Allowing for a thorough and transparent analysis of Austin Energy's cost of service every 2-3 years, if possible, is a good policy, and is much preferable to allowing rates to change over time without such a full review.

f. There should be no piecemeal changes to electric rates or rate design, outside of the already established PSA and other pass-through charges, during the time period in between this rate review and the next rate review proceeding.

g. The studies identified by AE should be completed prior to the next rate review. AE should engage the Electric Utility Commission and stakeholder groups during the study process, and AE should provide technical expertise to the EUC and stakeholder groups during these studies.

## III. REVENUE REQUIREMENT ADJUSTMENTS

**Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?**

A. I will discuss selected issues pertaining to the amount of revenues required to recover AE's reasonable and necessary cost of service. This section on revenue requirement covers how much total rate revenue is needed, while the subsequent section, on class cost of service and rate design, will cover how to divide up the total revenue requirement among customer classes.

### A. Uncollectible Expense Allowance (Account 904)

**Q. HOW MUCH DOES AUSTIN ENERGY INCLUDE FOR UNCOLLECTIBLE EXPENSE?**

A. AE's 2014 uncollectible expense in Account 904 was $20.86 million. The cost of service adjusts this amount to a test year level of $16.1 million.[5] Uncollectible expense reflects bad debt cost.

**Q. DO YOU AGREE WITH THIS UNCOLLECTIBLE ALLOWANCE?**

A. No. This amount of uncollectible expense is high by almost any standard. The allowance for uncollectible expense should represent a prospective level sufficient to recover a reasonable recurring amount of bad debt during the period that these tariffs are in effect.

**Q. HOW DO YOU EVALUATE THE REASONABLE LEVEL OF BAD DEBT EXPENSE?**

A. On an annual basis, the amount of bad debt expense can fluctuate based on factors such as economic conditions, the size of customer bills, and the utility's management and execution of billing and collection activities. In order to develop a recurring allowance for bad debt for a utility like Austin Energy, my recommendation is to normalize the uncollectible amount based upon historic uncollectible experience. This minimizes any distortions associated with non-recurring events and unusual conditions. Because the amount of uncollectible expense is related to the amount of annual revenues, my approach expresses the uncollectible amount as a ratio of AE's electric revenues.

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[5] WP-D-1.2.9.

**Q. WHAT IS YOUR ANALYSIS OF AE'S HISTORIC UNCOLLECTIBLE EXPERIENCE?**

A. The annual uncollectible expense over an eight year period is shown below. The 2015 data is unaudited and, therefore, is included only for comparison purposes. The analysis shows an average rate over five years and seven years.

(000's)

| | Uncollectibles | Revenues | Uncollectible Rate |
|---|---|---|---|
| 2015 | $8,463 | | |
| 2014 | $20,863 | 1,234,701 | 1.6897% |
| 2013 | $17,257 | 1,183,865 | 1.4577% |
| 2012 | $3,483 | 1,081,609 | 0.3220% |
| 2011 | $3,546 | 1,122,609 | 0.3159% |
| 2010 | $4,166 | 1,030,130 | 0.4044% |
| 2009 | $3,649 | 1,032,397 | 0.3534% |
| 2008 | $2,093 | 1,069,822 | 0.1956% |
| Avg Rate (7 yr) | | | 0.6770% |
| Avg Rate (5 yr) | | | 0.8379% |

**Q. USING THIS HISTORICAL EXPERIENCE, DID YOU DEVELOP A NORMALIZED AMOUNT FOR UNCOLLECTIBLE EXPENSE?**

A. Yes. The historical uncollectible rate was relatively stable until 2013 and 2014, when the uncollectible amount more than quintupled. A range for the annual allowance can be calculated based on the average uncollectible rates for the seven year and five year periods. The shorter five year period produces the larger amount, because the 2013 and

2014 uncollectible amounts comprise a greater proportion of the average. The range is $8.2 million - $10.4 million, compared to the $16.1 million requested by AE. Notably, the $8.4 million uncollectible amount for 2015 falls within this range.

**Q. IS IT LIKELY THAT THE MASSIVE UNCOLLECTIBLE INCREASE IN 2013 AND 2014 IS DUE TO EXTRAORDINARY OR UNUSUAL EVENTS?**

A. Yes. An increase of more than five-fold for a historically stable expense generally is associated with extraordinary events. And, in this case, Austin Energy incurred widespread problems in the implementation of a new IBM billing system in the 2011 – 2013 timeframe. Austin Energy documented numerous complaints about the vendor's inadequacies, and the billing issues garnered national attention.[6] More than 100,000 customers were affected by billing system errors in 2011 - 2012.[7] The errors included both under- and over-billings, as well as substantial numbers of customers who did not receive bills. Between October 2011 and January 2013, Austin Energy ceased collection activity because of uncertainty about the accuracy of bills.[8] As a result, substantial debt accumulated, with many customers accruing thousands of dollars of past due bills. Because the lack of bills and bill errors contributed to the amounts owed by customers, the City Council liberalized the deferred payment procedures. Although the billing

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[6] *Information Week*, Feb. 23, 2012, Chronology of An Outsourcing Disaster, http://www.informationweek.com/it-strategy/chronology-of-an-outsourcing-disaster/d/d-id/1102987?page_number=1

[7] *Austin American Statesman*, Feb 18, 2012, More 100,000 Austin Energy Customers Hit By Billing Errors From $55 Million IBM System, http://www.statesman.com/news/news/special-reports/more-than-100000-austin-energy-customers-hit-by-bi/nRkb5/

[8] *Austin American Statesman*, Feb. 7, 2015, Why Customers Unpaid Bills Are Piling Up At Austin Energy, http://www.mystatesman.com/news/news/local/why-customers-unpaid-bills-are-piling-up-at-austin/nj6jM/

system problems may have occurred in 2011-2013, given the potential length of deferred payment plans (up to 36 months) and the customer's ability to enter into multiple deferred payment plans, the effect of the billing system issues may have continued to affect uncollectible amounts well into 2014. This effect should diminish as the time interval lengthens since the billing problems occurred. The ballooning bad debt expense in 2013 and 2014 should not be treated as a recurring event. Therefore, normalizing the expense amount based on average historical experience is appropriate.

**Q. YOU MENTIONED THAT AUSTIN ENERGY'S REQUESTED UNCOLLECTIBLE ALLOWANCE IS HIGH BY ANY STANDARD. DO YOU HAVE ANY EVIDENCE TO SUPPORT THAT STATEMENT?**

A. Yes. The table below compares Austin Energy's requested uncollectible expense to the uncollectible cost requested in the most recent rate case of three investor-owned bundled utilities in Texas. In order to adjust for the relative size of the utilities, the uncollectible amount is expressed on a per customer basis. Austin Energy's requested uncollectible expense per customer is more than three times the other utilities' uncollectible request. The three bundled investor-owned utilities are Southwestern Public Service Co. (SPS), Entergy Texas Inc. (ETI), and El Paso Electric Co. (EPE).

| | | customers | per customer |
|---|---|---|---|
| EPE Uncollectible | 1,923,398 | 306,046 | $ 6.28 |
| SPS Uncollectible | 2,661,033 | 251,659 | $ 10.57 |
| ETI Uncollectible | 4,887,120 | 578,693 | $ 8.45 |
| AE Uncollectible* | 16,054,751 | 436,499 | $ 36.78 |

* test year adjusted

**Q. WHAT IS THE ADJUSTMENT THAT YOU RECOMMEND?**

A. I recommend using the upper end of the range for normalized uncollectible expense. This amount is $10,199,660. After known and measurable adjustment, Austin Energy utilized a test year amount of $16,054,751. Therefore, my proposed expense reduction is $5.855 million.

**Q. IS YOUR RECOMMENDATION CONSISTENT WITH COST OF SERVICE RATE MAKING?**

A. Yes. The test year concept is intended to be representative of future costs. Given the large fluctuation in uncollectible expense caused by unusual circumstances, normalizing the expense level to reflect longer term experience is reasonable. The portion of test year costs which is unrepresentative of prospective costs should have been recovered from revenues collected at the time the expense was incurred; such costs are not appropriately recovered with future revenues. This principle is inherent in historical test year rate making.[9]

**Q. IS YOUR RECOMMENDATION SUPPORTED BY REASONABLENESS CONSIDERATIONS?**

A. Yes. Even with my proposed reduction in the allowance for uncollectibles, the adjusted amount remains quite high. With the disallowance, the uncollectible expense per customer is $23.35—more than twice the uncollectible per customer cost of SPS, the highest cost investor-owned utility in the table presented above. Regardless of the potential impact of previous billing system errors, Austin Energy's management is responsible for taking action to reduce the level of uncollectible expense. Given the high amount of uncollectible expense, I anticipate that Austin Energy will attempt to manage the expense to a more reasonable level.

### B. Non-Nuclear Decommissioning

**Q. WHAT IS NON-NUCLEAR DECOMMISSIONING COST?**

A. This is the cost of decommissioning a fossil fuel generating plant at its retirement. Decommissioning cost includes both costs (such as demolition and removal of structures) and credits (sometimes called "salvage value") for recycling and selling components. For most regulated electric utilities, the depreciation rate calculation is set to explicitly recover the net of demolition/removal and salvage, which is called net salvage. In this fashion, the depreciation rates cover the cost of decommissioning over the life of the

[9] *Application of Gulf States Utilities Company for Authority to Change Rates*, Docket No. 3871, 7 P.U.C. BULL. 410 (Sept. 17, 1981). The Texas PUC adopted this discussion of cost of service ratemaking as a statement of policy.

power plant. However, AE has not included net salvage value in the depreciation rates it recovers. Given the possibility that power plants may be retired early, AE seeks an expense component to collect the amortized cost of its decommissioning request for three power plants (Decker, Fayette, and Sand Hill). AE retained a consultant, NewGen, to estimate the decommissioning cost for these plants. AE's total decommissioning cost estimate is $80 million, and the amortized annual expense is $19 million.[10]

**Q. DO YOU HAVE ANY CONCERNS ABOUT THE REQUESTED NON-NUCLEAR DECOMMISSIONING EXPENSE?**

A. Yes. I am concerned that the requested amount is excessive. AE is recovering the expense over a truncated period, rather than the normal life of plant recovery. This results in a "lumpy" payment and is not consistent with intergenerational equity, inasmuch as the total expense will be paid by consumers at the tail end of the plant's life. Furthermore, there are indications that the requested decommissioning cost estimate is on the high side. This is not surprising, since regulated utilities frequently prepare decommissioning cost estimates which are subsequently reduced by the regulatory authority. AE's own study shows that the average requested decommissioning cost is 20% - 50% or more than the average PUC approved decommissioning cost.

**Q. WHAT ARE SOME OF THE INDICATIONS THAT THE DECOMMISSIONING ESTIMATE IS ON THE HIGH SIDE?**

A. First, on the cost/kW basis tabulated in the NewGen study, AE's chosen decommissioning cost amounts are higher than both average PUC approved amounts and

[10] WP/ D-1.2.5.

utility average requested amounts. Second, the decommissioning cost estimates contain no offsets for the value of water rights or potential sale of land. The study did not consider these potential offsetting benefits associated with decommissioning.[11] Third, the study gave no offsetting value to selling working components because this was considered "too uncertain."[12] Fourth, the decommissioning estimates used contingency adders ranging from 10.7% - 30%. The Texas PUC does not permit contingency allowances greater than 10% for nuclear decommissioning,[13] and the scope and tasks for nuclear facilities are much more uncertain than for fossil plants. Fifth, the contingency adders for Sand Hill and Fayette decommissioning are not applied to salvage and recycling estimates, meaning that the contingency is applied only to positive elements of the estimates and not to negative offsets. In the Texas PUC's most recent decision on net salvage value, the Commission found that a net salvage value of -2% should be applied to all production plant.[14] This implies that depreciation must recover 2% above gross plant cost to cover decommissioning. By comparison, the Decker decommissioning cost is almost one-half of the plant's original gross cost.

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[11] AE Answer to ICA 4-6 (e) (f).

[12] AE Response to ICA 4-6 (d).

[13] PUC Subst. Rule 25.304(h).

[14] Application of Southwestern Power Co. for Change in Rates, Docket No. 43695, Order on Rehearing FOF No. 118-119.

**Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO NON-NUCLEAR DECOMMISSIONING EXPENSE?**

A. Based on the average decommissioning cost per kW approved by PUCs, as set out in Table 4 of the NewGen study,[15] I recommend reducing the total annual decommissioning expense by 48%. Schedule CJ-1 provides the details of the $9.89 million revenue requirement reduction. Given that AE's estimates are near the upper boundary of decommissioning costs, my approach balances ratepayers' interest in containing costs recoverable through rates, while mitigating intergenerational inequity.

### C. Outside City Rate Discounts

**Q. PLEASE DISCUSS AE'S PROPOSED RATE DIFFERENTIAL FOR INSIDE AND OUTSIDE CITY CUSTOMERS?**

A. The settlement of Docket No. 40627, the appeal to the PUC of AE's 2012 rate increase, included a rate discount of 5% for outside city customers. Although the settlement is not binding on subsequent rate changes, AE's current rate proposal assigns part of the revenue reduction to outside city customers in a manner that maintains outside city customers' discount off of the proposed inside city rates. The amount of the outside city discount included in the AE proposal is $5.8 million.[16]

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[15] Appendix I page 99.

[16] AE Response to HURF Request 1-1.

**Q. DOES A COST BASIS EXIST FOR THE OUTSIDE CITY RATE DISCOUNT?**

A. No. Austin Energy is not aware of any cost basis for the inside / outside city rate differential.[17] Likewise, I am not aware of any costing principle which would suggest that outside city rates should be higher than inside city rates. If anything, one might argue the opposite. My assumption is that AE has continued the outside city rate discount in order to mitigate litigation risk.

**Q. WHAT IS THE EFFECT OF THE RATE DISCOUNT ON INSIDE CITY CUSTOMERS?**

A. The outside city discount reduces the overall level of revenue reduction available in this case. In addition, the revenue shortfall produced by the discount reduces the indicated current revenues of each respective customer class. Therefore, since 94% of the revenue shortfall associated with the outside city discount applies to the residential class, the discount contributes to the supposed subsidy of the residential class indicated by the CCOS study.

**Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO TREATMENT OF THE OUTSIDE CITY RATE DISCOUNT?**

A. The outside city rate discount can be continued, as proposed by AE. For cost of service purposes, I propose that a revenue imputation should be applied to classes, imputing the level of class revenues as if outside city customers paid a revenue level corresponding to inside city service. This "holds harmless" inside city customers for the settlement negotiated with representatives of outside city customers. Presumably AE agreed to the

[17] AE Response to ICA Request 1-26.

outside city discount in order to avoid the risk that the Public Utility Commission would find the utility's revenue requirements excessive or reduce or eliminate the general fund transfer. However, it is unreasonable to force inside customers to pay higher rates as a result of the discount.

**Q. IS THIS TREATMENT SIMILAR TO REVENUE IMPUTATIONS APPLIED TO OTHER RATE DISCOUNTS?**

A. Yes. Sec. 36.007, PURA, is the provision governing rate discounts. Sec. 36.007(d) states that the allocable costs of serving customers served by discounted rates are not to be borne by the utility's other customers. In applying that provision to utilities with Sec. 36.007 discounts, the shortfall associated with the discount is imputed to the current revenues of classes containing the customers receiving discounts.

**Q. IS THIS FAIR TO INSIDE CITY CUSTOMERS?**

A. Yes. The revenue imputation ensures that the cost of the discount is paid out of AE's margin rather than forcing outside city customers to pay higher rates to support the outside city discount. This is comparable to AE's decision when it originally agreed to the discount. After the Docket No. 40627 settlement was entered, AE did not increase inside city customers' rates to pay the shortfall. This means that the cost of the discount was paid out of the utility's margin.

**D. Power Supply Stabilization Reserve**

**Q. PLEASE DESCRIBE THE PROPOSED POWER SUPPLY STABILIZATION RESERVE.**

A. Austin Energy proposes to change the Rate Stabilization fund into a "Power Supply Stabilization Reserve" and to use any funds remaining after closing the Emergency Reserve, and fully funding the Contingency Reserve for the Power Supply Stabilization Reserve.[18] Going forward, the reserve would be funded from net credit balances remaining in the Power Supply Adjustment, rather than including these as a credit in the calculation of the subsequent PSA. Austin Energy further recommends the reserve should maintain a cash balance between 90 and 120 days of Net Power Supply expenses. The purpose of the fund is to "mitigate unpredictable fluctuations in Net Power Supply costs in order to stabilize rates and meet affordability goals."[19]

**Q. IS IT REASONABLE TO HAVE A POWER SUPPLY STABILIZATION RESERVE?**

A. Yes. The ERCOT market can be volatile, producing short term price spikes. Reframing the rate stabilization fund into a power supply stabilization fund is reasonable. Such a reserve helps to insulate ratepayers from market volatility.

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[18] Tariff Package at Bates 099.

[19] Tariff Package, Bates p. 101.

**Q. DO YOU AGREE WITH THE PROPOSED LEVEL OF FUNDING IN THE POWER SUPPLY RESERVE?**

A. No. Austin Energy recommends the reserve should maintain a cash balance between 90 and 120 days of Net Power Supply expenses. This funding level is consistent with the recommendation made in the NewGen study found in Appendix I of the Master Appendices. After evaluating the risk to Austin Energy due to volatility in the ERCOT market, NewGen recommended funding a Power Supply Stabilization Reserve in the range of $110 to $160 million, equating to approximately 90 to 120 days of net power costs.[20] NewGen referred to this range as representing the "worst case scenario" and stated further: "If using the worst case scenario over the period is too conservative, an average approach yields a range between $43 million and $106 million when prorating historical costs up to the 2015 [ERCOT] price cap."[21] Analyzing potential exposure "from a different perspective", NewGen found "on average over the four-year period, cost exposure under maximum market pricing conditions that occurred at the time of the AE unit outages was approximately $110 million."[22]

I do not agree with funding this reserve based on the "worst case scenario" and assuming that all volatility will meet the ERCOT market price cap. The analysis does not appear to consider whether hedging or other contracts in the forward market could insure against simultaneous outages at STP and FPP during a period of price spikes, which is the

[20] Appendix I, Bates stamped pages 475-477.

[21] Appendix I, Bates p.475.

[22] Appendix I, Bates p. 476.

worst case event. The benefits of a stabilization fund must be balanced with affordability for ratepayers. The difference between 120 days and 90 days' net power supply costs in the reserve fund ties up tens of millions of dollars more ratepayer money, and potentially prevents customers from receiving fuel cost refunds in the future.

**Q. DO YOU AGREE WITH HOW THE PROPOSED RESERVE WILL BE FUNDED?**

A. No, not entirely. I do not disagree with moving funds from the Emergency and Contingency Reserves as described above. However, I disagree with using net credit balances in the PSA to fund this reserve, rather than including them in an over/under collection calculation. The larger the required the balance in the fund, the greater the impact of this change on ratepayers. If this approach were currently in effect, it is unlikely ratepayers would have received the 11.3% decrease in the PSA that took effect on April 1.

**Q. WHAT IS YOUR RECOMMENDATION?**

A. First, I recommend funding this reserve at 90 days of net power supply costs. This level is supported by the NewGen study findings outside of the "worst case scenario". Second, I recommend the Power Supply Stabilization Reserve should not be funded with net PSA balances; credits should continue to flow to customers in the PSA calculation. These recommendations balance the goals of stabilizing the PSA with affordability goals.

