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

POST-HEARING BRIEF OF THE

INDEPENDENT CONSUMER ADVOCATE

JUNE 10, 2016

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

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TABLE OF CONTENTS

I. INTRODUCTION

The City of Austin retained an Independent Consumer Advocate ("ICA"), for the purpose of representing the interests of residential, small commercial, and House of Worship customers during the 2016 electric rate review of Austin Energy ("AE" or "Utility"). In February 2016, the Austin City Council selected John B. Coffman LLC to serve as the Independent Consumer Advocate during this rate review proceeding. The ICA team includes Mr. John B. Coffman, Ms. Janee Briesmeister, and Mr. Clarence L. Johnson, who served as the ICA's testifying expert witness during the hearing held in this matter before the Impartial Hearing Examiner ("IHE"). Mr. Johnson has 33 years of experience as a professional regulatory analyst for Texas Office of Public Utility Counsel ("OPUC") and as an independent expert witness, appearing in over 100 proceedings before the Public Utility Commission of Texas ("PUC" or "Commission") and other utility regulatory agencies.[1]

In pursuit of its mission, the ICA independently reviewed and analyzed Austin Energy's entire proposal to change electric rates on behalf of the best interests of a majority of residential, small commercial, and House of Worship customers. The ICA conducted discovery, filed written testimony, and fully participated in the evidentiary hearing on May 31 through June 2, 2016. The ICA was guided by the 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

[1] Exhibit ICA-1, pp. 5-6 and Attachment A.

customer classes.[2] The ICA was also guided by the affordability goals adopted by the Austin City Council in February 2014.[3]

The ICA sponsored several adjustments to AE's proposed overall base revenue requirement, and is adopting other adjustments, which combined would reduce the total annual revenue required of AE's customers by $63,216,000[4], more than twice the base rate revenue reduction of $24.5 million proposed by AE[5]. These adjustments are detailed in Section II of this Post-Hearing Brief.

The ICA also analyzed Austin Energy's class cost of service study (CCOS) and the CCOS performed by some large commercial customer intervenors, as well as performing its own CCOS proposal. The ICA's proposed CCOS for allocating costs among customer classes revenues is explained in detail in Section III of this Post-Hearing Brief.

Although Austin Energy is recommending a $24.5 million annual revenue reduction, the utility is proposing that none of this excess revenue be applied to decrease the electric rates of residential and small commercial customer classes. Rather Austin Energy recommends that any decrease be applied to its larger commercial customers, which it claims are paying above the cost to serve those customers. In fact, Austin Energy's new updated rate review position would result in a shift of approximately $18.4 million in additional rate responsibility onto residential

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[2] Exhibit AE-1, Tariff Package, p. 037; Appendix B.

[3] Exhibit AE-1, Tariff Package, Appendix F, p. 374.

[4] Sum of ICA's total post-hearing revenue reduction recommendations contained in Section II of this brief.

[5] Exhibit AE-2, Dombroski Rebuttal Testimony, p. 9.

customers.[6] 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.[7]

The ICA's own class cost of service study (CCOS) produced very different results than the utility's study regarding the relative cost positions for the classes, showing that the current base revenues for residential and small commercial customer classes are at or above the cost to service those classes. Therefore, the ICA is recommending that a greater number of customers share in the ultimate overall revenue requirement reduction resulting from this proceeding, including a significant electric base rate reduction for residential consumers, as explained in more detail in Section IV of this Post-Hearing Brief.

As a compromise allocation, the ICA recommends that the revenue requirement decrease be distributed among the various customer classes on the basis of *class shares of kilowatt hour ("kWh") consumption*, producing these percentage reductions per customer class:

Residential	**-5.5%**
Small Secondary	**-4.5%**
Medium Secondary	**-5.8%**
Large Secondary	**-7.5%**
Primary Classes	**-9.2% to -12.6%**
Transmission (non-contract)	**-5.6%[8]**

The relative rate reductions shown above are based upon the ICA's direct testimony position supporting an annual revenue requirement reduction of approximately $41 million. Based on a review of the record, including other parties' recommendations, ICA's updated post-hearing

6 Exhibit ICA-35.

7 Exhibit AE-1, Tariff Package, p. 025.

8 Source: Exhibit ICA-1, Schedule CJ-6.

recommendation is a $63,216,000 annual revenue reduction, an amount which would result in larger percentage reductions to each customer class:

Residential	**-8.7%**
Small Secondary	**-7.1%**
Medium Secondary	**-9.2%**
Large Secondary	**-11.9%**
Primary Classes	**-14.7% to -20.0%**
Transmission (non-contract)	**-8.9%**

Regardless of the annual revenue reduction that is adopted by the IHE, or ultimately by the City Council, the ICA recommends that the same allocation method (based upon class shares of kWh consumption) be applied to distribute the adopted level of revenue reduction among the customer classes.