### E. General Transfer Fund

**Q. WHAT IS THE GENERAL TRANSFER FUND?**

A. As a municipally owned utility, AE is allowed by law to transfer a certain percentage of its revenues to the Austin City Council. A general fund transfer is analogous to the franchise fees and rate of return that is allowed by the PUC to be included in the calculation of the utility revenues and rates of an investor-owned utility. Unlike investor-owned utilities, these funds are then invested or spent towards purposes deemed to be priorities by an elected body that serves the public living in general service territory. AE currently pays an annual General Fund Transfer to the City of Austin in the amount of $105 million, and AE has included this amount in the proposed test year revenue requirement, the lowest amount permitted under current city council policy.[23]

**Q. WHAT IS YOUR RECOMMENDATION REGARDING THE GENERAL TRANSFER FUND?**

A. The appropriate level for the general transfer fund is a decision for the Austin City Council, and is a decision that will be made on a separate track during the city's budget review process. This is a very important input for the determination of AE's overall revenue requirement. This decision should be made with the utmost transparency, sufficient public input, and a proper balancing of public interests.

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[23] Tariff Package, p. 088.

### F. Economic Development and Community Programs

**Q. DOES AUSTIN ENERGY CONTRIBUTE TO THE CITY'S ECONOMIC DEVELOPMENT DEPARTMENT?**

A. Yes. Like other city departments, Austin Energy contributes to the City's economic development efforts.[24] $9,090,429 is collected through the customer charge.[25]

**Q. WHAT IS THE PUBLIC UTILITY COMMISSION'S TREATMENT OF ECONOMIC DEVELOPMENT EXPENDITURES?**

A. Prior to the first unbundling cost of service cases before the commencement of electric competition, the PUC directed electric utilities to limit economic development expense requests to the amounts allowed prior to competition. As with any other expense, the utility must still prove that the economic development expense is reasonable and necessary. AE's economic development expenditures are larger than most Texas electric utilities. For example, Center Point Electric's economic development program was $2.4 million in its last rate case, compared to more than $9 million for AE. AE's economic development amount is 0.77% of revenues, compared to Center Point expending 0.16% of its revenues on economic development.

**Q. DOES AUSTIN ENERGY MAKE CONTRIBUTIONS TO COMMUNITY PROGRAMS?**

A. Yes. Austin Energy describes contributions to Community Programs as "corporate sponsorships providing partnership and support to community, customer and civic

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24 Designated economic growth and redevelopment service office (EGRSO) in the CCOS study.

25 See Cost of Service Model Schedule H-5.4.

organizations and events."[26] In 2015 these contributions included entities as diverse as Ballet Austin, American Diabetes Association, Community Mentor Initiative, Clean Air Force, Texas Public Power Association, and Texas Renewable Energy Industries Association. Several programs also receive funding from other city departments.[27]

**Q. HOW DOES THE PUBLIC UTILITY COMMISSION OF TEXAS TREAT DONATIONS TO COMMUNITY PROGRAMS BY UTILITIES?**

A. The PUC by rule[28] limits the amount of advertising, contributions and donations that can be included in rates to "three-tenths of 1.0% (0.3%) of the gross receipts of the electric utility for services rendered to the public." Note this limitation includes advertising, as well as contributions and donations.

**Q. WHAT IS YOUR RECOMMENDATION?**

A. I recommend bringing greater transparency to Austin Energy's transfers to the Economic Development Department and its donations and contributions to Community Programs. As an example, Council's Austin Energy Oversight Committee received a briefing on Austin Energy's current and recent spending in these areas on February 25, 2016.[29] A review of the video and transcript of this meeting indicates members of the City Council

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[26] AE Response to ICA 2-7

[27] See both AE Response to ICA 2-7 and Austin Energy General Fund Transfer and Payments for Services presentation of February 25, 2016 to the Austin Energy Utility Oversight Committee: http://www.austintexas.gov/edims/document.cfm?id=250333

[28] Public Utility Commission of Texas, CHAPTER 25. SUBSTANTIVE RULES APPLICABLE TO ELECTRIC SERVICE PROVIDERS, Subchapter J. COSTS, RATES AND TARIFFS. DIVISION 1. RETAIL RATES §25.231. Cost of Service (b)(1)(E).

[29] http://www.austintexas.gov/department/city-council/2016/20160225-aeuoc.htm

are not fully aware of the amounts or in some cases, the purpose, of some of these expenditures that are contained in Austin Energy's budget.

At this time, I am not objecting to or proposing to eliminate expenditures for economic development or contributions to community programs. The City may legitimately decide to make these expenditures and contributions with funds generated by Austin Energy or any other city department. However, in my opinion, and consistent with the requirement that only reasonable and necessary expenses are allowed in cost of service, these are not *necessary* expenditures for providing utility service. Therefore, I recommend the Council transition toward treating Economic Develop program, donations, and contributions to community programs as part of the General Fund transfer. In this manner the economic development expenditures and donations would be clearly segregated from utility expenditures. This recommendation has no direct impact on rates since the expenditure is transferred to the GFT (unless and until the total amount of the expenditures is increased or decreased). The expenses would be clearly treated as nonutility expenses, improving transparency. When the city council establishes criteria for the size of the General Fund transfer, it should incorporate the intended budget for Economic Development expenses into that criteria.

## IV. CLASS COST OF SERVICE

### A. Overview

**Q. WHAT IS A CLASS COST OF SERVICE (CCOS) STUDY?**

A. The CCOS is a fully allocated cost study which distributes the Company's costs to customer classes. The intent of the study is to allocate costs based on cost causation, generally resulting in a portion of costs allocated on causal measures and the remainder of indirect costs following those costs. The CCOS is at best a broad benchmark for evaluating customer class cost responsibility. The CCOS can provide guidance to the regulator, but considerations other than the CCOS also are appropriate in determining the ultimate allocation of costs among customer classes.

**Q. HOW IS THE COST CAUSATION CRITERION APPLIED IN THE CCOS?**

A. Some costs are incurred directly to serve only an individual customer or set of customers. For example, substations are sometimes dedicated to serving an individual customer and can be directly assigned.

However, the provision of electric utility service is predominated by common and joint costs, which either support the overall enterprise or produce shared benefits for all or most customers. These costs often are assigned based upon indirect, and often weak, measures of causation. For example, overhead costs, such as Board of Director fees, might be allocated based upon measures as diverse as revenues, labor costs, energy sales, or demand. No single objective economic basis supports the allocation of these costs; therefore, the allocation decisions are subjective or based on rate making conventions. Ideally, the analyst selects a method that best recognizes the manner in which customer classes' characteristics contributed to the incurrence of utility investments and expenses. The manner in which a utility plans and installs an investment often informs the analyst's evaluation of causal factors related to classification or allocation of the investment.

The three major steps of the embedded cost of service study are functionalization, classification, and allocation. Functionalization is the procedure for separating costs into functional segments, such as production, transmission, and distribution. The next two accounting steps, classification and allocation facilitate the recognition of causation. The classification procedure, which pools costs into general categories of causation (i.e., demand, customer, energy), is an intermediate step in determining the allocation factors that are used to divide costs among jurisdictions and customer classes.

**Q. PLEASE DESCRIBE YOUR REVIEW OF THE CCOS STUDY PREPARED BY AUSTIN ENERGY.**

A. My testimony reviews the reasonableness of functionalization, classification, and allocation decisions within the CCOS study. AE has made the excel workbook for the model publicly available. I have made recommendations with respect to a number of class cost of service issues, and I implemented those recommendations by modifying the AE model spreadsheets. The basis for my recommendations are discussed below.

## B. Production Demand

### 1. Causal Factors for Generation Capacity Costs

**Q. WHAT ARE THE TWO MAJOR ALLOCATION METHODS APPLICABLE TO PRODUCTION PLANT?**

A. The two general types of allocation bases are annual energy use and peak demand. Although many variations of the two methods are available, the two approaches represent distinct dimensions of causation.

Peak demand represents the maximum use that occurs during a specified period of time (such as a year or a season). Peak demand measures, in theory, instantaneous maximum demand and not the time duration associated with the usage.

Average annual energy usage represents total kilowatts sales for the year. Average demand, which is annual sales divided by 8,760 hours, measures average hourly usage. The allocators for average demand and annual energy use are the same. Conceptually, average demand shows what the system hourly usage would be if no hourly peaks occurred.

**Q. PLEASE EXPLAIN THE DIMENSIONS OF CAUSATION ASSOCIATED WITH PEAK DEMAND AND ANNUAL ENERGY USE.**

A. Peak demand relates to the sizing of facilities. The megawatt capability of available generation plants constrains the level of instantaneous demand that can be accommodated. On the other hand, annual energy use and average demand pertain to costs that are affected by the duration of usage.

The relationship between peak demand and average demand is summarized by the calculation of "load factor." Load factor is average demand divided by peak demand. Load factor indicates the proportion of energy consumption which is relatively constant.

**Q. HOW ARE THESE DIMENSIONS RELATED TO THE UTILITY'S PRODUCTION COSTS?**

A. During the course of a year, the utility's operating mix and utilization of installed generating capacity changes constantly. In the prior paradigm of regulated wholesale power, the utility's control center dispatched its generation to meet the utility native load's real time demand at the lowest cost. In the new structure of the wholesale market, ERCOT dispatches all of the region's generation to satisfy supply and demand consistent with market bids. As discussed in (4) below, ERCOT's role in dispatching generation does not change the fundamental characteristics of production economics. Baseload power plants are the most economical to operate and will be used on a more or less constant basis. Peaking power plants are less efficient in meeting demand over an extended period, but are particularly well-suited to accommodating increases in demand of a short duration. Intermediate power plants have operating characteristics that lie between baseload and peaking units. If power purchases on the open market are available at a lower operating cost than the utility's own generation, the lower cost purchases will be used to displace or supplement the operation of the utility's installed generation units. The process of dispatching generation is intended to achieve a mix of generation units that minimizes running costs. In the previous wholesale structure, the utility's dispatch software identified the optimal dispatch from moment to moment. In the current ERCOT system, market clearing prices over short time intervals reveal the mix of generation units which are least costly in real time.

If a utility was concerned only with building or buying enough capacity to meet maximum demand, the Company would construct or purchase only peaking capacity because such capacity requires the lowest fixed costs. However, higher fixed costs are incurred to build or acquire baseload and intermediate capacity, because such generation is the cheapest at meeting loads of constant duration.

**Q. HOW DO ELECTRIC UTILITIES DETERMINE THE MOST ECONOMIC GENERATING RESOURCES TO ACQUIRE AND BUILD?**

A. A municipal utility such as Austin Energy will consider a number of factors in addition to the pure economics of generation technologies. The factors include environmental impact and climate change. In addition, the relative economics of available options will inform the recommendations of Austin Energy's planners. The primary planning assumption inputs for modeling future economic impacts are energy/fuel prices, forecasted system demands, ERCOT market price trends, and capital costs. Sensitivity studies can be conducted for different energy price and demand levels to evaluate the customer rate impact of various scenarios. The assumption for demand growth is most important in determining *when* new capacity is required and the energy/fuel input is most significant to determining the least cost *type* of capacity to be installed or acquired.

The economics of alternative portfolios of future generation resources will depend on critical trade-offs between each resource's capital cost and energy costs. High capital cost options have lower energy costs while less expensive capital cost options tend to have higher energy costs. Nuclear and coal capacity have very high capital costs but correspondingly low fuel costs. Gas fueled units have lower capital costs but rely upon a higher priced fuel. Even among gas plant technologies, higher capital costs are incurred to install technologies with lower heat rates.[30] Renewable technologies, such as solar, and wind, typically have a relatively high cost per kilowatt of capacity, but in return they produce zero fuel cost.

[30] Heat rate is a measure of efficiency in converting fuel into electricity; a lower heat rate is more efficient.

**Q. HOW SHOULD SYSTEM OPERATION AND PLANNING INFLUENCE THE SELECTION OF CLASS ALLOCATION FACTORS?**

A. First, demands have to be served reliably throughout the year, which points toward allocating on the basis of multiple hours of demand. Second, the allocation method should recognize that energy (or average demand) is a major determinant of the mix of installed generation resources and the economic dispatch of that generation.

The dual importance of demand and energy in developing production demand allocation methods is recognized in the National Association of Regulatory Utility Commissions (NARUC) Electric Utility Cost Allocation Manual ("NARUC CAM"):[31]

> There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption.

The NARUC CAM cites the utility system planning process as justification:[32]

> Generally speaking, electric utilities conduct generation system planning by evaluating the need for additional capacity, then, having determined a need, choosing among the generation options available to it. These include purchases from a neighboring utility, the construction of its own peaking, intermediate or baseload capacity, load management, enhanced plant availability, and repowering among others.
>
> The utility can choose to construct one of a variety of plant-types: combustion turbines (CT), which are the least costly per KW of

31 NARUC Electric Utility Cost Allocation Manual at 49.

32 *Id.* at 53.

> installed capacity, combined cycle (CC) units costing two to three times as much per KW as the CT, and baseloaded units with a cost of four or more times as much as the CT per KW of installed capacity. The choice of unit depends on the energy load to be served. A peak load of relatively brief duration, for example, less than 1,500 hours per year, may be served most economically by a CT unit. A peak load of intermediate duration, of 1,500 to 4,000 hours per year, may be served most economically by a CC unit. A peak load of long annual duration may be served most economically by a baseload unit.

**Q. WHAT IS YOUR CONCLUSION?**

A. I agree with the NARUC CAM's description, above, of the relationship between the planning and operation of generation and the allocation of generation investment costs to customer classes. Ideally, the allocation methodology should recognize the types of generation facilities, including the manner in which each type of generation technology affects customer classes' capacity utilization.

### 2. Austin Energy's Proposed 12 CP Method

**Q. WHAT PRODUCTION DEMAND METHODOLOGY IS PROPOSED BY AUSTIN ENERGY?**

A. Austin Energy proposes an allocation based on each classes' 12 monthly peak demands coincident with the ERCOT monthly peak demands (12 CP). This is different than the Average & Excess Demand (AED) method adopted in the 2011 rate proposal. AE argues that 12 CP more effectively recognizes ERCOT's centralized dispatch of generation than AED.

**Q. DO YOU AGREE THAT 12 CP IS AN IMPROVEMENT OVER THE AED METHOD?**

A. Yes. The AED method does not recognize the diversity between ERCOT and Austin Energy demands. In addition, AED does a poor job of recognizing the impact of energy on planning and operating generation capacity.[33] AED effectively allocates costs on usage in only four hours of the year. At least 12 CP recognizes the reality that reliability is a concern throughout the year, and not just in the summer months. That said, 12 CP may be better than AED, but it is still inadequate to reflect cost causation. 12 CP is a peak demand methodology and does not directly recognize the impact of energy on planning and operating generation.

**Q. WHAT IS THE MOST SIGNIFICANT DEFICIENCY OF THE 12 CP METHOD?**

A. The proposed methodology does not recognize the existence of different types of generation facilities with varying cost characteristics that are critical to the planning and operation of generation capacity. AE's method uses 12 CP to allocate a homogenous annual capacity cost to each month. In reality, generation capacity costs are not homogenous. As previously discussed, Austin Energy incurred distinctly different capacity costs to serve baseload, intermediate, and peak periods. Although energy loads are a major determinant of production plant costs, as stated in the NARUC CAM, the 12 CP method proposed by AE does not recognize the relationship between system energy use and the causation of generation investment.

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[33] Because the AED formula includes "average demand," it gives the appearance of recognizing energy. However, the algebraic effect of the AED formula largely cancels the impact of average demand. AED's recognition of energy is illusory. AED is a circuitous route to allocation on the basis of peak demand.

### 3. Base-Intermediate-Peak Method (BIP)

**Q. WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE PRODUCTION DEMAND METHOD FOR AE?**

A. My recommendation is to utilize the Base-Intermediate-Peak Method (BIP) for allocating production plant among customer classes. I have developed a variant of BIP which recognizes the specific characteristics of AE's generation investment. The NARUC CAM identifies BIP as an accepted production demand methodology which falls within the "time-differentiated" category of methodologies.[34] BIP utilizes three time periods—Base, Intermediate, and Peak hours—and is based on the premise that baseload, intermediate, and peaking generation technologies and fuel types were incurred primarily to serve each of those time periods, respectively.

**Q. ARE OTHER METHODS AVAILABLE WHICH ADDRESS THE SAME ALLOCATION OBJECTIVE?**

A. A number of energy-based and time of use methodologies are available. Some of the methods are formulaic (e.g., Average and Peak or weighted Average and Excess), and therefore easier to administer from case-to-case. But these methods do not explicitly reflect the capacity cost differentials on AE's system or the effect of operating in the ERCOT market. Some of the methods are more data intensive because they reflect hourly time of use costs (e.g., probability of dispatch method). These methods are more difficult to administer, and may not be well-suited for recognizing ERCOT dispatch. In my judgement, BIP will produce class allocation results similar to more data intensive

[34] NARUC CAM at 60-62.

time of use methods; any difference in results probably is not justified by the additional complexity of the capacity utilization models. BIP, as modified for my recommendation, represents a reasonable balance between the relative simplicity and complexity of the alternative methodologies.

**Q. PLEASE SUMMARIZE YOUR REASONING FOR RECOMMENDING BIP?**

A. First, the methodology explicitly recognizes the different types of generation technologies and fuel sources which were chosen by AE to serve the base, intermediate, and peak hours. Therefore, the method reflects the production cost causation criterion discussed in (1), above. Second, the methodology appropriately recognizes that, over the last 30 years, AE historically relied upon nuclear and coal generation to reduce total fuel cost. Third, the methodology reflects the more recent trend of using combined cycle and combustion turbine gas fired generation to meet loads of medium and short duration with the least costly capital investment. Fourth, AE has considered the BIP methodology and, therefore, is aware that it represents a reasonable methodology for the AE system. Fifth, AE's previous cost of service consultant, R.W. Beck (later called "SAIC"), recommended BIP during the public involvement (PIC) process for the 2011 rate request.[35] The consultant pointed out that BIP is consistent with the characteristics of ERCOT market dispatch.[36]

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[35] AE Response to ICA Request 7-11.

[36] R.W. Beck concluded that BIP mirrored the Probability of Dispatch method (POD) by "maintaining a link between resource dispatch and load requirements, but in a manner more consistent with the ERCOT nodal market design." Ibidem.

**Q. ALTHOUGH AE CONSIDERED BIP IN THE PREVIOUS RATE CASE, AE RECOMMENED THE USE OF AVERAGE & EXCESS DEMAND (AED). IS THIS A REASON TO REJECT BIP IN THIS RATE REQUEST?**

A. No. AE's position in the previous rate request used the BIP result to support the "±5% of cost" residential revenue criterion. So, the suggestion that BIP had no influence on the previous class revenue distribution is inaccurate. Furthermore, the 2012 rate request was based on a 2009 test year, a time period prior to the implementation of ERCOT dispatch. AE has pointed to this distinction to justify the change in its recommended method (from AED to 12 CP) in this case. In my view, BIP is a better match with ERCOT market characteristics than 12 CP alone.

**Q. PLEASE DESCRIBE THE GENERATION TECHNOLOGIES ASSIGNED TO BASE, INTERMEDIATE, AND PEAK UTILIZATION.**

A. The BIP method identifies the plant investment assignable to base, intermediate, and peak utilization.[37] The RFP WP/F-2.3.1 provides the sub-functionalization of production plant. South Texas Project (nuclear) and Fayette Power Plant (coal) are assigned as baseload, because these units are operated as much as possible throughout the year. From an economic perspective, Austin Energy's objective is to maximize the capacity factor for these two plants in order to take advantage of their low variable costs. Steam-fired gas units and combined cycle gas units at Decker Power Plant and Sand Hill Energy

[37] When AE has prepared BIP allocations, it appears that revenue requirements rather than plant investment was used for weighting the three periods. Production demand methods are considered to be generation plant allocation factors, and it is customary to assign *plant costs* to time periods, which is reflected in my formulation of BIP.

Center are assigned as intermediate generation. Typically intermediate generation will have capacity factors ranging from 20% - 50%, depending on their variable costs and market conditions. Intermediate periods frequently include shoulder demands. The gas generation categorized as "Quick Dispatch" consists of combustion turbines at the Decker and Sand Hill sites, and are assigned to Peak. As the name implies, these units can be started quickly in order to meet loads of short duration. AE has minor amounts of investment in wind and solar plant, which are properly included in the baseload category. Renewable investment is not dispatchable, but the plants share the energy characteristics of baseload generation. Solar and wind power involve relatively high capital costs per kW which are incurred in order to achieve zero fuel cost. Therefore, the capital cost provides energy value to AE's generation portfolio.[38]

**Q. PLEASE EXPLAIN HOW CLASS ALLOCATION FACTORS ARE DEVELOPED FOR BIP.**

A. The Base capacity is allocated on an energy basis, because baseload generation is operated at maximum capacity factor in order to achieve maximum energy value throughout the year. The Intermediate period is allocated partially on an energy basis and partly on the basis of 12 CP (ERCOT), because intermediate generation has a role which is a mixture of Peak and Baseload characteristics.[39] The capacity factor of these units is a

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[38] Most of AE's renewable generation is purchased and, therefore, is paid through the PCA. As a practical matter, renewable generation has little or no current effect on BIP. However, as AE constructs or installs renewable generation in the future, it will affect the baseload component of BIP.

[39] This varies from the AE method for applying BIP, which uses only 12 CP for intermediate units. However, AE's approach ignores the energy value of combined cycle units which have substantial hours of use throughout the year. Energy is a principal consideration in choosing whether to install a combined cycle or combustion turbine.

proxy for the portion of plant cost which is energy-related. Based on the average weighted capacity factor for AE's intermediate units, 34% of Intermediate is allocated on energy and 66% is allocated on a 12 CP basis. The Peak capacity is allocated on the basis of the ERCOT 4 summer coincident peaks (4CP). The summer peaks provide higher prices which justify the operation of high variable cost generators. This reflects the role of quick start peak generation in meeting the primary peak demands. I developed two variations of BIP class allocation factors.

**Q. WHAT ARE THE TWO VERSIONS OF BIP THAT YOU PREPARED?**

A. Class allocation factors for both versions are shown on Schedule CJ-2. The "net plant" version (BIP-N) is based on net plant values for the generation. This reflects both depreciation and investment cost in "as spent dollars." The problem with this approach is that it may distort the relative value of Base, Intermediate, and Peak hours simply due to the timing of plant installation dates. For example, the South Texas Project and Fayette Power Plant were constructed many years ago, and much of the original investment has been paid off by customers already. If all plant costs are converted to the same year's dollars, the values for Base, Intermediate, and Peak generation can be compared on an economically equivalent basis. Therefore, I prepared a "replacement cost" version of BIP (BIP-R), which adjusts the Base, Intermediate, and Peak ratios to reflect the costs of generating technologies in 2014 dollars. This version utilizes the U.S. Department of Energy (DOE) generation cost estimates (installed capital cost per kW $2014) for current nuclear, coal, combined cycle, and combustion turbine technologies to develop Base, Intermediate, and Peak plant cost relationships. In my experience, the DOE generation cost estimates are used by electric utilities (including Austin Energy), regulatory commission, and regional transmission organizations as generic plant costs. The replacement cost version of BIP (BIP-R) also is shown on Schedule CJ-2.[40]

**Q. WHICH OF THE TWO VERSIONS OF BIP DO YOU RECOMMEND?**

A. My recommendation is to use BIP-R, and my class cost of service results incorporate BIP-R as the production demand allocation factor. In my opinion, plant cost comparisons based upon equivalent overnight dollars provide the most reasonable results.

**Q. HAVE YOU COMPARED THE RESULTS OF BIP-R TO ANY OTHER ENERGY WEIGHTED PRODUCTION DEMAND METHODOLOGIES?**

A. Yes. The NARUC CAM sets out a formulaic approach termed Average & Peak-12 CP (A&P-12 CP). This methodology classifies a portion of production plant equal to the applicable load factor as energy-related, and allocates the remainder using 12 CP. Under certain simplifying assumptions, this method is mathematically equivalent to a time of use capacity utilization method.[41] One of the simplifying assumptions of the proof is that costs do not vary by types of technology. In order to incorporate a more realistic assumption, I adjusted the load factor in A&P/12 CP to reflect the cost differential between installing a new combined cycle units instead of a combustion turbine.[42] AE's

[40] The allocation factors for BIP-R are nearly the same as using gross plant for the relative weighting of Base, Intermediate, and Peak.

[41] "Capacity Utilization Responsibility: An Alternative to Peak Responsibility," Dr. Michael Proctor, Public Utility Fortnightly at 31, April 26, 1983.

[42] Based on the DOE generation cost assessment, an advanced combustion turbine installation cost cost/kW is 33% less than an advanced combined cycle capital cost. Therefore, the load factor weighting for peak demand is reduced by that percentage, and the load factor weighting for average demand is adjusted accordingly so that the formula equals 100%. This results in a formula based on 80% energy and 20% 12 CP.

resource plan includes the addition of a new combined cycle plant, and the alternative to this type of unit is a combustion turbine peaker; therefore, the capital cost differential between combined cycle and peaker generation can be used to depict the lower capital cost of meeting peak. The resulting Adjusted A&P-12 CP produces class allocation factors almost the same as BIP-R, as shown on Schedule CJ-2. This confirms that a time of use based methodology will produce results approximately the same as BIP-R.

**Q. DOES AE'S CURRENT RESOURCE PLAN INCLUDE FUTURE NON-DISPATCHABLE RESOURCES WHICH WILL ENABLE THE UTILITY TO REDUCE PEAK DEMAND AT A LOWER COST THAN A GAS-FIRED COMBUSTION TURBINE?**

A. Yes. AE's current resource and climate protection plan includes large quantities of projected demand-side management measures which incur a levelized capital cost 36% less expensive per mWh than a combustion turbine.[43] Therefore, the peak component of BIP may reflect an upper limit on the cost of serving peak periods. Solar non-dispatchable resources may provide energy value at a levelized capital cost roughly equivalent to new coal and nuclear capacity.[44]

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[43] Slide presentation referenced in the Supplemental Response to ICA 4-7.

[44] *Ibidem*. Levelized capital cost per mWh assumptions used by Austin Energy: Photovoltaic solar $46 (West Texas) and $93 (local); coal $55 and nuclear $105.

### 4. BIP Consistency with ERCOT Market

**Q. GIVEN THAT AUSTIN ENERGY OPERATES IN THE ERCOT MARKET, PLEASE EXPLAIN WHY IT IS IMPORTANT THAT THE PRODUCTION DEMAND METHODOLOGY RECOGNIZES TYPES OF GENERATING PLANTS?**

A. Generators (including AE) submit real time pricing bids into the ERCOT market, and ERCOT dispatches generation on a five minute or less basis, utilizing the market clearing price for the demand level at that instant. Under ordinary conditions, generators will submit bids close to the generation unit's variable cost in order to ensure that the unit operates when it is economic to do so. As a result, generating unit's annual hours of operation will depend on its variable cost. And, as noted previously, higher capital cost plants tend to have lower variable cost, and vice versa. For generation planning purposes, the Price Duration Curve for ERCOT is more relevant to Austin Energy than the load characteristics of the individual utility.[45] The Price Duration Curve will provide information on the number of hours that each generation unit is likely to operate, thereby allowing the generators' management to estimate the probable net revenues produced by each plant. Thus, information regarding the ERCOT market is critical to AE's decisions to operate and make additions to its generation fleet.

[45] The price duration curve for an annual period in ERCOT will show the number of hours associated with each pricing interval in the ERCOT market. ERCOT's price duration curve is shown on Figure 3-4 at page 3-15 of AE's Tariff Package Proposal.

**Q. CAN YOU PROVIDE AN ILLUSTRATION BASED ON THE TYPES OF GENERATING UNITS OWNED BY AE?**

A. Yes. The table, below, is based on the price duration intervals in the 2014 ERCOT State of Market Report. The variable costs for nuclear and coal units are based on the independent market monitor's estimate, and the price of gas is assumed to be $4.90 per mmbtu. I have assumed an average heat rate of 9,000 for combined cycle and conventional steam units and 10,500 for conventional combustion turbines, plus $2.00 per mWh for gas plant variable O&M. These assumptions and results are for illustrative purposes only. As shown in the table, only coal and nuclear plants are positioned to operate during most of the hours within the 0 - $50 per mWh interval. Conventional steam and combined cycle units are positioned near the upper limit of the $50 price interval and are likely to operate only during a relatively small slice of hours for that interval. Combustion turbines have a variable cost above the $50 price interval, and therefore can operate in less than 8% of annual hours.[46] The highest capital cost plants can operate in most of the lowest price interval, which includes 91% of hours. The second highest capital cost units, intermediate, can operate for a number of hours midway between the peak and baseload plants.

[46] 693/8,760=8%. Note that total hours in table do not equal 8,760 because the table excludes price intervals below $0.

**ERCOT Market Price Intervals and Hourly Frequency**

| *Price Interval ($/mWh)* | *Hours* | *Variable Cost* |
|---|---|---|
| **0 - $50** | **7936** | |
| Nuclear | | $ 8.00 |
| Coal | | $ 24.00 |
| **Over $50** | **693** | |
| Conventional CC & Steam Gas | | $ 46.10 |
| Combustion Turbine | | $ 53.45 |

*(Avg. ERCOT North and South Zones, 2014)*

**Q. HOW DO HOURS OF OPERATION RELATE TO THE DECISION TO INSTALL GENERATION?**

A. Both the likely frequency of hourly operation, as well as prices in those hours, will determine the revenues produced by each type of generation plant. The ERCOT Independent Market Monitor performs a "Net Revenue" analysis for different generator technologies, based on hourly prices net of variable cost. For generators contemplating the installation of new plants, the net revenues can be compared to the annual capital cost for the new plant in order to estimate profit. The market monitor's Net Revenue estimates for 2014 can be arranged into a Base-Intermediate-Peak format, as shown below.

**Net Revenues: 2014 ERCOT Market Report**[47]

| | |
|---|---|
| Baseload | $105 - $227 kW-yr. |
| Intermediate | $57 kW-yr. |
| Peak | $37 kW-yr. |

**Q. TAKING INTO ACCOUNT THE OPERATION OF THE ERCOT MARKET, SHOULD AUSTIN ENERGY ENCOURAGE ITS CUSTOMERS TO USE ELECTRICITY DURING THE LOW PRICE HOURS OF THE PRICE DURATION CURVE?**

A. Not necessarily. This highlights a distorted assumption underlying peak responsibility production demand methods. Narrow peak responsibility allocation methods imply that base-related costs associated with off-peak usage should be considered "free." But this ignores the opportunity cost of selling Austin's baseload generation in the market. Encouraging off-peak usage indirectly decreases the net revenues which can be produced by baseload generation.[48] Peak responsibility methods assume that generation plant in excess of off-peak load is idle. This is certainly not the case for Austin Energy's baseload plants, which will operate in as many hours as possible, regardless of its customers' off-peak usage.

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[47] 2014 ERCOT State of the Market Report at page xvii.

[48] As a load serving entity, Austin Energy must purchase power for its customer's off-peak usage at the market clearing price. If AE has baseload capacity available in excess of its own off-peak loads, AE can generate excess power at that same market price, thereby producing "profits" to offset utility costs paid by its customers.

**Q. PLEASE SUMMARIZE YOUR POSITION?**

A. Production demand allocation methods like my recommended BIP methodology are consistent with the capital-energy trade-offs associated with generation entry into the ERCOT market.

### C. Production Non-Fuel O&M Expense Classification

**Q. DO YOU AGREE WITH AE'S CLASSIFICATION OF PRODUCTION NON-FUEL O&M ACCOUNTS?**

A. No. AE classified all production non-fuel O&M expense as demand-related. The customary approach is to split these expenses between demand and energy. Although I sometimes disagree with the demand/energy split for generation O&M applied by other utilities, I cannot recall another bundled electric utility which owned multiple generating units that applied a 100% demand classification to the expenses. Among current bundled electric utilities in Texas, SWEPCO, SPS, and El Paso Electric Co. classify a portion of production non-fuel O&M expense as energy-related. The AE cost of service model includes a workpaper (WP F-2.4) entitled "develop production allocators for cost accounting method" which divides the production non-fuel O&M expenses between energy and demand, but AE chose not to use this classification in the cost of service study presented in support of its proposed tariffs.

**Q. HOW DO YOU PROPOSE TO CORRECT THE CLASSIFICATION OF PRODUCTION NON-FUEL O&M EXPENSE?**

A. The most reasonable approach is to utilize the classification recommended in the NARUC CAM. This method represents an accepted convention, and has been adopted by the Texas PUC in the past. Based upon my review, AE's unused "cost accounting method" appears to be consistent with the NARUC CAM.

**Q. PLEASE DESCRIBE THE NARUC COST ALLOCATION MANUAL'S METHOD FOR CLASSIFYING PRODUCTION NON-FUEL EXPENSE.**

A. Some accounts are classified entirely as either energy or demand. However, most accounts are split between energy and demand in proportion to the labor and commodity costs in the account. For these accounts, labor costs are considered more fixed in nature, and are classified as demand-related, while commodities are considered more variable in nature, and are classified as energy-related. This approach is commonly referred to as a cost accounting method; from a cost accounting perspective, labor costs are fixed over a short run period and materials and supplies tend to be consumable or disposable. The AE cost of service workpaper referenced above, WP/F-2.4, is based on the same labor proration method. Therefore, I recommend modifying the cost of service study to apply the classification designated by AE as the cost accounting method.

**Q. WHY IS A SUBSTANTIAL PORTION OF GENERATION MAINTENANCE EXPENSE ENERGY-RELATED?**

A. Like most mechanical devices, the frequency of maintenance for production facilities is generally a function of the wear and tear associated with the duration of operating the facilities. It is not reasonable to assign causal responsibility for maintenance costs solely to peak hours during the year.

**Q. IS SOME PORTION OF PRODUCTION OPERATION EXPENSE PROPERLY CLASSIFIED AS ENERGY-RELATED?**

A. Yes. Certain expenses such as coolants, lubricants, nuclear fuel moderation fluids, and other consumable supplies vary with the annual generation of the production facilities. Moreover, baseload facility operating expenses obviously are needed to support operations throughout the year.

**Q. HOW DOES THE CLASSIFICATION AFFECT CUSTOMER CLASS ALLOCATION?**

A. Demand classified accounts are allocated on the basis of the production demand allocator. Energy classified accounts are allocated on the basis of class energy use.

### D. Functionalization/Classification of A& G Account 920 (Salaries)

**Q. WHAT IS ADMINISTRATIVE & GENERAL (A&G) ACCOUNT 920?**

A. As a matter of accounting definition, this account contains salaries and wages which cannot be attributed to any particular function of the utility. Examples of typical expenses include the chief executive officer, general corporate officers, the treasury and finance departments, the human resources department, corporate strategic planning, shareholder services, etc. These are common costs of the utility which are only weakly associated with any particular class allocation factors.

**Q. HOW DOES AE FUNCTIONALIZE ACCOUNT 920?**

A. Functionalization is process of assigning the costs to production, transmission, distribution, and customer functions. The Company allocates the expense in proportion to labor costs within each functional category (Labor excluding A&G). This is not unusual; many utilities classify this account to labor. Note that each functional group (such as production O&M) includes the supervisors and management for the group's work force within the functional labor expense. Thus, A920 management salaries are not directly involved in supervising the workers included in labor excluding A&G. Typically, Account 920 personnel are responsible for a broad scope of management activity, not just supervising the utility's employees. In this particular case, my recommendation is to modify the functionalization allocator for A920.

**Q. WHAT IS THE PROPER CRITERION FOR SELECTING AN APPROPRIATE ALLOCATOR FOR A920?**

A. Because none of the potential allocators are strongly related in a causal sense to A920, the selection should focus on the extent that the allocator spreads A920 salaries and wages broadly and equitably across utility functions. Austin Energy's top management is responsible for aspects of the utility's operations, and it makes sense that their salary costs are recovered broadly across functions.

**Q. WHY DO YOU PROPOSE TO CHANGE THE USE OF A LABOR[49] ALLOCATION FOR THIS ACCOUNT?**

A. Because AE is a non-managing partner in the South Texas Project and Fayette Coal Plant, AE's class cost of service study does not include labor personnel at those plants within the labor allocation factors (except for relatively minor salary expense associated with AE personnel who oversee the plants). Although these two plants constitute approximately 55% of non-fuel production expense, the plants' labor expense is not

[49] The functionalization allocator is designate PayrollxAG.

included in the labor allocator. As a result, the labor allocation will understate the magnitude of the production function. For this reason, an exception to the typical practice of using a labor allocation for A920 is justified.

**Q. WHAT DO YOU PROPOSE AS THE ALLOCATION METHOD FOR A920?**

A. My recommendation is to allocate A920 on the basis of non-fuel O&M expense, excluding A&G.[50] As illustrated in the comparison below, this method spreads the A920 expenses more broadly across functions than the labor allocation. The O&M allocator assigns a similar percentage of cost to Production as the Gross Plant allocator. The labor allocator, by comparison, understates the allocation of cost to Production. This confirms my inference, above, that the exclusions of FPP and STP labor costs from the labor allocator biases the Production results downward.

**Functional Percentages**

| | **Labor** | **Plant** | **NF O&M** |
|---|---|---|---|
| **Production** | 21% | 47% | 46% |
| **Transmission** | 9% | 12% | 24% |
| **Distribution** | 36% | 40% | 12% |
| **Customer** | 34% | .1% | 18% |
| **Total** | 100% | 100% | 100% |

**Q. IS YOUR RECOMMENDATION AFFECTED BY THE FACT THAT THE COST OF SERVICE STUDY DIRECTLY ASSIGNED SOME A&G EXPENSES TO PRODUCTION?**

A. No. The cost of service study *should* directly assign any common costs which can be identified as pertaining to a particular function. This is a step that is taken before

[50] This allocator is designated O&MxAG in the cost of service study.

allocating common costs. But the existence of direct assignment does not affect the choice of allocation methods for the remaining common costs. If the $3.2 million of A920 direct assignment is included with the labor allocation, the production ratio increases to 28%. Yet, this is still 19 – 20 percentage points below the production allocation percent for O&M and Plant methods.

**Q. WHY IS IT IMPORTANT TO ALLOCATE THESE COMMON COSTS IN REASONABLE PROPORTIONS ACROSS FUNCTIONS?**

A. The customer classes utilize functions in different proportions. Virtually all classes are served by the production function. However, transmission voltage customers are not served by the distribution function. The vast majority of customer functions are assigned to the residential class. Therefore, an allocation of A920 which is not proportionate to the resources devoted to each function will produce biased results for particular customer classes.

**Q. IS AN O&M ALLOCATOR REASONABLY RELATED TO THE RESPONSIBILITIES OF MANAGEMENT ASSOCIATED WITH ACCOUNT 920?**

A. Yes. Presumably the top management of the Company pay attention to overall expense levels, whether associated with labor or procurement of materials. In addition, the O&M allocation will reflect contract labor expense, as well as employee wages. Austin Energy's management should be no less concerned about the level of contract labor cost than they are about employee expense.