In its rebuttal testimony, Austin Energy also proposed a dramatic re-allocation of the rate recovery for the Energy Efficiency Services ("EES") Charge, which would nearly double the EES rate that is currently charged to residential customers.[9] The ICA is opposed to this proposal, as is discussed in Subsection III.F. of this Post-Hearing Brief. Because of the timing of this proposal, the ICA was procedurally unable to analyze this late-filed change or to respond to it in its written testimony. If this new proposal is adopted, the resulting rate impact on AE's proposed class revenue shifts would be great enough to ensure that almost all residential customers would receive a rate *increase* from this rate review proceeding.[10] Residential customers would receive a net increase in rates at the very same time that AE proposes to decrease its overall system revenues and provide rate reductions to its largest commercial customers. AE did not include

[9] Exhibit AE-7, Kimberly Rebuttal Testimony, pp. 15-16.

[10] Exhibit ICA-34; Exhibit ICA-26; Tr. 1082-1090 (Dreyfus).

this EES re-allocation in its CCOS analysis, and further acknowledged at the hearing that the EES re-allocation proposal was "not fully vetted".[11]

With regard to Rate Design for the various rates within the Residential, Small Commercial, and Houses of Worship customer classes, the ICA makes several recommendations, which are contained in Section IV of this Post-Hearing Brief.

Section VI of this Post-Hearing Brief contains additional ICA recommendations addressing certain Austin Energy policies and programs.

II. REVENUE REQUIREMENT

Austin Energy's current base rate revenue requirement is $614.4 million, which does not include the projected costs for the three pass-through charges (Power Supply Adjustment, Regulatory Charge, and Community Benefits Charge). AE's updated rate review proposal states that its current base rate structure is currently collecting approximately $24.5 million more than the revenue required to meet its test year 2014 costs, which represents excess revenue that should be returned to customers through reduced rates going forward.[12]

The ICA believes that a greater reduction to base rates is necessary to ensure a just and reasonable rate level. The following ICA adjustments to AE's base revenue requirement would further reduce the total annual revenue required of AE's customers by $38,716,000, for a total recommended revenue requirement reduction of $63,216,000.

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[11] Tr. 1006, ln.15-23 (Maenius).

[12] Exhibit AE-1, Tariff Package, p. 021, Footnote 11; updated in Exhibit AE-2, pp. 7-10.

A. Residential Base Revenue Customer Assistance Program Adjustment

Austin Energy adopted this adjustment in its written rebuttal testimony.[13] The ICA supports this adjustment, which recognizes the revenues supplied by the Customer Assistance Program ("CAP") charge, and positively impacts class cost of service results for the residential class. Since only residential customers receive the low income CAP discount, the additional revenues which fund the discount, as reflected in this adjustment, only affect the residential class.[14] Yet AE's proposed distribution of the revenue reduction apparently would use this adjustment to fund revenue reductions for other classes.[15] The ICA disagrees with this element of AE's proposal and would use the revenues provided by this adjustment to fund a reduction for *all* classes, based upon ICA's proposed revenue allocation.

B. Decommissioning Funding

ICA recommends a $9.89 million reduction to AE's proposed annual non-nuclear decommissioning funding. Austin Energy has a non-nuclear commissioning fund expense for which it attempts to estimate the future cost of decommissioning a fossil fuel generating plants at 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.[16] In this fashion, the depreciation rates cover the cost of decommissioning over the life of the power plant. However,

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[13] Exhibit AE-2, Dombroski Rebuttal Testimony, pp. 9-10.

[14] Exhibit ICA-30.

[15] Dombroski Rebuttal Testimony at 10, l. 14-16.

[16] Direct Testimony of Clarence Johnson, Exhibit ICA-1, p. 17.