**Q. SHOULD THIS ALLOCATOR CHANGE BE CARRIED THROUGH TO THE PROCESS OF SUB-FUNCTIONALIZATION?**

A. Yes. The A&G expense assigned to each function is classified to sub-functions based on the function's labor expense. The sub-functionalization that produces the most significant effect on classes arises within the distribution function, because sub-functionalization spreads costs to voltage levels. For the same reason that the A920 functionalization method should be changed from labor to non-fuel O&M, my recommendation is that distribution function A920 costs should be sub-functionalized on the basis of distribution O&M expense, instead of distribution payroll expense.

**E. Classification and Allocation of Transformer/Substation Investment**

**Q. DO YOU DISAGREE WITH AE'S CLASSIFICATION AND ALLOCATION OF TRANSFORMER INVESTMENT?**

A. Yes. The Company classifies transformer costs as 100% demand-related. Line transformers and related devices (such as capacitors and voltage regulators) are recorded in A368, which AE allocates on a 12NCP basis to secondary classes. Transformers and related devices installed in distribution substations are recorded in A362, Station Equipment, which AE allocates on a 12NCP basis to both secondary and primary classes. 12NCP reflects the average of each class' monthly peak demand. My recommendation is to allocate A362 and A368 costs on the basis of class summer energy use. Energy use recognizes the role of transformers and substations in producing energy losses. Limiting the energy use to summer months recognizes the effect of high demand periods and higher ambient temperatures on transformer capacity. This allocation is similar to Center

Point Electric's use of summer kWh to assign transformer investment to customer classes. I will discuss transformers and substations in more detail below.

**Q. PLEASE DISCUSS HOW TRANSFORMER INVESTMENT IS RELATED TO ENERGY LOSSES.**

A. The cost-effectiveness of selecting particular transformers is influenced by the trade-off between up-front investment costs to achieve higher energy efficiency and the long term reduction in energy costs due to fewer losses. For many years, electric utilities considered energy cost reduction trade-offs in transformer procurement. However, five years ago, the Department of Energy ("DOE") implemented significantly higher energy efficiency performance standards for utility transformers.[51] Although the influence of energy on transformer investment has always existed, recent federal changes have provided a more apparent illustration of the effect. Based on my review of this issue in various electric utility cases, the higher investment cost of meeting the transformer energy efficiency standard appears to be in the range of 10% - 24%.[52] Austin Energy estimates a 9% increase in network vault transformers due to DOE 2016 energy efficiency standards.[53] With respect to previous DOE transformer standards, AE preempted the cost impact by installing transformers which met the new standards before

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[51] 10 CFR 431.191, *et. seq*.

[52] For example, the transformer price increases to meet the efficiency standard is 18% for Center Point Electric Delivery and 24% for Connecticut Light & Power Co.

[53] AE Response to ICA Request 1-6.

the regulations went into effect.[54] Transformer procurement costs affect energy loss levels, which in turn affect AE's fuel and purchased power costs.

**Q. CAN YOU EXPLAIN HOW TRANSFORMERS ARE RELATED TO ENERGY LOSSES?**

A. Transformers are one of the largest sources of energy losses on the electric delivery system. These losses result in higher fuel cost to supply end use customers, particularly secondary customers.

Transformer energy losses are categorized as either core losses, which occur 8,760 hours per year, as long as the transformer is connected to the system; or load losses (sometimes called winding losses), which vary with the amount of power flowing through the transformer. Both forms of loss can be reduced through the purchase of transformers that are designed to achieve greater efficiency. However, the increased efficiency of the transformer generally results in higher installed investment cost. DOE performed cost-effectiveness analyses of lifetime costs (transformer installation cost) and benefits (energy savings) in order to determine federal efficiency standards for utility transformers. The net present value savings in fuel costs from more efficient transformers is very significant.

[54] *Ibidem.*

**Q. ARE CAPACITORS AND RELATED DEVICES IN ACCOUNT 368 USED TO REDUCE ENERGY LOSSES?**

A. Yes. Properly applied capacitors "return their investment very quickly" by saving "significant sums of money in reduced losses."[55]

**Q. WHAT ARE THE IMPLICATIONS FOR COST ALLOCATION?**

A. Investment costs for transformers have been, and will be, incurred to reduce customers' variable energy expenses, and the benefits of such investment should reflect class energy use on a kWh basis. Furthermore, distribution substations convert transmission voltage to distribution voltage, and therefore also are a source of energy losses. Station equipment in A362 consists of transformers, capacitors, and similar devices which should be allocated on a comparable basis to A368, except that the allocation applies to primary voltage customers as well as secondary customers.

**Q. IS YOUR USE OF A KWH ALLOCATOR CONSISTENT WITH A STUDY COMMISSIONED BY NARUC REGARDING COST ALLOCATION FOR UNBUNDLED DISTRIBUTION COSTS?**

A. Yes. The Regulatory Assistance Project ("RAP") published a report for NARUC on the implications of unbundling for distribution rate design.[56] The report recommended that a portion of distribution costs be allocated on an energy basis, for both embedded and marginal cost of service studies:[57]

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[55] Electric Power Distribution Equipment and Systems at 273, T.A. Short, EPRI Solutions, Inc.

[56] Weston, Harrington, Moskovitz, Shirley, And Cowart, Charging For Distribution Utility Service: Issues In Rate Design, (Dec. 2000).

[57] *Id.* at 32, 39 [references omitted].

> [Embedded Cost of Service Study:]
>
> A similar kind of analysis can inform the design of distribution systems, as it also does transmission. The question is whether there is some amount of capacity in excess of the minimum needed to meet peak demand that can cost-effectively be installed. The additional capacity — larger substations, conductors, transformers — will reduce energy losses; if the cost of energy saved is greater than that of the additional capacity, then the investment will be cost-effective and should be made. For the purposes of cost analysis and rate design, these kinds of distribution investments are rightly treated as energy-related.
>
> [Marginal Cost Study:]
>
> As discussed earlier, to the extent that distribution investments are made to offset energy needs, there are necessarily costs associated with avoiding those investments. Losses, heat build-up, frequency of overloads, etc., are aspects of energy use that affect distribution investment and operations; thus there are marginal energy costs in distribution.

According to the RAP report, distribution investments that are incurred to reduce energy expense are appropriately allocated on an energy basis. My recommendation is consistent with this conclusion.

**Q. DO ANY TEXAS UTILITIES UTILIZE CLASS KWH USAGE TO DEVELOP THE ALLOCATORS FOR TRANSFORMERS?**

A. Yes. Center Point Electric uses class summer kWh consumption to develop its allocation. In Docket No. 38339, the Commission reversed the Proposal for Decision's acceptance of my proposal to classify a portion of transformer investment on overall class energy use, citing evidence that Center Point's allocation process already uses energy usage to allocate transformers.[58] My recommendation in this case is consistent with that process, recognizing both energy use and the higher demand summer season.

### F. Allocation of Customer Service

**Q. HOW DOES AE'S COST OF SERVICE STUDY ALLOCATE UNCOLLECTIBLE EXPENSE AMONG CUSTOMER CLASSES?**

A. AE directly assigns uncollectible expense based upon bad debt experience during 2014 for each customer class.

**Q. DO YOU AGREE WITH DIRECT ASSIGNMENT OF UNCOLLECTIBLE EXPENSE?**

A. No. A more reasonable method is to allocate uncollectible expense in proportion to a revenue requirement allocation factor, sometimes called a "revenue allocation." I agree with the order of the Texas Public Utility Commission on this issue in Entergy Docket No 16705. The order in Docket No. 16705 succinctly explained the reasoning for rejecting the direct assignment proposed by Entergy, in favor of a revenue allocation:

[58] *Application of Center Point Electric Delivery for Rate Increase*, Docket No. 38339, Order on Rehearing at 10: "CenterPoint's rate design expert testified that CenterPoint has already assigned non-minimum plant transformer investment based on a study utilizing energy usage by the rate classes using the transformers. The Commission finds that CenterPoint's proposal appropriately assigns these costs."

> Just as it may seem unfair to have the industrial customers absorb the bad debts of a few individuals, it is just as unfair to have the great majority of dutiful residential ratepayers pay those debts. The passing on of such costs to others is generally factored into the cost of doing business. It is a cost that is better absorbed by the many. Therefore, uncollectible expense should be allocated at both the jurisdictional and class levels on the basis of jurisdictional and class operating revenues.[59]

As recognized in the finding of fact quoted above, the Texas PUC has treated uncollectibles as a social cost that must be absorbed on an equitable basis across classes, because the cost causers are no longer on the system. Direct assignment of the cost does not allocate the expense to cost causers, because the non-payers, by definition, are not paying customers.

**Q. IS THE ENTERGY DECISION CITED ABOVE CONSISTENT WITH TEXAS PUC PRECEDENT FOR INTEGRATED ELECTRIC UTILITIES?**

A. Yes. Based upon my experience, the Texas Commission's use of a revenue allocation for uncollectible is one of the most consistent allocation practices approved or ordered by the Commission over the past 25 years.[60] The PUC Staff was the principal advocate of this practice during most of that period. Although the nature of uncollectible expense is somewhat different in a retail competition environment, most unbundled TDUs in Texas

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[59] *Application of Entergy Gulf States, Inc. for Approval of its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Underrecovered Fuel Costs*, Docket No. 16705, Second Order on Rehearing at Finding of Fact No. 231 (Oct. 14, 1998).

[60] For example, *see Application of El Paso Electric Company for Authority to Change Rates*, Docket No. 9945, 18 P.U.C. BULL. 9 (Feb. 1992); *Application of Houston Lighting & Power Company for Authority to Change Rates*, Docket No. 6765, 13 P.U.C. BULL. 1 (Nov. 1986); *Application of Gulf States Utilities Company for Authority to Change Rates*, Docket No. 7195, 14 P.U.C. BULL. 1943, 2425 (1989) (May 1988); *Application of Texas Utilities Electric Company for Authority to Change Rates*, Docket No. 11735, Order on Rehearing, Finding of Fact No. 162 (Apr. 20, 1994).

allocate uncollectible expense on a revenue basis. The Texas PUC confirmed the precedent this year. Although both the PUC Staff witness and an industrial witness recommended direct assignment in the Southwestern Public Service Co. case, the pending order in that case adopts a revenue allocation, based on the following findings:

> SPS reasonably allocated Uncollectible Account expense in FERC Account 904 on the basis of present base rate sales by class.
>
> Uncollectible expenses are caused by non-paying customers, and the current customers in a particular class are not the cause of uncollectible expense created by other members of that class.[61]

**Q. IS DIRECT ASSIGNMENT ADEQUATE TO REFLECT THE COMPANY'S EXPOSURE ON A CLASS BASIS?**

A. Probably not. If one accepts the direct assignment concept, the class allocations should reflect the future risk exposure posed by each customer class. The direct assignments tend to be based on experience over a relatively short period of time. The magnitude of the uncollectible expense in a given period is affected not only by the frequency of customer accounts which are written off during a period, but also by the amount of revenue billing attributable to each particular type of customer. For example, the bad debt risk for a class with a small number of customers of varying sizes may not be adequately measured over a short duration period. In addition, the *potential* for significant impact from individual large accounts should be considered. For instance, if an industrial or large business customer goes out of business due to bankruptcy, that individual default would result in a disproportionate increase in the amount of

[61] *Application of Southwestern Public Service Co. for Authority to Change Rates*, Docket No. 43695, Order, FOF 310 and 311.

uncollectible expense. This event is likely a low probability/high consequence exposure. Although the event may not occur in the specific one, or two year period, the allocation of an uncollectible allowance should reflect the broader exposure if a very large customer defaults. For example, although no transmission voltage customers were assigned uncollectible expense based on 2014 experience, at least one transmission voltage customer has filed bankruptcy since 2012.[62] The cost of service study assigned no uncollectible cost to Secondary >300 kW (due to lack of information).[63] AE is aware of 27 bankruptcies since 2012 in the Secondary >50 kW category, but is unable to determine whether any of the bankruptcies involved customers greater than 300 kW.[64] The more reasonable solution is to allocate uncollectible expense as a cost of doing business which should be spread proportionately to all customer classes.

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.**

A. AE's proposed direct assignment of uncollectible expense should be rejected. Instead, uncollectibles should be allocated on the basis of revenues (Rev Req allocation).

### G. Allocation of Meters and Services

**Q. HOW ARE METERS ALLOCATED IN THE AE CCOS STUDY?**

A. AE develops a weighted customer allocation which reflects the cost of different meter sizes installed by customer class. This method is appropriate and standard, as far as it

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[62] AE Response to ICA 2-29.

[63] Inadequate secondary >50 kW uncollectible records constitute another flaw in AE's direct assignment. The records did not permit identification of uncollectible based on the proposed Secondary class configuration. As a result, AE subjectively chose to assign all of the Sec >50 kW uncollectible expense to <300 kW customers, assuming that the cost belonged to the class with the most customers.

[64] Ibidem.

pertains to the traditional meter function. However, AE has been aggressive in the sophistication of the meters it deploys, and the implication of these advancements is that substantial meter investment cost has been expended to access meter functions which transcend the standard billing and collection measurement role. The allocation method for meter investment should take into account the incremental cost of enabling other functions.

**Q. WHAT IS THE INCREMENTAL COST OF INSTALLING SMART METERS OVER ELECTRO-MECHANICAL METERS?**

A. The cost of a manual residential meter is $48 and the cost of a comparable smart meter is $190. Thus, the manual meter is approximately 20% of the cost of the smart meter. The remaining 80% of the smart meter cost represents investment incurred for functions which cannot be performed by a manual meter.

**Q. WHAT ADDITIONAL FUNCTIONS CAN BE ACCESSED AS A RESULT OF THE INCREMENTAL INVESTMENT FOR SMART METERS?**

A. A significant benefit arises from reductions in meter reading cost. Additional utility benefits involve the reliability function, enabling improved outage detection and system wide recovery.[65] Societal benefits arise from direct load control, demand response, and integration of distributed generation, which reduces peak demand, thereby applying downward pressure on energy prices in spot markets and reducing the need for new

[65] Costs and Benefits of Smart Meters for Residential Customers, July 2011, Edison Foundation Institute for Energy Efficiency, White Paper at 5.http://www.edisonfoundation.net/iei/Documents/IEE_BenefitsofSmartMeters_Final.pdf.

generation.[66] Customers benefits arise from enhanced ability to manage energy costs, shift loads, and identify wasteful uses of electricity.[67] AE recognizes most of these functions and continues to activate meter functions which enable these benefits.[68]

**Q. HOW DID YOU RELATE THESE INCREMENTAL COSTS AND FUNCTIONS TO THE CLASS ALLOCATOR?**

A. The avoidance of meter reading expense constitutes as much as one-half of the net present value benefit of smart meter investment,[69] and this proportion of the incremental cost can be allocated on the weighted customer basis. However, the remainder of the incremental cost pertains to demand-side management, avoided generation cost, and reliability. Production demand is a reasonable measure for these functions. Therefore, my recommendation is to allocate meter investment on a 60% weighted customer and 40% production demand basis.[70]

**Q. HOW DID AE'S CCOS STUDY CLASSIFY SERVICES?**

A. The Company classified the service drops as demand-related distribution. The NARUC CAM specifies that services are properly classified as customer-related. In my experience, other electric utilities treat services as customer-related. My recommendation is to change the classification of services to customer.

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[66] Id.

[67] Id.

[68] AE Response to AELIC Request 9-23 and 9-24.

[69] Costs and Benefits of Smart Meters for Residential Customers, page 31 – 34.

[70] The incremental investment above manual meter cost is 80% of the total meter plant. 40% of the total meter plant cost (80% X 50%) is allocated on a production demand basis.

**Q. WHAT IS THE EFFECT OF CHANGING THE CLASSIFICATION OF SERVICES?**

A. In AE's particular circumstances, classifying services as customer-related reduces the costs assigned to the customer function. This is because the total net services cost is negative.

## H. Allocation of Customer Accounts

### 1. Meter Reading

**Q. HOW DO YOU PROPOSE TO CHANGE THE CCOS STUDY'S ALLOCATION OF METER READING EXPENSE?**

A. AE allocates meter reading expense on the basis of number of customers. My recommendation is to allocate meter reading expense on the weighted customer allocator applied to meters. Meter reading expense obviously is associated with meter investment. The weighted customer allocator reflects differences in the costs of meters among the customer classes. Larger meters tend to be associated with larger customer bills, and the utility should take greater care in verifying the accuracy of higher revenue accounts. If a problem arises in the automated reading of large customer's bill, additional time is incurred by meter readers to re-set the demand meter when they manually re-read the meter.

### 2. 311 Expense

**Q. PLEASE DISCUSS AE'S 311 CALL EXPENSE.**

A. The 311 call center enables Austin residents to make inquiries or notifications to city departments. Austin Energy includes $2.38 million for this expense in A417 (General

Expense-Non Utility Operations), and functionalizes the expense to Customer. A relatively small portion of the expense is based on usage (number of call attributable to AE). Most of this expense is directly assigned to AE and supports the disaster recovery center. AE justifies the expenditure because it provides back up to AE's normal operations. This Center enables Austin Energy to operate in emergency mode due to severe storms or disaster conditions.

**Q. DO YOU AGREE WITH THE CCOS STUDY'S TREATMENT OF THIS EXPENSE?**

A. No. The primary function pertains to system reliability and maintaining continuous delivery of power. Disaster recovery presumably is focused on repairing and restoring power service. The expense is more reasonably functionalized to Distribution, because distribution facilities are most related to maintaining power delivery. Therefore, my recommendation is functionalize A417 to Distribution and to allocate the expense to classes based on distribution O&M expense.

### 3. Customer Service Accounts

**Q. HAVE YOU PROPOSED CHANGES TO THE ALLOCATION OF ANY CUSTOMER SERVICE ACCOUNTS?**

A. Yes. I have modified the allocations of the following accounts: 908 – 910 (Customer Assistance, Informational Advertising, Miscellaneous Informational Expense, Advertising Expense, and Miscellaneous Sales Expense). Except for the portion of this expense allocated to Key Account customers, AE allocates these accounts based on number of customers by class.

**Q. WHAT IS INCLUDED IN THESE ACCOUNTS?**

A. The object of these accounts is to advise customers on the safe and efficient use of electricity, promote or retain electrical usage, or encourage conservation or environmentally beneficial activities. These costs include exhibitions, displays, and advertising designed to promote utility service. The activities can be designed to market the utility's services, promote the image of the utility, retain customers, and/or foster the safe use of the utility's services and facilities.

**Q. ARE THESE EXPENDITURES PROPERTY ALLOCATED ON AN UNWEIGHTED CUSTOMER BASIS?**

A. No. There is no reason to believe that the costs of achieving such general objectives will vary in proportion to the number of customers. The expenditures represent a general cost of doing business and are more property treated as an overhead. In addition, customer assistance and information costs are incurred to direct customers to energy efficiency programs, and such programs are not otherwise allocated on a customer basis. The NARUC CAM encourages weighting of customer allocations for these accounts. For A906 – 910, the manual recommends separate analysis of actions which affect customers' usage of generation and energy. For A911 – 917, the manual states:

> Allocation of these costs, however, should be based upon some general allocation scheme, not numbers of customers. Although these costs are incurred to influence the usage decisions of customers, they cannot property be said to vary with the number of customers. These costs should be either directly assigned to each

customer class when data are available, or allocated based upon the overall revenue responsibility of each class.[71]

**Q. WHAT IS YOUR RECOMMENDATION FOR THE ALLOCATION OF THESE ACCOUNTS?**

A. Austin Energy directly assigns 14% of these accounts to Key Account customers. My recommendation accepts the direct assignment of this portion of the accounts. However, I have developed a weighted customer allocator, instead of unweighted customers, for the remainder of the accounts. The weighted allocator for the remaining 86% of the expense is 50% class revenue requirement and 50% number of customers. This approach recognizes that the general expenses in these accounts which cannot be directly assigned should be treated, in part, as general overhead. This weighting also includes the same revenue requirement allocation applied to energy efficiency programs, thereby recognizing that some customer assistance and informational activities direct consumers to energy efficiency programs.

**I. Functionalization of Service Initiation Revenue**

**Q. WHAT IS AE'S FUNCTIONALIZATION OF THE NEW SERVICE INITIATION FEE?**

A. The new service connection fee pertains to starting new service and reconnecting a customer who has been disconnected. AE classifies the fee as distribution-related because "the service is associated with the distribution of power to the customer." However, contrary to the implication of such a rationale, the fee does not recover the

[71] NARUC CAM at 104.

incremental facility costs of new services and new meters.[72] This fee is for ordering the initiation of new service.

**Q. DO YOU AGREE WITH AE'S FUNCTIONALIZATION OF THIS REVENUE ITEM?**

A. No. The revenues are more reasonably identified as customer-related. Service initiation pertains to customer access, and customer access is part of the customer function. Service initiation frequency is more likely to vary with number of customers than distribution demands.

### J. Summary of Results

**Q. DO YOUR PROPOSED CHANGES TO THE CCOS STUDY SIGNIFICANTLY ALTER THE INTERCLASS RELATIONSHIPS BETWEEN RESIDENTIAL AND SMALL COMMERCIAL CLASSES AND THE OTHER CUSTOMER CLASSES?**

A. Yes. Austin Energy claims that the residential and Sec.<10 kW classes currently receive significant subsidies from other classes. As a result, AE proposes that the residential and small commercial classes should not be assigned any of the $17 million base revenue reduction. In addition, AE suggests that the two classes should transition in the direction of cost in future rate requests. However, without any of the revenue requirement reductions proposed in Sec. III, but including my CCOS changes proposed in this section, the current revenues (including test year PSA and pass-through charges) for residential and small commercial slightly exceed the class cost of service. This casts considerable doubt on AE's claim that a subsidy to the residential and small commercial class is

[72] AE Response to ICA Request 7-3.

embedded in current rates. This is shown below. Schedule CJ-3 shows the comparable results for all classes.

| | Above/(Below) Cost (thousands) | |
|---|---|---|
| | Resident. | Sec.<10 kW |
| **ICA Position** | $11.409 | $687.4 |
| **Indicated Incr./(Decr.)** | -4.40% | -3.60% |
| | | |
| **Sch. G10 As Filed** | ($53,411) | ($783.) |
| **Indicated Incr./(Decr.)** | 20.80% | 4.10% |

**Q. WHAT ARE THE BASE REVENUE RESULTS USING BOTH ICA'S REVENUE REQUIREMENT RECOMMENDATION AND CCOS ALLOCATION?**

A. At current base revenues, both the residential and Sec. <10 kW classes are fully above cost and deserving of base revenue reductions. The results for the two classes are shown below. Schedule CJ-4 shows the comparable results for all classes.

| | ICA CCOS Study Above/(Below) Cost | |
|---|---|---|
| | **Residential** | **Sec.<10 kW** |
| **ICA Position** | $ 11,409,407 | $ 687,049 |
| **Indicated Incr./(Decr.)** | -4.40% | -3.60% |
| | | |
| **Sch. G10 As Filed** | $ (53,411,041) | $ (783,742) |
| **Indicated Incr./(Decr.)** | 20.80% | 4.10% |

**Q. HAVE YOU INCLUDED INFORMATION ON THE SPREADSHEET REFERENCES FOR THE MODIFICATIONS YOU MADE TO THE AE CCOS MODEL?**

A. Yes. Schedule CJ-5 provides the lines, columns, and tab labels for the changes that were made, pursuant to the rules for filing the recommendation.

## V. ALLOCATION OF REVENUE REDUCTIONS TO CLASSES

**Q. WHAT IS THE CLASS REVENUE DISTRIBUTION ISSUE IN THIS CASE?**

A. Class revenue distribution involves the assignment or allocation of a system revenue increase or decrease to rate classes. The CCOS results provide useful information which is considered in addition to non-cost principles. This case pertains to the allocation of a system revenue decrease. Based on ICA's revenue requirement adjustments, ICA proposes to allocate $39.8 million of base revenue decreases among customer classes.

**Q. WHAT IS THE APPROPRIATE ROLE OF THE EMBEDDED CCOS STUDY RESULTS IN DETERMINING CLASS REVENUE INCREASES?**

A. The CCOS provides useful information for developing the class revenue increases, but it should not be the sole consideration. Non-cost considerations are appropriate in mitigating pure CCOS results. This principle has been recognized in longstanding regulatory texts, such as Dr. James Bonbright's seminal *Principles of Public Utility Rates*.[73]

CCOS studies are imprecise instruments. The studies will allocate costs to a multiple decimal point level, but this may provide a false sense of security about the

[73] Bonbright, *Principles of Public Utility Rates* at 29, (Columbia Press 1961).

accuracy of the studies. This conclusion is based on two general reservations regarding embedded CCOS studies. First, some of the costs are classified and allocated on a disputable causal basis and subjective judgment enters into the selection and development of allocation methods. The CCOS results may be quite sensitive to alternative classification or allocation decisions which are within the range of reasonable choices. As a result, it may be more appropriate to characterize the CCOS in the form of a range of acceptable rates of return instead of a single point estimate. For instance, in the 2012 rate review, AE took the position that class revenue changes within 5% of the CCOS study result are reasonable and justified. Second, CCOS studies are a static snapshot of the dynamic relationship between supply and demand. Both costs and class usage characteristics will change over various time periods. For these reasons, some degree of judgment may be appropriate in applying the CCOS study to class revenue increases. "Cost based rates" are best viewed as representing a reasonable band around the CCOS results, rather than exact price points. Furthermore, CCOS studies which do not recognize the differences in risk associated with customer classes should be utilized cautiously.

**Q. PLEASE DISCUSS AE'S REVENUE DECREASE PROPOSAL.**

A. AE proposes an approximate $17 million base revenue reduction. Based on the CCOS results, AE proposes assigning no revenue decrease to the Residential and Sec. <10 kW and allocates the remainder of the decrease to commercial classes which are above cost. ICA disagrees with this proposal in two respects. First, the total revenue reduction should be approximately $39 million. Second, the CCOS study allocation adjustments presented in Sec. IV produce markedly different results regarding the relative cost positions of classes. The ICA CCOS results do not support AE's proposal to assign no revenue decrease to the Residential and Sec. <10 kW classes. The current base revenues for those two classes exceed the classes' cost of service.

**Q. WHAT GENERAL APPROACH GUIDED ICA'S CLASS REVENUE REDUCTION ALLOCATION?**

A. ICA contends that the revenue decrease should be distributed broadly among the customer classes, rather than precisely linked to specific CCOS results. AE is publicly owned, and excess revenues should be broadly shared among different types of customers. I used the CCOS study to determine the customer classes which are far below cost—in this case, the lighting classes. For those classes, my proposal leaves the base revenues unchanged. In addition, I used the CCOS study result to assign a base revenue increase to Transmission >20 MW, 85% LF. AE's rate filing explains that this class' revenues are designed to be set at cost. The customer in this class pays a fixed contract and will be unaffected. But setting the revenues at cost ensures that other customers are not subsidizing the contract rate. Incorporating an approximate $2 million base revenue increase for this class produces a $41.8 million revenue decrease to be distributed among the remaining classes.

**Q. HOW DO YOU PROPOSE TO ALLOCATE THE $41.8 MILLION REVENUE REDUCTION AMONG THE REMAINING CLASSES?**

A. My proposal is to allocate the revenue decrease on the basis of class shares of kWh consumption. I view this as a compromise allocation. The kWh methodology produces a more favorable revenue reduction for higher load factor customer classes than an equal percentage revenue decrease. The resulting allocation will be more similar to AE's proposal, inasmuch as AE's CCOS study produces more favorable results for high load factor customer classes. Schedule CJ-6 sets out the proposed allocation of the revenue decrease among customer classes. If the IHE approves a different revenue reduction than ICA's proposal, the same allocation method should be used.

## VI. RATE DESIGN

### A. Residential Rate Design

**Q. WHAT MATTERS WILL YOU ADDRESS RELATED TO AE'S PROPOSED RESIDENTIAL RATE DESIGN?**

A. The principal components of the residential rate design pertain to the fixed customer charge, summer/winter differential, and the tiered energy rate. Furthermore, ICA will address future potential changes, as well as the AE proposal for the rate design requested in this case. The AE rate filing discusses the utility's views regarding the direction of future potential changes.

#### 1. Customer Charge

**Q. WHAT IS AE'S PROPOSAL REGARDING THE RESIDENTIAL CUSTOMER CHARGE?**

A. AE proposes the no change to the residential customer charge, which is $10 per month. ICA agrees that the current customer charge should remain unchanged.

**Q. DO YOU AGREE WITH AE'S OVERALL POSITION WITH RESPECT TO THE RESIDENTIAL CUSTOMER CHARGE?**

A. No. AE contends that the current residential customer charge is substantially below cost, and suggests that the level of customer charge should be increased in the future. ICA disagrees with both contentions. AE's position is not surprising, because it is consistent with pricing strategies commonly espoused by utilities. Raising customer charge levels creates a constant revenue stream, thereby shifting risk to customers. Furthermore, this pricing strategy frequently involves shifting cost recovery to the least elastic[74] component of rates; customers have no means of controlling the size of their bill in response to a customer charge increase---other than leaving the system. While AE's interest in revenue stability is understandable, a pricing strategy based on raising fixed monthly charges is not consistent with the interests of customers. The only economic function of a customer charge is to ration access to the utility system. However, this access rationing role is not consistent with public interest rate regulation. Electric utility service is considered a human necessity in modern society, and public interest regulation encourages universal utility service. The only rate components which provide useful economic price signals are usage charges. In the case of residential rates, minimizing the customer charge moves cost recovery to energy charges, which provide a useful conservation price signal. For this reason, maintaining a low customer charge enhances the customer's ability to control the size of the electric bill.

**Q. HOW DOES AE'S RESIDENTIAL CUSTOMER CHARGE COMPARE TO THE CUSTOMER CHARGES OF OTHER BUNDLED ELECTRIC UTILITIES**

[74] "Elasticity" is an economic term for the change in customer usage which occurs in response to changes in price.

**REGUATED BY THE TEXAS PUC?**

A. AE's $10 residential customer charge is higher than any of the other bundled electric utilities: $6.00 for ETI; $5.00 for El Paso Electric Co.; $8.00 for SWEPCO; and $9.50 for Southwestern Public Service Co.

**Q. DO YOU AGREE WITH AE'S CLAIM THAT THE COST-BASED RESIDENTIAL CUSTOMER CHARGE IS $22 PER MONTH?**

A. No. This position is based on a fully loaded customer charge derived from the CCOS Study. Given its nominal pricing function, the customer charge should only recover costs which vary directly with the number of customers. Generally, the costs which vary directly with customer count consist of the direct costs of meters, service lines, meter reading, and customer billing. Although the AE's CCOS study shows a customer unit cost higher than its request, the CCOS includes costs in the customer unit price which are only indirectly associated with customers. The CCOS calculated customer unit cost includes a portion of general overhead costs, such as A&G expense, which do not vary with changes in the number of customers. However, even if the fully loaded customer charge calculation is accepted, ICA's CCOS indicates a cost of $14.35, which is significantly closer to the current $10 charge than AE's claimed cost.

**Q. HAVE YOU ESTIMATED A RESIDENTIAL CUSTOMER CHARGE LEVEL FOR AE WHICH IS DIRECTLY RELATED TO THE NUMBER OF CUSTOMERS?**

A. Yes. My estimate of the customer charge directly related to the number of customers results in a $9.35 monthly charge. Since the existing customer charge is $10, the current customer charge is more than compensatory. The calculation includes costs for meters, services, meter reading, customer accounting, and customer service, but excludes uncollectibles, General Fund Transfer, and A&G expense embedded in the customer expense amounts. GFT is a return component which should not be recovered through the expense elements of the customer charge. Therefore, I estimated the removal of GFT and A&G from the components other than meters and services. The calculation is consistent with the historic Commission practice for evaluating the customer charge level of bundled electric utilities.[75] The calculation is set out on Schedule CJ-7.

**Q. GIVEN AE'S VIEW REGARDING FIXED CHARGES, SHOULD AE CONSIDER RESIDENTIAL DEMAND CHARGES IN THE FUTURE?**

A. No. Demand charges, which establish monthly charges based on an hour or less of maximum usage, are not well suited for residential rate design. Demand charges have caused considerable bill impacts and confusion for small commercial users who were moved off of energy rate tariffs; the impact and negative reaction is likely be multiplied many times over for residential customers. The only TDU in Texas which attempted to implement mandatory residential demand charges (McAllen Division of Sharyland) did so only briefly because of the major bill impacts and confusion. Optional Time of Day rates are a better alternative in the residential class.

### 2. Residential Tiered Energy Charges

**Q. WHAT IS AE'S RATE STRUCTURE FOR COLLECTING ENERGY CHARGES?**

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[75] *See* for example *Application of Houston Lighting & Power Company*, Docket No. 8425, PFD at 264, 16 P.U.C. BULL. 2199 and 2488 (June 20, 1990).

A. AE has an inverted block rate structure in the residential class. An inverted block means that each successive block or tier of energy usage has a higher energy rate. AE has five tiers for inside city customers and three tiers for outside city customers. The advantage of an inverted block structure is that it provides a strong price signal for conserving energy. In addition, the price signal may produce environmental benefits. A steeper inverted block structure can be accomplished with more tiers of usage, and AE has exploited this characteristic with five tiers for inside city customers. The cost basis for an inverted block arises when long run marginal costs are higher than embedded costs; under those conditions, increased usage inflates the future costs per kW or kWh to be collected from all customers.

**Q. DO YOU AGREE WITH AE'S ANALYSIS THAT HIGH USAGE TIERS ARE PAYING ABOVE COST WHILE LOW USAGE TIERS ARE PAYING BELOW COST?**

A. Not necessarily. This appears to be an attempt to use the CCOS study to define whether customers of various usage levels are above or below cost. In my opinion, this is not an appropriate use of the CCOS study. The CCOS allocates costs to customer classes, not to individual customers or customers at various tier levels. The allocation factors for assigning costs to classes are not the same measures as the rate components within the rate structure. In my view, the attempt to graft CCOS results to individual customer usage levels can produce serious inaccuracies. In essence, an assumption is made that energy use has a strict linear relationship with the various demand allocators in the CCOS, which may not be correct. Moreover, this type of analysis may ignore higher summer load factors in low use tiers which include customers without air conditioning or other appliances. Moreover, a more appropriate cost analysis for rate design purposes would involve marginal costs rather than embedded costs, because rate design focuses on the appropriate price signals.

**Q. WHAT IS AE'S PROPOSAL WITH RESPECT TO THE FIVE TIERED RATE STRUCTURE?**

A. AE flattens the tier structure somewhat. This involves higher rates in the first tier and lower rates in higher tiers. AE's objective is to increase revenue stability from the inverted block structure. The bill impact by customer usage is illustrated on Schedule H-3. Up to 750 kWh, the average customer bill will increase 4% - 7%. In the 750 kWh – 1000 kWh usage category, the average bill impact declines slightly, and the decrease grows to -2.5% in the 1750 – 2000 kWh group. The average percentage decrease for the highest usage levels is just above -1%.

**Q. DO YOU AGREE WITH THIS APPROACH?**

A. I don't disagree with the objective of producing more revenue stability in the rate structure. The utility's revenue collections will be particularly sensitive to weather conditions with steeper tiers. The five tier structure also can produce volatile results for customers too. During an abnormally hot summer, customers may unknowingly be pushed into a higher tier than they are accustomed, which could produce rate shock. However, AE's approach to flattening the rate structure is problematic, because it produces bill increases in the first tier of usage. Many of these low use customers have little room to further reduce consumption, and may be unable to lower their bills in response to the higher rate.

**Q. DO YOU HAVE AN ALTERNATIVE APPROACH?**

A. The ICA's revenue reduction recommendation assigns part of the system base revenue reduction to the residential class. In addition, the ICA's proposed revenue reduction is more than twice the size proposed by AE. A portion of the residential share of the base revenue reduction can be used to fund the changes to the rate structure without increasing rates for the lowest tier. Thus, AE could achieve its desired reduction in the steepness of the tier structure, but also maintain the basic rate levels for the first tier. After using part of the base revenue reduction for this change, any remaining residential base revenue reduction amount should be used to reduce all tiers equally.

**Q. SHOULD AE MAKE ANY CHANGES IN THE NUMBER OF TIERS FOR INSIDE CITY CUSTOMERS?**

A. This is an issue which AE should study before its next rate case. However, changing the number of tiers in this case would be overly disruptive and could produce unintended consequences. However, there are potential advantages to reducing the number of tiers to three or four. These advantages include: less revenue volatility, fewer instances of customers unintentionally landing in a higher tier due to abnormal weather, and a less complicated rate design which can be more easily understood. Additionally, if AE considers the possibility of unifying the inside/outside city rate structures in the future, it may be easier to do so with fewer tiers. The scope of such a study should include an analysis of bill impacts for various options, as well as a more thorough analysis of the utility's long run marginal costs relative to embedded costs. An analysis of long run marginal costs would provide better support for various tier options.

### 3. Summer / Winter Differential

**Q. WHAT IS AE'S PROPOSAL WITH RESPECT TO THE SUMMER/WINTER BASE RATE DIFFERENTIAL?**

A. AE proposes to eliminate the base rate summer/winter differential, which lowers rates in the winter. In addition, AE proposes to include, for the first time, a summer/winter differential in the power supply adjustment (PSA).

**Q. DO YOU OBJECT TO THIS PROPOSAL?**

A. No. High summer bills produce the most difficulties for household budgets, and potentially the elimination of the base rate summer/winter differentiate will moderate bill impacts and reduce customers' need for deferred payment plans. To some extent, this can be viewed as a trade-off between putting the summer/winter differential in the PSA versus base rates. From a costing standpoint, the differential is only related to the production function.[76] Some level of summer/winter differential is justified, but applying the differential to both the PSA and base rates will likely result in an excessive summer rate. Applying the differential only to the PSA, based on ERCOT price differentials, provides a stronger connection to documented seasonal cost differences and is more consistent with the principles behind the 12 CP and BIP production demand allocation

[76] For instance, for unbundled electric utilities, the Texas PUC does not permit a summer/winter differential in delivery rates. Bundled utilities are permitted to apply such a differential to base rates though.

methods. It should be noted that the summer/winter differential is likely to be more moderate when applied to the PSA rather than the base rates.

**B. Small Commercial Rate Design**

**Q. WHICH CLASSES CONTAIN SMALL COMMERCIAL CUSTOMERS?**

A. The Sec. <10 kW (S1) and the lower end of the Sec. 10 – 300 kW (S2) classes contain customers who can generally be characterized as small commercial. The S1 class has a customer charge / energy charge rate structure. The S2 class also pays a demand charge.

**Q. DO YOU OBJECT TO THE RATE DESIGN APPLIED BY AE TO THOSE CLASSES?**

A. Generally, no. As I will discuss in the next sub-section, I object to AE's proposal to terminate the HOW rate rider for these classes. For most small commercial customers in the S2 class, the rate structure impacts are minor in comparison to the effect of the base revenue reduction assigned to the class.

**Q. HAS AE PROPOSED ANY BILLING LIMIT PROVISIONS WHICH ARE NOTABLE FOR SMALL COMMERCIAL CUSTOMERS?**

A. Yes. AE proposes a 20% load factor floor for the S2 class. Since low load factor customers in the S2 class tend to be smaller sized customers, this will affect small commercial customers. Load factor is the ratio of a customer's average annual demand to the customer's maximum demand (the basis for demand charge billing). Customers who concentrate their energy use in a small number of hours will exhibit a low load factor and incur a demand charge that is high relative to total usage. If a S2 customer exhibits a load factor below 20%, the new floor provision will impute a lower level of billing demand. I agree with this new provision, because it will mitigate rate shock among certain types of small commercial customers. This provision is analogous to a low load factor mitigation tariff used by Southwestern Public Service Co., commonly called "the Rule of 80." In my view, special rates for customers with exceptionally low load factors are justified because the customer's unusual load characteristics are not well suited for demand charge billing. I would also note that the 20% load factor floor also will benefit some HOW customers.

**Q. DO YOU HAVE ANY CONCERNS ABOUT HOW AUSTIN ENERGY WILL APPLY ITS RATE DESIGN PRINCIPLES TO SMALL COMMERCIAL CUSTOMERS IN THE FUTURE?**

A. Yes. AE emphasizes adherence to strict fixed/variable pricing and states its desire to pursue pricing which promotes high load factor. According to AE, high load factor is "efficient." My concern is that AE will continue to increase the customer charge for S1 and S2 in the future and shift more costs from energy rates to the demand charge when S2 rates are changed again.

**Q. DO YOU HAVE ANY COMMENTS RELATED TO AE'S POSITION THAT PROMOTING HIGH LOAD FACTOR IS "EFFICIENT?"**

A. Yes. The pricing policy should distinguish between different types of efficiency. Load factor promotion is associated with static engineering efficiency, and typically is a response to excess generating capacity. Economic efficiency, on the other hand, is more focused on the long run impact of prices on the utility's marginal costs. Rather than simply pursuing higher load factors, AE's pricing objective should balance both types of efficiency. In my opinion, AE should be cautious in strictly adhering to the objective of shifting costs from variable rates to demand charges. Over the long run, pursuit of higher load factors may lead to higher costs and economically inefficient behavior. Higher system load factors may shift the generation capacity expansion path toward higher capital cost baseload generation. In addition, increased system load factor may create upward pressure on the required generation reserve margin necessary to achieve a given level of reliability. Finally, for some customers, the maximum demand as measured by the demand charge is poorly related to the coincident demands which are relevant to system load factor. Furthermore, aside from the efficiency criteria, promotion of high load factor may conflict with Austin's objective of reducing environmental emissions. Since load factor promotion generally leads to more megawatt hours (Mwh) of generation, the environmental effect is likely to be negative.

**Q. DO YOU FAVOR INCREASING THE S1 AND S2 CUSTOMER CHARGES IN THE NEXT RATE CASE?**

A. No. AE should avoid raising the small commercial customer charge, if possible. Similarly, AE should refrain from shifting costs from energy rates to the demand charge in the next rate case.

**C. Houses of Worship (HOW) Rate Design**

**Q. PLEASE DESCRIBE THE CURRENT HOUSE OF WORSHIP (HOW) RATE AND THE "TRANSITION" FROM THE LAST RATE CASE.**

A. Austin Energy proposes to end the current discount to Group Religious Worship Accounts, also referred to as "Houses of Worship" or HOWs. Austin Energy had proposed to end the discount in the 2012 rate case, moving HOWs into the commercial rate class. The City Council approved transitioning away from the discount by establishing a transition maximum charge to mitigate rate shock"[77], currently set at 13.015 cents per kWh. The Council also closed the discount rate to new customers, but later reversed that policy, allowing new facilities to take advantage of the rate.[78] In addition, weekend hours are not considered when determining billed peak demand.[79] Austin Energy also states that staff worked "proactively" with group religious worship accounts to offer advice on energy management and to access energy efficiency services.

**Q. WHAT IS AUSTIN ENERGY'S PROPOSAL WITH REGARD TO THE HOW RATE?**

A. Austin Energy proposes to end the transition period and fully move HOW into the commercial rate classes. This means that the 13.015 cents per kWh would no longer apply and demand would be measured at peak usage.[80]

**Q. WHAT IS THE STATUS OF THE EL PASO ELECTRIC HOUSE OF WORSHIP RATE?**

A. In the Tariff Package Austin Energy states that the Public Utility Commission of Texas has largely discontinued HOW rates. In the 2012 rate case Austin Energy cited El Paso Electric (EPE) as precedent. In the 2009 EPE rate case, churches were caught in the

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77 Tariff Package at 6.8.3, Bates 174.

78 Tariff Package at Bate 174, referring to Ordinance No. 20130909-003.

79 http://austinenergy.com/wps/wcm/connect/ab6d045c-643e-4c16-921f-c76fa0fee2bf/FY2016aeElectricRateSchedule.pdf?MOD=AJPERES.

80 See Tariff Package at 6.8.3 and Bethany Church 1-5.

middle of a rate class restructuring, losing their separate energy only rate. After the rates went into effect, churches faced major bill impacts, and the Texas PUC subsequently ordered a transition rate, which is still in effect. EPE has a new rate case (Docket No. 44491) pending now, and the utility is proposing to extend the transition rate for HOW, phasing it out over a period of years. The current EPE transition rate is similar to the HOW cap for Austin Energy. The EPE proposal is to have a cap of $0.1325/kwh until its next rate case, then a cap of $0.1525 for 12 months, then a cap of $0.1725 for 12 months, and finally no cap. The length of the new transition period will depend on the decision in the pending rate case. However, realistically, the Commission will consider whether to extend the transition period in the following rate case, if necessary. As stated by EPE's rate design witness, James Schictl, "As a practical matter, EPE and other parties will have another opportunity to address the rate limiter in EPE's 2017 rate case. In addition, EPE fully absorbs the cost of the limiter…"[81]

**Q. WHAT IS THE EFFECT OF AUSTIN ENERGY'S PROPOSAL TO END THE HOW TRANSITION?**

A. Houses of Worship in Austin will pay approximately $1 million more in rates[82] under Austin Energy's proposal. The impact on individual Houses of Worship is not uniform. Some will see little change under the new rates, some will even benefit due to other rate changes proposed by AE. However, many smaller churches, particularly those in the S1 class and those at the lower end of S2 eligibility threshold will experience significant bill

[81] Rebuttal Testimony of James Schictl at 82, Docket No 44941.

[82] Bethany Church 2-2, ICA 1-9, ICA 3-26, Attachment 1.

increases that I would describe as rate shock.[83] A variety of factors coincide in this rate request to create rate shock conditions; these include loss of the discount, loss of the weekday-only demand measurement, AE's effort to place greater cost recovery on fixed charges; and expansion of the size of the S2 class from 50 kW to 300 kW as the upper limit.

**Q. IS THE CONVERSION OF MANY CHURCHES FROM ENERGY CHARGES TO DEMAND CHARGES A MAJOR CAUSE OF RATE PROBLEMS?**

A. Yes. For instance, some of the churches are principally off-peak, and have low load factors. For example, some churches may only use power for lights and heating/air conditioning only for a brief number of hours on the weekend, but the demand charge causes those customers to incur that maximum hour charge as if they had used power every day of the week. These customers would receive bills which exceed their cost impact on the system. Demand charges are not based on coincident peak usage. These customers have limited or no impact on peak demand generation facilities, which are allocated in the CCOS on coincident peak hours. They have no impact on transmission facilities which are allocated on a four coincident peak hours in the summer. Although distribution facilities are allocated in the CCOS study based on class non-coincident peaks, the actual impact of these customers' non-coincident peaks will depend on the demands for the local area in proximity to the church. In addition, the off-peak characteristic of HOW customers is likely to provide considerable benefit for distribution sizing in the upstream segments of the distribution system which are sized for a larger

[83] ICA 3-26 Attachment 1 shows the value of the lost discount compared to bills.

local area which encompasses numerous types of customers. In short, HOW customers provide beneficial load diversity (as measured by customer peaks vs. system non-coincident and coincident peaks) which is not recognized by demand charge pricing.

**Q. IS AUSTIN ENERGY PLANNING TO PERFORM STUDIES THAT ARE RELEVANT TO THE HOW RATE?**

A. Yes. Among the studies Austin Energy proposes prior to the next cost of service assessment is a study of the rate structure for the S1 class and a study of demand charges for customers peaking outside AE system peak.[84] There are approximately 58 HOW in the S1 class[85] and many HOW accounts experience peak on weekends, outside the AE system peak. Both of these studies could result in rates that would mitigate the rate shock that some HOWs will experience under the proposal in this rate case.

**Q. WHAT ARE YOUR CONCERNS ABOUT DISCONTINUING THE HOUSES OF WORSHIP TRANSITION?**

A. My first concern is the rate shock that will be experienced by some of the Houses of Worship. Avoiding rate shock is a well-established principle of utility ratemaking. In the current rate case Austin Energy is not proposing to raise rates to any customer class, and rate for most will be lowered. It is not fair to subject HOWs, some of them very small and relying on volunteer staff, to experience significant rate increases and do nothing to mitigate this rate increase.

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[84] AELIC 8-4, Attachment 1 page 27 of 35.

[85] ICA 1-10, bill frequency = 709 in FY 2014.

Second, I disagree with moving the HOWs off the transition discount when Austin Energy plans to perform rate studies that might result in a more appropriate rate treatment for HOW, including a study of peak usage measurement in the commercial class and the rate structure of the S1 class.[86] A HOW with peak usage on the weekend is exactly the type of customer who could benefit from the results of a study addressing off peak demand. Many of the smallest HOW are in the S1 class and may benefit from a revised rate structure. These studies should be done prior to any rate change.

Third, understanding and controlling demand is challenging for many customers, including smaller HOW who may rely on volunteer or part time staff and almost certainly do not have access to an energy manager. The changes Austin Energy is proposing to the S2 class adds another layer of complexity to the HOWs who are losing their discount.

**Q. WHAT ARE YOUR RECOMMENDATIONS?**

A. I propose the following:

- Extend the transition for HOWs—retain the cap of 13.015 cents per kWh and the practice of measuring peak usage during weekdays. Preferably, AE should absorb the discount, instead of re-allocating the cost to other customers, consistent with the recommendation of AE's consultant, NewGen.
- The transition should not end until after the two studies referenced above have been completed and the next rate case is completed.[87]
- Include outreach to HOWs during the study periods.
- Continue outreach to HOWs, prioritizing those who would experience the largest rate increase absent the transition. Austin Energy should conduct trainings to help HOWs understand and manage demand. It should also work with HOWs to identify facilities that might benefit from option time-of-use rates and offer to run "shadow bills" comparing rates under current usage with and without the time-of-use option.

[86] See Appendix E.

[87] In addition, the IHE should order AE to include HOW customers in the two studies above.

# VII. POLICY ISSUES

## A. Below Average Customer Satisfaction

**Q. WHAT DOES AUSTIN ENERGY SAY ABOUT CUSTOMER SATISFACTION IN THE RATE FILING PACKAGE?**

A. Austin Energy does not directly address customer satisfaction. Austin Energy addressed "Customer Success" on p. 3-38 (Bates 067) stating: "Austin Energy's guiding principle is to make it easy for its customers to work with the utility and to provide them with products and programs they regard as valuable." This section of the Tariff Package provides descriptive information on Energy Conservation programs, Green Building, Energy Conservation Audit and Disclosure, Solar, and Customer Care.

**Q. DID AUSTIN ENERGY PROVIDE ANY INFORMATION ABOUT CUSTOMER SATISFACTION?**

A. Yes. ICA 2-1 asked for results of recent customer satisfaction surveys. Austin Energy provided the following information for FY 15:

- The overall satisfaction survey rating for Austin Energy was 59%
- Satisfaction for the walk-in service centers averaged 88% for residential and commercial customers
- Satisfaction with the residential rebate program was 80%

**Q. WHAT IS THE OVERALL SATISFACTION SURVEY?**

A. According to Austin Energy's response to ICA 5-6: "This survey is conducted by phone and is written by Austin Energy staff and conducted by a consultant with a call center. The survey was conducted on 120 residential customers in both FY 2015 and FY 2014."

**Q. DID AUSTIN ENERGY PROVIDE COPIES OF THE SURVEY OR ANALYSIS OF THE RESULTS?**

A. No. Austin Energy objected to ICA 5-6 requesting the surveys, methodologies and results, of the overall customer satisfaction surveys, stating "The surveys and their detailed findings are considered competitive information and are being withheld." Austin Energy did provide detailed information on the walk-in information center satisfaction surveys and the residential rebate program surveys.

**Q. IS IT YOUR OPINION THAT 59% SATISFACTION IS AN ACCEPTABLE RATING?**

A. No. The results indicate that about 40% of Austin Energy's residential customers are not satisfied with the utility. Without seeing the detail of the surveys it is not possible to know whether the dissatisfaction is related to rates, communications, service or something else.

**Q. ARE YOU AWARE OF OTHER CUSTOMER SATISFACTION SURVEYS OF AUSTIN ENERGY CUSTOMERS?**

A. Yes. J.D. Power customer satisfaction surveys are well known by consumers and the utility industry.[88] According to the 2015 results Austin Energy is rated 654 on a 1000-point scale. It is below average for South Region Midsize Segment (average 684) and below the overall national average of 668. The J. D. Power press release highlights rates, communications with customers, and outages as key factors in their survey.

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[88] A link to the 2015 survey is found at: http://www.jdpower.com/press-releases/2015-electric-utility-residential-customer-satisfaction-study.

**Q. WHAT IS YOUR RECOMMENDATION?**

A. Customer satisfaction is a key metric of utility performance and Austin Energy should strive for significantly improved customer satisfaction ratings. It is not possible to make a detailed recommendation without knowing the survey questions and specific results behind the overall customer satisfaction rating. I recommend Council direct Austin Energy to develop a plan to improve its customer satisfaction ratings. I further recommend Austin Energy work with the Electric Utility Commission, ratepayer advocates and the public in developing, executing and monitoring the plan for improved customer satisfaction.

### B. Residential Pilot Programs, Generally

**Q. HAS AUSTIN ENERGY INCLUDED ANY PILOT PROGRAMS FOR RESIDENTIAL CUSTOMERS IN THE TARIFF PACKAGE?**

A. Yes. In the FY 2016 budget Council approved three additional pilots[89] that are included in the "Residential Service Pilot Program" section of the proposed City of Austin Tariff Schedule[90]:

- Time-of-Use Rates
- Prepayment Rates
- Plug-In Electric Vehicle Charging Rates

The Time-of-Use pilot began January 1, 2016; the Plug in EV pilot has not yet begun[91]; the prepayment pilot was slated to begin April 1, a date later revised to May 2[92].

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[89] https://assets.austintexas.gov/budget/15-16/downloads/Vol2Approved_Final.pdf. See p. 544; ICA 2-18C.

[90] Beginning at Bates 664.

**Q. DO YOU AGREE THAT AUSTIN ENERGY SHOULD CONDUCT PILOT PROGRAMS OF NEW OR OPTIONAL RESIDENTIAL RATES AND RATE DESIGNS?**

A. Yes. I agree with Austin Energy's plan to pilot and study these proposals. New and alternative rates and rate designs have the potential to provide benefits to some customers, as well as to the utility. For example, if properly structured, an opt-in time-of-use rate could help lower peak usage, both reducing peak demand and saving money for those customers with flexibility to shift their usage off peak. However, the opposite is also true—an improperly structured rate design could result in some customers seeing significantly higher bills, and/or cross subsidies across customer groups (for example, between participants and nonparticipants).

**Q. DID THE ELECTRIC UTILITY COMMISSION REVIEW OR APPROVE ANY OF THE THREE FY 16 PILOTS PRIOR TO ADOPTION IN BUDGET?**

A. No.[93]

**Q. DID THE CITY COUNCIL RECEIVE ANY BRIEFINGS ON THE THREE FY 16 PILOTS OTHER THAN DISCUSSION AND ADOPTION AS PART OF THE BUDGET?**

A. No.[94]

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91 ICA 2-21.

92 http://www.austintexas.gov/edims/document.cfm?id=252239; ICA 2-21.

93 ICA 5-10.

94 ICA 2-18, ICA 5-9.

**Q. HAS AUSTIN ENERGY PROVIDED THE COSTS OF EACH PILOT, BROKEN OUT BY CAPITAL COSTS AND OPERATIONS AND MAINTENANCE EXPENSES?**

A. No.[95] Austin Energy provided no cost information for the Time of Use and Plug-In EV pilots, stating "the reason for the pilot programs is to collect information related to O&M and capital expenses, incremental costs, and savings." For the prepayment pilot Austin Energy has identified a budget of $57,999, but has not allocated the amount between O&M and capital.

**Q. DO THE PILOTS HAVE FIRM STARTING AND END DATES?**

A. This is not at all clear. For the EV and Time-of-Use pilots, no information was provided referencing the time period the pilots would be in effect, although the tariff requires customers to remain on the pilot rate for 12 consecutive billing cycles or pay a penalty. A memo from Interim General Manager Mark Dombroski to the Mayor and City Council[96] refers to the pilots as "limited" and "temporary". The prepayment pilot was described by Mr. Dombroski as terminating in September of 2016. However, all of the pilots, including the prepayment pilot, are included in the proposed tariffs for FY 2016, and Austin Energy has referred to future "full deployment" of the rates.[97] Therefore, I assume the pilots and/or the rate designs will all be in effect beyond September of 2016.

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[95] ICA 2-12, ICA 2-21, AELIC 2-25.

[96] http://www.austintexas.gov/edims/document.cfm?id=252239.

[97] ICA 2-17.

**Q. WHAT DOES THE ELECTRIC VEHICLE PUBLIC CHARGING PILOT PROGRAM TELL US ABOUT AUSTIN ENERGY'S APPROACH TO PILOT PROGRAMS?**

A. The Electric Vehicle Public Chairing Pilot began in FY 2012, four years ago. Yet Austin Energy refers to the pilot as being it is "early stages" and states it has not conducted a comprehensive cost of service examination to verify if there are subsidies created by the program.[98]

**Q. DO YOU AGREE WITH AUSTIN ENERGY'S APPROACH TO THE PILOT PROGRAMS?**

A. Not entirely. As I stated previously, there is value to both the utility and its customers to explore new or alternative rates through pilots prior to full deployment. However, I see several flaws in Austin Energy's approach:

- **Austin Energy's pilot do not have firm time limits.** A rate should not go on for years under the "pilot" designation. It is concerning that Austin Energy would refer to the four-year-old public charging station pilot as "in its early stages."
- **Austin Energy has not fully developed the terms and conditions of the pilot, its goals, customer education, performance criteria and evaluation metrics up front**. For example, Austin Energy Low Income Customers asked detailed questions about the prepayment pilot. In responses provided less than one month prior to the (at that time) April 1 start date, Austin Energy responded to several key questions about the pilot and customer protections with answers such as "currently reviewing" and "not yet determined".[99]
- **Austin Energy has not sufficiently engaged city policymakers in the design and review of these pilots**. The ICA team was surprised by how little public discussion there was concerning the pilots, particularly the prepayment pilot which Austin Energy identified internally as potentially controversial[100]. The role of the Electric

[98] NXP/Samsung 1-90.

[99] See responses of March 10, 2016 to AELIC 2-1, 2-8, 2-9, 2-10, 2-12, 2-15.

[100] ICA 2-18 Attachment 4, p. 28 of 38.

Utility Commission is to: "Review and analyze all policies and procedures of the electric utility including the electric rate structure, fuel costs and charges, customer services, capital investments, new generation facilities, selection of types of fuel, budget, strategic planning, regulatory compliance, billing procedures, and the transfer of electric utility revenues from the utility fund to the general fund,"[101] yet Austin Energy did not brief the EUC on the pilots. Although the Council has an Austin Energy Oversight Committee, the only presentation given Council on these pilots came during the FY 16 budget process, a time when Council members are reviewing a massive amount of information related to the entire city budget.

**Q. WHAT ARE YOUR RECOMMENDATIONS?**

A. With regard to pilot projects in general:

- Proposed pilots should be reviewed by the Electric Utility Commission and the Council, separate and apart from the budget process.
- Where a pilot has identified stakeholders, such as low income advocates, Austin Energy should consult these groups about pilot goals and design, prior to initiating that pilot.
- Pilots should be given a firm end date; no pilot should go on indefinitely or for more than two years without a comprehensive review. If it is determined that additional study is needed, the pilot could be extended.
- Austin Energy should fully develop the terms and conditions of the pilot, its goals, customer education, performance criteria, potential cross subsidies, and evaluation metrics prior to initiating a pilot.

### 1. Prepayment Pilot Program Concerns

**Q. DO YOU HAVE SPECIFIC CONCERNS ABOUT THE PREPAYMENT PILOT?**

A. Yes. As Austin Energy internal documents reveal, prepayment programs have "high-level risks", including potential disapproval by customer advocacy groups or by city council members.[102] Therefore, it is imperative for success that AE include stakeholders in discussions regarding the design and evaluation criteria for any prepayment pilot

[101] http://www.austintexas.gov/euc.

[102] AE Response to ICA 2-18, p. 200.

program at the earliest opportunity. Prepayment pilots can be complicated and are often controversial. The following issue includes some of the concerns likely to be raised by consumer advocates and which should be addressed in a stakeholder collaborative:

1. **Bypass of Billing and Disconnection Protections**. Austin Energy's proposal for a prepayment program includes the following "fine print" provisions, which would apply different service conditions, and arguably less consumer protections, for participants in the program, as compared to normally billed residential customers:

- In lieu of a written notice of disconnection, Austin Energy will provide program participants with a notice by text message, email, or phone call to alert them when the account balance is at or below a projected five (5) day usage. It is the participant's sole responsibility to provide Austin Energy with current and correct contact information for such notice message; nor is it Austin Energy's responsibility to verify that the notice message was delivered nor refrain from disconnecting service, if it cannot deliver the notice message due to insufficient or incorrect information.
- Regulations and policies concerning disconnection of service due to weather, critical medical conditions, or other circumstances shall not apply to service under this rate schedule.[103]

Disconnection rules and policies designed to provide adequate notice of disconnection and to protect the health and safety of consumers from disconnection during extreme weather conditions should not simply be bypassed or waived, at least not without the creation of equally protective provisions that apply to prepayment participants.

2. **Low-income customers may be targeted, and disconnections may rise dramatically.** Even if a prepayment program is not specifically targeting low income or payment troubled customers, the benefit of not having to supply a security deposit in

[103] AE Response to ICA 2-18, p. 236.

order to have prepayment service is likely to attract such customers. Other utilities have experienced a higher number of disconnections and spikes in disconnections through their prepayment programs. One utility reports that only 60% of its prepayment participants have not experienced some disconnection activity.[104]

**Q. WHAT IS YOUR RECOMMENDATION?**

A. I recommend Austin Energy develop a collaborative of stakeholder groups, including low income advocates, to review and make recommendations on the prepayment pilot, including adopting consumer protections equivalent to current consumer protections. In addition the collaborative should address ways to ensure a prepayment plan is not targeted at lower income households.

### C. "Pick Your Own Due Date" Option for Consumers

**Q. WHAT IS A "PICK YOUR OWN DUE DATE" OPTION FOR UTILITY CONSUMERS?**

A. Also called "Preferred Due Date" or "Pick-A-Date", this option allows the utility to offer each customer the ability to choose the timing of their monthly billing cycle, allowing for a customized due date each month that best suits that customer's bill paying patterns. This option is particularly convenient for customers on fixed incomes who wish to time their bill payments to match the receipt of their monthly payroll check or benefit check. "Pick Your Own Due Date" programs are growing in popularity among investor-owned and municipal utilities. Several City Council members inquired about the possibility of

[104] AE Response to ICA 2-18, p. 181.

AE implementing such a program during the most recent City of Austin Utility Oversight Committee meeting.[105]

**Q. CAN YOU GIVE AN EXAMPLE OF HOW IS THIS OPTION IS MADE AVAILABLE TO CONSUMERS BY ANOTHER UTILITY?**

A. The Texas PUC permits the electric utilities that it regulates to offer customers the option of choosing their own due date. Entergy Texas provides this explanation of its program to consumers on its website:

> Q. Can I change the date that my bill would be due each month? I live on a fixed income and my check comes at the first of the month, but your bill is due around the 20th of each month.
>
> A. Yes, Entergy understands that some customers receive their income checks on a monthly basis. Our **Pick-A-Date** program provides you the ability to select a billing date that best suits your situation. Once set up in the program your account will bill on the date selected. You can sign up for Pick-A-Date by logging on to My Account Online.[106]

**Q. WHAT IS THE CURRENT STATUS OF AUSTIN ENERGY'S ABILITY TO OFFER THIS OPTION TO ITS CONSUMERS?**

A. Austin Energy states, "At this time, customers are not allowed to choose their due date. Research is required to determine the technical and operational changes required to allow customers to change their bill due date. However, testing is currently underway for the required technical changes to determine feasibility of the program."[107]

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[105] April 28, 2016 committee meeting.

[106] Frequently Asked Questions: http://www.entergy-texas.com/faq/faq_consumer.aspx#b8.

[107] AE Response to ICA 2-2.

**Q. WHAT IS YOUR RECOMMENDATION?**

A. Austin Energy should be required to implement a "Pick Your Own Due Date" option for consumers as soon as it is technically feasible to do so, and then publicly promote this billing accommodation to its consumers.

### D. Timing of Next Rate Review Proceeding

**Q. WHAT DOES AE SAY ABOUT THE POTENTIAL TIMING OF THE NEXT RATE REVIEW PROCEEDING?**

A. The Austin Energy proposal in this rate review proceeding states:

> Due to the significant deviation from cost of service for some customer classes and the list of issues for further research, Austin Energy suggests that the next cost of service update be conducted upon the conclusion of these studies in two to three years, rather than the maximum five years included in current City Council policy.[108]

**Q. WHAT DO YOU RECOMMEND?**

A. I agree with the idea that, following the conclusion of this proceeding, Austin Energy's cost of service should be examined more frequently than five years, particularly in consideration of the many issues that Austin Energy plans to study in the interim,[109] and the several issues that I am proposing to be deferred for study until the next proceeding. Allowing for a thorough and transparent analysis of Austin Energy's cost of service every 2-3 years, if possible, is a good policy, and is much preferable to allowing rates to change over time without such a full review.

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[108] Tariff Package, p. 029.

[109] Tariff Package, Appendix E, pp. 372-373.

### E. Restricting Piecemeal Rate Changes

**Q. WHY IS IT PREFERABLE FOR ELECTRIC RATES TO CHANGE ONLY AFTER A FULL COST OF SERVICE REVIEW?**

A. There is an interrelationship among many cost of service components (i.e., expenses, investments, revenues) within a test year. When adjustments are made to electric rates for one item of expense outside of a full rate review of all components, then a mismatch can occur which distorts the overall cost of service. For instance, rates could be increased due to an increase in one expense, while ignoring a reduction that occurred in another expense during the same time period. Austin Energy already has three pass-through mechanisms (the Power Supply Adjustment charge, the Regulatory Charge, and the Community Benefit Charge) which can change electric rates in isolation of the changes that may be occurring to base rates. It is important that no more isolated changes be allowed in order to preserve the fairness and affordability of electric rates overall.

A guiding principle advanced by Austin Energy is that "The rate review process should be transparent, including public involvement".[110] Thus far, the current rate review proceeding has allowed unprecedented public involvement and scrutiny of Austin Energy's electric rates with the goal of producing an independent opinion regarding the level and allocation of the cost of service. Rate changes, including changes in rate design, that occur subsequent to this proceeding are not likely to be subjected to the same level of transparency and scrutiny, and have the potential to distort the relationship of rates to the overall cost of service. I believe that it is important to ensure that the rate

[110] Tariff Package, p. 017, Principle #8.

changes resulting from this proceeding will remain in place until the next full rate review, without the creation of any new mechanisms that have the potential to cause isolated changes to electric bills.

**Q. WHY ARE YOU CONCERNED ABOUT RATE CHANGES BETWEEN RATE CASES?**

A. The Tariff Package makes references to changes that would or could be implemented outside of this rate case. For example, "Looking beyond year one, there are many rate-making consideration related to moving all customer classes closer to cost of serve. These considerations include: altering the number of years over which changes can be made, modifying the number of incremental steps necessary to move closer to cost of service, adjusting the steepness of the five Residential tiers, reducing the number of Residential tiers, and changing the magnitude of the customer charge."[111] In response to a question, Austin Energy also stated: The City Council can adopt changes to the residential rates, the customer charge and rate design at any time, including prior to the filing a new rate case."[112]

**Q. WHAT IS YOUR RECOMMENDATION?**

A. I recommend that Council should not adopt changes in rates or rate design, outside of the already established PSA and pass-through charges, during the time period in between rate review proceedings.

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[111] Tariff Package Bates p. 024.

[112] ICA 2-8. See also ICA 2-9 and 2-10.

### F. Issues for study prior to the next rate review

**Q. DOES AUSTIN ENERGY PROPOSE ANY STUDIES OR RESEARCH PRIOR TO THE NEXT RATE REVIEW?**

A. Yes. Appendix E[113] to the Tariff Package lists 8 proposed studies address both residential and nonresidential rate design. These include:

Residential:

- Review tier structure of residential rates
- Lifeline study of residential energy uses
- Study customer-related cost recovery charges for multi-family, single-family and solar-installed residences;
- Charges for three-phase residential customers

Non-Residential:

- Rate structure for Secondary Voltage Service 1
- Downtown network rates
- Peak usage measurement
- Power factor charges versus Kilovolt-ampere reactive ("kvar") charges

**Q. DO YOU AGREE WITH THESE STUDIES?**

A. Yes. With regard to the residential studies, the four proposed studies are inter-related questions involving an analysis of costs and cost allocation, and decisions regarding rate design. Austin Energy has often referred to the customer charge as being below cost, a conclusion with which I disagree. Focusing on these issues before the next rate review, with the recommendations I make below, will be beneficial to residential customers. As described earlier in my testimony, the studies related to the secondary classes are needed

[113] Tariff Package, Appendix E, Bates p. 372-373.

to address disparities for some customers, including Houses of Worship and others in the lower band of the S2 class.

**Q. WHAT IS YOUR RECOMMENDATION?**

A. I recommend the following:

- The identified studies should be completed prior to the next rate review.
- Austin Energy should engage the Electric Utility Commission and stakeholder groups during the study process. Stakeholder groups for residential customers should include groups such as residential consumer advocates, low-income advocates, solar advocates and representatives of ratepayers outside the City. Houses of Worship and representatives of small business should be included as stakeholders for the non-residential studies.
- Austin Energy should provide technical expertise to the EUC and stakeholder groups during these studies. It is essential for the public, and the Council, to know the bill impacts of various proposals that could be considered under each of these studies. The EUC and most stakeholders typically would not have access to the technical assistance to run alternative rate designs, review the final approved cost of service study, etc.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

# SUMMARY OF QUALIFICATIONS

## CLARENCE JOHNSON

**EDUCATION** Bachelor of Science, Political Science, University of Houston.

Master of Arts, College of Social Science (Interdisciplinary/Urban Studies), University of Houston.

**EXPERIENCE** Mr. Johnson has more than 25 years experience as an expert witness and analyst related to electric and telecommunications utility issues.

**CURRENT EMPLOYMENT** Mr. Johnson currently provides professional consulting and analytical analyses regarding regulatory and public policies related to public utilities and the energy industry.

**PREVIOUS EMPLOYMENT 1983-2008** From September 1983 to June 2008, Mr. Johnson was a Regulatory Analyst for the Office of Public Utility Counsel. He was the professional staff person with primary responsibility for advising the Public Counsel on economic and regulatory policy issues. His responsibilities included: presenting expert testimony on regulatory matters; research related to rate filings of regulated public utilities; acting as a non-testifying expert and advising attorneys in cross-examination of witnesses and development of trial exhibits for utility regulatory proceedings; analyzing policies and practices for regulating public utilities; and preparing comments on proposed Public Utility Commission rules; assisting financial and economic staff in the development and preparation of testimony; providing expert testimony on selected issues; preparation of reports to the Legislature regarding the utility regulatory process.

**EMPLOYMENT BEFORE 1983** During the period 1977 to 1983, Mr. Johnson extensively engaged in analysis and supervision of public interest advocacy programs. He directed two non-profit corporations involved in public policy research from 1978 to 1980 and 1982 to 1983, respectively; responsibilities included overall management of the corporations, negotiation and management of grants and contracts, supervision of research activities, and presentations of research findings to legislative and administrative governmental entities. From 1980 to 1982, he also performed policy analysis and substantive research on the impact of governmental policies for two publicly-funded entities. His responsibilities for the statewide support center for legal services programs in Texas assessed the effect of federal and state regulatory changes upon indigent clients. As an analyst for the Texas State Senate's Natural Resources

Committee, Mr. Johnson was responsible for research related to low-level radioactive waste disposal and low-head hydropower, and the committee's staff's interim report on energy conservation.

**AWARDS** Mr. Johnson was the recipient of the first annual Texas Outstanding Public Service Award in 1988.

**MEMBERSHIP** American Economics Association.

**TESTIMONY ON BEHALF OF TEXAS OFFICE OF PUBLIC UTILITY COUNSEL**

Docket No. 6588, Re Southwestern Bell Telephone Company,
Subject: Declassification of Documents.

Docket Nos. 7195 and 6755, Re Gulf States Utilities Company,
Subject: Rate Design/Cost Allocation.

Docket No. 7510, Re West Texas Utilities Company,
Subject: Rate Design/Cost Allocation.

Docket No. 8095, Re Texas-New Mexico Power Company,
Subject: Rate Design/Cost Allocation.

Docket No. 8363, Re El Paso Electric Company,
Subject: Rate Design/Cost Allocation.

Docket No. 8425, Re Houston Lighting & Power Company,
Subject: Revenue Requirements.

Docket No. 8425, Re Houston Lighting & Power Company,
Subject: Rate Design/Cost Allocation.

Docket No. 8646, Re Central Power and Light Company,
Subject: Revenue Requirements.

Docket No. 8646, Re Central Power and Light Company,
Subject: Rate Design/Cost Allocation.

Docket No. 8646, Re Central Power and Light Company,
Subject: Interim Rate Relief.

Docket No. 8555, Proceedings Concerning Houston Lighting & Power Company on Remand From Cause No. C-5705 and Cause No. 352,044,
Subject: Determination of Remand Amount.

Docket No. 8928, Re Texas-New Mexico Power Company,
Subject: Rate Design/Cost Allocation.

Docket No. 8585, Re Southwestern Bell Telephone Company,
Subject: Revenue Requirements/Affiliates.

Docket No. 8585, Re Southwestern Bell Telephone Company,
Subject: Reply, Revenue Requirements/Affiliates.

Docket No. 8585, <u>Re Southwestern Bell Telephone Company</u>,
Subject: Reply, Rate Design.

Docket No. 8585, <u>Southwestern Bell Telephone Company</u>,
Subject: Proposed Non-Unanimous Stipulation.

Docket No. 9300, <u>Texas Utilities Electric Company</u>,
Subject: Revenue Requirement.

Docket No. 9300, <u>Texas Utilities Electric Company</u>,
Subject: Cost Allocation and Rate Design.

Docket No. 9300, <u>Texas Utilities Electric Company</u>,
Subject: Prudence of Plant Acquisition.

Docket No. 9561, <u>Central Power and Light Company</u>,
Subject: Revenue Requirement.

Docket No. 9561, <u>Central Power and Light Company</u>,
Subject: Cost Allocation and Rate Design.

Docket No. 9578, <u>Sugar Land Telephone Company</u>,
Subject: Inquiry into Sale.

Docket No. 9850, <u>Houston Lighting & Power Company</u>,
Subject: Revenue Requirement.

Docket No. 9850, <u>Houston Lighting & Power Company</u>,
Subject: Cost Allocation and Rate Design.

Docket No. 9850, <u>Houston Lighting & Power Company</u>,
Subject: Settlement Testimony: Revenue Requirement and Rate Design.

Docket No. 9981, <u>Central Telephone Company</u>,
Subject: Revenue Requirement/Affiliates.

Docket No. 10894, <u>Gulf States Utilities Company</u>,
Subject: Affiliate Transactions/Power Purchases.

Docket No. 11735, <u>Texas Utilities Electric Company</u>,
Subject: Revenue Requirement and Rate Design.

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| Docket No. 11892, | General Counsel's Original Petition for Generic Proceeding Regarding Purchased Power, |
| Subject: | Impact of Purchased Power on Cost of Capital. |
| Docket No. 12700, | El Paso Electric Company, |
| Subject: | Acquisition, Revenue Requirement and Rate Design. |
| Docket No. 12957, | Houston Lighting & Power Company, |
| Subject: | Contract Pricing Tariff. |
| Docket No. 13100, | Texas Utilities Electric Company, |
| Subject: | Competitive Pricing Tariffs. |
| Docket No. 13575, | Texas Utilities Electric Company, |
| Subject: | Demand Side Management and Purchase Power Recovery. |
| Docket No. 12065, | Houston Lighting & Power Company, |
| Subject: | Revenue Requirement/Plant Cancellation/Prudence. |
| Docket No. 12065, | Houston Lighting & Power Company, |
| Subject: | Cost Allocation and Rate Design. |
| Docket No. 13943, | Gulf Coast Power Connect, |
| Subject: | Transmission Line CCN. |
| Docket No. 13575, | TUEC Application for Relief Regarding Recovery Solicitations, |
| Subject: | DSM and Purchase Power Cost Recovery. |
| Docket No. 13369, | West Texas Utilities Company, |
| Subject: | Cost Allocation and Rate Design. |
| Docket No. 14435, | Southwestern Electric Power Co., |
| Subject: | Rate Design. |
| Docket No. 14716, | Texas Utilities Electric Company, |
| Subject: | Wholesale Competitive Rate. |
| Docket No. 14965, | Central Power and Light Company, |
| Subject: | Cost Allocation, Rate Design and Competitive Issues. |

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| Docket No. 14965, | Central Power and Light Company, |
| Subject: | Reply, Cost Allocation, Rate Design and Competitive Issues. |
| Docket No. 15560, | Texas-New Mexico Power Company, |
| Subject: | Competitive Issues. |
| Docket No. 16705, | Entergy Gulf States, Inc., |
| Subject: | Cost Allocation, Rate Design and Competitive Issues. |
| Docket No. 16705, | Entergy Gulf States, Inc., |
| Subject: | Reply, Cost Allocation, Rate Design and Competitive Issues. |
| Docket No. 16995, | Central Southwest Corp., |
| Subject: | Integrated Resource Planning. |
| Docket No. 17751, | Texas-New Mexico Power Company, |
| Subject: | Rate Design and Competitive Issues. |
| Docket No. 18845, | CPL, WTU, and SWEPCO, |
| Subject: | Integrated Resource Planning. |
| Docket No. 21527, | TXU Financing Order, |
| Subject: | Cost Allocation. |
| Docket No. 21528, | CPL Financing Order, |
| Subject: | Cost Allocation. |
| Docket No. 21591, | Sharyland Utilities Initial Rates & Tariffs, |
| Subject: | Deferrals. |
| Docket No. 21956, | Reliant Business Separation Plan, |
| Subject: | Price to Beat and Capacity Auction. |
| Docket No. 22344, | Generic Rate Design and Customer Classification for TDUs, |
| Subject: | Rate Design. |
| Docket No. 22349, | TNMP Unbundling, |
| Subject: | Competitive Transition Charge and Revenue Requirements/Cost Allocation/Rate Design. |

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| Docket No. 22350, | <u>TXU Unbundling</u>, |
| Subject: | Competitive Transition Charge. |
| Docket No. 22351, | <u>Southwestern Public Service Company Unbundling</u>, |
| Subject: | Cost Allocation/Rate Design. |
| Docket No. 22352, | <u>Central Power & Light Company</u>, |
| Subject: | Competitive Transition Charge. |
| Docket No. 22355, | <u>Reliant Unbundling</u>, |
| Subject: | Non-Bypassable Charges and Competitive Transition Charge/Cost Allocation/Rate Design. |
| Docket No.22356, | <u>Entergy Gulf States Utilities Unbundling</u>, |
| Subject: | Revenue Requirements/Cost Allocation/Competitive Transition Charge/Settlement Rate Design. |
| Docket No. 24194, | <u>Application of TNMP to Establish Price to Beat Fuel Factor</u>, |
| Subject: | Fuel and purchased power costs. |
| Docket No. 25230, | <u>Joint Application for Approval of Stipulation Regarding TXU Electric Company Transition to Competition Issues</u>, |
| Subject: | Retail Clawback Provisions of Non-Unanimous Agreement. |
| Docket No. 25314, | <u>Application of West Texas Utilities Company and Mutual Energy WTU to Establish a Fuel Reconciliation Methodology for Southwest Power Pool (SPP) Customers</u>, |
| Subject: | Fuel Cost Method. |
| Docket No. 24336, | <u>Application of Entergy Gulf States, Inc. for Approval of Price to Beat Factor</u>, |
| Subject: | Unaccounted for Energy. |
| Docket No. 23320, | <u>Petition of ERCOT for Approval of the ERCOT Administrative Fee</u>, |
| Subject: | ERCOT Fee Structure. |
| Docket No. 26194, | <u>El Paso Electric Company Fuel Reconciliation</u>, |
| Subject: | Purchased Power and Off-System Sales. |

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| Docket No. 27576, | Application of Texas-New Mexico Power Company for Reconciliation of Fuel Costs, |
| Subject: | Fuel Reconciliation. |
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| Docket No. 28813, | Inquiry Into Rates of Cap Rock Energy, |
| Subject: | Revenue Requirements/Cost Allocation/Rate Design. |
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| Docket No. 28840, | Application of AEP Texas Central Company for Change in Rates, |
| Subject: | Cost Allocation/Rate Design/Affiliate Transactions. |
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| Docket No. 30485, | Application of CenterPoint Energy Houston Electric, LLC For A Financing Order, |
| Subject: | Transition Charge Recovery. |
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| Docket No. 30143, | Petition of El Paso Electric Company to Reconcile Fuel Costs (Initial and Rebuttal Testimonies), |
| Subject: | Fuel Reconciliation. |
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| Docket No. 30706, | Application of CenterPoint Energy Houston Electric, LLC for A Competition Transition Charge, |
| Subject: | Competitive Transition Charge Structure. |
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| Docket No. 31315, | Application of Entergy Gulf States, Inc. for Approval of Incremental Purchased Capacity Recovery Rider, |
| Subject: | Purchase Power Capacity Rates. |
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| Docket No. 31544, | Application of Entergy Gulf States, Inc. for Recovery of Transition to Competition Costs, |
| Subject: | Allocation of Transition Costs. |
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| Docket No. 31994, | Application of Texas-New Mexico Power Company's to Establish a Competition Transition Charge Pursuant to P.U.C. Subst. R. 25.263(N), |
| Subject: | Competition Transition Charge. |
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| Docket No. 32475, | Application of AEP Texas Central Company for a Financing Order, |
| Subject: | Securitization of Stranded Costs. |

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| Docket No. 32758, | Application of AEP Texas Central Company for a Competition Transition Charge Pursuant to P.U.C. Subst. R. 25.263(n), |
| Subject: | Competitive Transition Charge. |
| Docket No. 32795, | Staff's Petition to Initiate Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA § 39.253(f), |
| Subject: | Stranded Costs Allocation. |
| Docket No. 32907, | Application of Entergy Gulf States, Inc. for Determination of Hurricane Reconstruction Costs, |
| Subject: | Cost Allocation. |
| Docket No. 32766, | Application of Southwestern Public Service Company for: (1) Authority to Change Rates; (2) Reconciliation of its Fuel Costs for 2004 and 2005; (3) Authority to Revise the Semi-Annual Formulae Originally Approved in Docket No. 27751 Used to Adjust its Fuel Factors; and (4) Related Relief, |
| Subject: | Cost Allocation/Rate Design. |
| Docket No. 33586, | Application of Entergy Gulf States, Inc. for a Financing Order, |
| Subject: | Financing Order Allocation. |
| Docket No. 32710, | Application of Entergy Gulf States, Inc. for Authority to Reconcile Fuel and Purchased Power Costs, |
| Subject: | Capacity Rider Allocation. |
| Docket No. 31461, | Application of AEP Texas North Company for a Competition Transition Charge Under to Subst. R. §25.263(N), |
| Subject: | Competition Transition Charge. |
| Docket No. 32795, | Staff's Petition to Initiate a Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA § 39.253(f), |
| Subject: | Stranded Cost Allocation. |
| Docket No. 33309, | Application of AEP Texas Central Company for Authority to Change Rates, |
| Subject: | Rate Design and Energy Efficiency Costs. |

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| Docket No. 33310, | Application of AEP Texas North Company for Authority to Change Rates, |
| Subject | Energy Efficiency Costs and Riders. |
| | |
| Docket No. 32902, | CenterPoint Energy Houston Electric, LLC Compliance Tariff, |
| Subject: | Allocation of Stranded Costs. |
| | |
| Docket No. 34077, | Joint Report and Application of Oncor and EFH Pursuant to § 14.101, |
| Subject: | Leveraged buyout of utility. |
| | |
| Docket No. 35105, | Compliance Tariff Filing of AEP Texas, |
| Subject: | Allocation of Stranded Costs. |
| | |
| Docket No. 35038, | Texas-New Mexico Power Company Tariff Filing in Compliance with the Final Order in Docket No. 33106, |
| Subject: | Allocation of Stranded Costs. |
| | |
| Docket No. 34800, | Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs, |
| Subject: | Cost Allocation & Rate Design. |
| | |
| *Docket No. 37482, | Application of Entergy Texas for a PCRF, |
| Subject: | Purchase Power. |
| | |
| *Docket No. 37744, | Application of Entergy Texas, Inc. for Authority to Change Rates, |
| Subject: | Cost allocation, rate design, proposed riders, & storm damage expense. |
| | |
| *Docket No. 38951, | Application of Entergy Texas, Inc. for Approval of CGS Tariff, |
| Subject: | Rate Design, Competitive Tariffs |
| | |
| *Docket No. 42454, | Application of SPS for Revision of EECRF[1] |
| Subject: | Recovery of energy efficiency costs |

[1] Asterick (*) denotes testimony for Texas OPC as a consultant.

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| **TESTIMONY ON BEHALF OF STEERING COMMITTEE OF ONCOR CITIES** | Docket No. 35634, | Re Oncor Electric Delivery's Request for an Energy Efficiency Cost Recovery Factor, |
| | Subject: | Energy Efficiency Cost Recovery. |
| | Docket No. 36958, | Application of Oncor Electric Delivery Company LLC for 2010 Energy Efficiency Cost Recovery Factor, |
| | Subject: | Energy Efficiency Cost Recovery. |
| | Docket No. 39375, | Application of Oncor Electric Delivery Company LLC for 2012 EECRF, |
| | Subject: | Energy Efficiency Cost Recovery. |
| **TESTIMONY ON BEHALF OF ALLIANCE OF XCEL MUNICI-PALITIES** | Docket No. 35664, | Application of SPS to Revise Interruptible Credit Option Tariff, |
| | Subject: | Interruptible Rate Avoided Costs. |
| | Docket No. 35763, | Application of SPS to Change Rates and Reconcile Fuel and Purchased Power Costs, |
| | Subject: | Energy Efficiency, Renewable Energy Credits, Power Cost Credits, and Interruptible Credits. |
| | Docket No. 37173, | Petition for Declaratory Order of Southwestern Public Service Company Regarding the Generation Demand Charge as a Cap on Compensation for Interruptible Resources |
| | Subject: | Interruptible Curtailable Option ("ICO"). |
| Docket No. 43695, | | Application of SPS to Change Base Rates. |
| | Subject: | Cost Allocation / Rate Design/ Jurisdictional |
| **TESTIMONY ON BEHALF OF CERTAIN TNMP CITIES** | Docket No. 36025, | Application of TNMP for Authority to Change Rates, |
| | Subject: | Cost Allocation and Rate Design. |
| | Docket No. 39362, | Application of TNMP for 2012 EECRF |
| | Subject: | Energy Efficiency Cost Recovery |

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| **TESTIMONY ON BEHALF OF PENNYSLVANIA OFFICE OF CONSUMER ADVOCATE** | Docket No. R-2010-2161575, et. al.,<br>Subject: | PECO Energy Co.-Electric Division Base Rate Case,<br>Cost Allocation and Rate Design. |
| | Docket No. R-2010-2179522,<br>Subject: | Duquesne Light Company Base Rate Case,<br>Cost Allocation and Rate Design. |
| | Docket No. R-2014-248745,<br>Subject: | Met Edison General Base Rate Case,<br>Cost Allocation and Rate Design. |
| | Docket No. R-2014-2478743,<br>Subject: | Penelec Power General Base Rate Case,<br>Cost Allocation and Rate Design. |
| | Docket No. R-2014-2478744,<br>Subject: | Penn Power General Base Rate Case,<br>Cost Allocation and Rate Design. |
| | Docket No. R-2014-248752,<br>Subject: | West Penn Power General Base Rate Case,<br>Cost Allocation and Rate Design. |
| **TESTIMONY ON BEHALF OF BEHALF OF GULF COAST COALITION OF CITIES** | Docket No. 38339,<br>Subject: | Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates,<br>Cost Allocation, Rate Design, Riders. |
| **TESTIMONY ON BEHALF OF SWEPCO CITIES** | Docket No. 40443,<br>Subject: | Application of SWEPCO for Rate Change.<br>Cost Allocation, Rate Design, Fuel Rule, Revs. |
| **TESTIMONY ON BEHALF OF ST.LAWRENCE COTTON GROWERS** | Docket No. 41474,<br>Subject: | Application of Sharyland Utilities for Unbundled Delivery Rates.<br>Cost Allocation, Rate Design, Unbundling. |

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| **TESTIMONY ON BEHALF OF LIVE OAK TENANTS** | Docket No.41987 | <u>Complaint Against Live Oak Resort</u> |
| | Subject: | Sub Metering Complaint Case |
| **TESTIMONY FOR CONNECTICUT CONSUMER COUNSEL** | Docket No.14-05-06 | <u>CL&P Rate Increase Application</u> |
| | Subject: | Cost Allocation, Rate Design, Decoupling |
| **TESTIMONY FOR TEXAS COAST UTILITIES COALITION** | Docket No.44572 | <u>Centerpoint Application for DCRF</u> |
| | Subject: | Distribution Cost Recovery Factor |
| **TESTIMONY FOR CITY OF EL PASO** | Docket No.44941 | <u>El Paso Electric Rate Case</u> |
| | Subject: | Class Cost Allocation; Rate Design |

# Non Nuclear Decommissioning ($/kW)

| | AE | PUC Approved | Difference | Percent |
|---|---|---|---|---|
| **Decker** | 38 | 17 | 21 | 55.3% |
| **FPP** | 50 | 39 | 11 | 22.0% |
| **Sand Hill** | 39 | 20 | 19 | 48.7% |

| | Requested Expense | Reduction | Allowed |
|---|---|---|---|
| **Decker** | $ 14,000,000 | $ 7,736,842 | $ 6,263,158 |
| **FPP** | $ 3,750,000 | $ 825,000 | $ 2,925,000 |
| **Sand Hill** | $ 1,692,308 | $ 824,458 | $ 867,850 |
| **Total** | $ 19,442,308 | $ 9,386,300 | $ 10,056,008 |

## Production Demand Allocation Factors

| | Residential | S1 | S2 | S3 | P1 | P2 | P3 |
|---|---|---|---|---|---|---|---|
| **BIP-N** | 35.990% | 2.012% | 21.459% | 20.223% | 4.060% | 4.794% | 9.375% |
| **BIP-R** | 35.351% | 2.027% | 21.449% | 20.393% | 4.090% | 4.927% | 9.601% |
| **Adj. A&P-12CP** | 35.312% | 2.041% | 21.451% | 20.409% | 4.069% | 4.939% | 9.610% |

| | T1 | T2 | Street L. | Outdoor L. | Cust. L. | Meter L. | Total |
|---|---|---|---|---|---|---|---|
| **BIP-N** | 0.138% | 1.623% | 0.220% | 0.077% | 0.011% | 0.019% | 100% |
| **BIP-R** | 0.150% | 1.659% | 0.239% | 0.083% | 0.012% | 0.020% | 100% |
| **Adj. A&P-12CP** | 0.152% | 1.658% | 0.243% | 0.084% | 0.012% | 0.020% | 100% |

## Filed Rev Requirement With ICA Allocation Changes

*Revenues Include Test Year Pass Throughs*

| | Total Retail | Residential | S1 | S2 | S3 | P1 | P2 | P3 |
|---|---|---|---|---|---|---|---|---|
| **Rate Revenue** | 1,234,701,609 | 474,062,283 | 31,458,282 | 283,339,669 | 238,491,828 | 46,257,714 | 52,185,478 | 89,945,727 |
| **Cost of Service** | 1,217,227,310 | 473,181,804 | 31,155,368 | 248,378,108 | 236,751,405 | 46,347,384 | 54,007,094 | 99,546,767 |
| **Difference** | (17,474,299) | (880,479) | (302,914) | (34,961,561) | (1,740,423) | 89,670 | 1,821,616 | 9,601,040 |
| **Req Incr (Decr)** | -1.4% | -0.2% | -1.0% | -12.3% | -0.7% | 0.2% | 3.5% | 10.7% |

| | T1 | T2 | Street L. | Outdoor L. | Cust. L. | Meter L. | Total |
|---|---|---|---|---|---|---|---|
| **Rate Revenue** | 2,146,390 | 13,517,421 | - | 2,884,834 | 108,555 | 303,428 | 1,234,701,609 |
| **Cost of Service** | 1,777,803 | 15,902,764 | - | 4,046,522 | 141,145 | 380,977 | 1,211,617,140 |
| **Difference** | (368,587) | 2,385,343 | - | 1,161,688 | 32,590 | 77,549 | (23,084,468) |
| **Req Incr (Decr)** | -17.2% | 17.6% | | 40.3% | 30.0% | 25.6% | -1.9% |

## Base Revenue CCOS Results With ICA Recommendation

| | Total Retail | Residential | S1 | S2 | S3 | P1 | P2 | P3 |
|---|---|---|---|---|---|---|---|---|
| **Base Revenue** | 631,878,463 | 257,323,175 | 19,088,191 | 155,631,706 | 116,217,584 | 19,269,437 | 22,527,463 | 33,982,914 |
| **Cost of Service** | $ 592,954,232 | $ 246,920,129 | $ 18,430,624 | $ 116,730,202 | $ 110,534,601 | $ 18,568,026 | $ 23,360,161 | $ 41,699,958 |
| **Difference** | $ (38,924,231) | $ (10,403,046) | $ (657,567) | $ (38,901,504) | $ (5,682,983) | $ (701,411) | $ 832,698 | $ 7,717,044 |
| **Req Incr (Decr)** | -6.2% | -4.0% | -3.4% | -25.0% | -4.9% | -3.6% | 3.7% | 22.7% |

| | T1 | T2 | Street L. | Outdoor L. | Cust. L. | Meter L. |
|---|---|---|---|---|---|---|
| **Rate Revenue** | 1,328,468 | 3,970,086 | - | 2,316,693 | 44,617 | 178,130 |
| **Cost of Service** | $ 919,567 | $ 6,050,959 | $ - | $ 3,454,599 | $ 74,193 | $ 251,158 |
| **Difference** | $ (408,901) | $ 2,080,873 | $ - | $ 1,137,907 | $ 29,576 | $ 73,028 |
| **Req Incr (Decr)** | -30.8% | 52.4% | | 49.1% | 66.3% | 41.0% |

## Modifications to AE CCOS Model

| Sheet | Column | Row | Subject | |
|---|---|---|---|---|
| WP D-1 | O | 144 | reduce uncollectibles | |
| WP D-1 | O | 17 | reduce decommissioning | |
| WP D-1 | O | 27 | revenue imputation | (a) |
| WP D-2 | K | 8 | A&G 920 allocation | |
| WP E-4 | I | 11 | functionalize 311 expense | |
| WP E-5.1 | I | 55 | functionalize service connect. revenues | |
| Sch. F-6 | B thru Q | 58 - 63 | Insert new class allocators | |
| Sch. G-2 | F | 27 | revenue imputation | (a) |
| Sch. G-4 | F | 184 | sub functionalize 311 expense | |
| Sch.G-4 | F | 696 | sub functionalize A920 | |
| Sch.G-6 | G | 15 | revenue imputation | (a) |
| Sch. G-6 | G | 9 thru 14 | BIP allocation | |
| Sch. G-6 | G | 46 - 49 | Distribution allocation | |
| Sch. G-6 | G | 54 | Meter allocation | |
| Sch. G-6 | G | 64 - 67 | Customer allocation | |

*(a) The AE model provided no revenue imputation lines. The revenue imputation was reflected as a negative expense based on an unused expense account.*

## ICA Proposed Distribution of Revenue Decrease

| | Total Retail | Residential | S1 | S2 | S3 | P1 | P2 |
|---|---|---|---|---|---|---|---|
| **Base Revenue** | 631,878,463 | 257,323,175 | 19,088,191 | 155,631,706 | 116,217,584 | 19,269,437 | 22,527,463 |
| **kWh Percent** | 100% | 34% | 2% | 22% | 21% | 4% | 5% |
| **Rev Decrease** | $ (41,865,171) | $ (14,402,942) | $ (868,906) | $ (9,164,027) | $ (8,913,512) | $ (1,814,877) | $ (2,253,556) |
| | -6.6% | -5.6% | -4.6% | -5.9% | -7.7% | -9.4% | -10.0% |

| | P3 | T1 |
|---|---|---|
| **Base Revenue** | 33,982,914 | 1,328,468 |
| **kWh Percent** | 10% | 0.2% |
| **Rev Decrease** | $ (4,371,373) | $ (75,977) |
| | -12.9% | -5.7% |

*Notes:*
*Assumes $2.08 Mil rev increase for T2 for calculation purposes.*
*No rate change for lighting classes.*

## ICA Residential Customer Charge Calculation

| | | |
|---|---|---|
| Meters | $ | 13,569,411 |
| Customer Accounting | $ | 24,600,367 |
| Customer Service | $ | 9,572,309 |
| Meter Reading | $ | 14,741,815 |
| Uncollectible | $ | - |
| Key Accounts | $ | 12,461 |
| Services | $ | (195,771) |
| Exclude GFT from Exp. | $ | (6,849,773) |
| Exclude A&G Expense | $ | (12,202,382) |
| | | |
| Total | $ | 43,248,437 |
| Residential Bills | | 4,626,216 |
| | $ | 9.35 |