AE has not included net salvage value in the depreciation rates it recovers.[17] 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.[18]

The ICA believes that AE's requested decommissioning amount is excessive. AE is recovering the expense over a truncated period, rather than the normal life of plant recovery.[19] This results in a "lumpy" payment and is not consistent with intergenerational equity, inasmuch as the total expense will be unfairly paid by consumers at the tail end of the plant's life, rather than over the life of the asset.

The evidence indicates that AE's 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 costs are 20% - 50% or more than the average Texas PUC approved decommissioning cost.[20] The evidence of over-estimation is supported by the tables in AE's NewGen study, which show that AE's indicated decommissioning costs are higher than both the average PUC *approved* amounts and the utility average *requested*

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[17] Direct Testimony of Clarence Johnson, Exhibit ICA-1, p. 18.

[18] Exhibit AE-1, WP/ D-1.2.5.

[19] Exhibit ICA-1, p. 18.

[20] Exhibit ICA-1, p. 18.

amounts.[21] Second, the decommissioning cost estimates contain no offsets for the value of water rights or potential sale of land. The study did not adequately consider these potential offsetting benefits associated with decommissioning.[22] Third, the study gave no offsetting value to selling working components because this was considered "too uncertain."[23] 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.[24] The scope and tasks for nuclear facilities are much more uncertain than for fossil plants.[25] Although AE's rebuttal testimony attempts to paint the 10.7% contingency for Decker as coincidently "supported" by the PUC's nuclear decommissioning rule, the testimony fails to recognize that Decker's decommissioning costs do not include the uncertainty and risk associated with decontaminating radioactive plant structures. A 10% contingency for nuclear plants implies that the equivalent adder for fossil plants should be much smaller. Fifth, the contingency adders for decommissioning the Sand Hill and Fayette plants 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.[26] This is an inconsistency that unfairly raises the estimates for which current electric consumers are being asked to pay.

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[21] Exhibit ICA-1, pp. 18-19.

[22] Exhibit ICA-1, p. 19, citing AE Answer to ICA 4-6 (e) (f).

[23] Exhibit ICA-1, p. 19, citing AE Response to ICA 4-6 (d).

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

[25] Exhibit ICA-1, p. 19.

[26] Exhibit ICA-1, p. 19.

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.[27] This implies that depreciation must recover 2% above gross plant cost to cover decommissioning. By comparison, AE's proposed decommissioning cost for the Decker plant is almost one-half of the plant's original gross cost.[28]

Therefore, the ICA recommends that AE's proposed annual decommissioning expense allowance be reduced by 48%, based on the average decommissioning cost per kW approved by PUCs for the applicable type of generation plant, as set out in Table 4 of the NewGen study,[29] resulting in a $9.89 million revenue requirement reduction.[30] The details for this adjustment can be found in Schedule CJ-1 to the direct testimony of ICA witness Clarence Johnson.[31] Given that AE's estimates are near the upper boundary of decommissioning costs, the ICA's recommended approach balances AE's interest in in providing an adequate amount of future decommissioning funds with the consumers' interest in containing costs recoverable through rates, while mitigating intergenerational inequity.[32]

AE witness Mr. Dombroski rebuts the proposals of other parties (Seton, AELIC, and NXP/Samsung) to treat AE's decommissioning expense in a manner other than as an operating expense, and notes that the ICA agrees with AE's approach of utilizing a decommissioning

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

[28] Exhibit ICA-1, p. 19.

[29] Appendix I to the NewGen study, page 99.

[30] Exhibit ICA-1, p. 20.

[31] Exhibit ICA-1, Schedule CJ-1.

[32] Exhibit ICA-1, p. 20.

fund.[33] And although Mr. Dombroski acknowledges that the ICA is recommending a lower level of annual recovery for this expense, his testimony does not contest the reasonableness of the ICA's recommended level of decommissioning expense. Although AE witness Mr. Mancinelli argues that the NewGen estimate for Decker is site-specific, he never explains why such an estimate is significantly higher than the average cost of decommissioning similar power plant approved by Public Utility Commissions across the country.[34] AE's evidence simply does not meet the burden of proof necessary to support its proposal on this issue. The weight of the evidence in the record of this rate review proceeding supports the ICA position for non-nuclear decommissioning expense.

C. Internally Generated Funds for Construction

ICA supports, in part, the adjustment made by NXP/Samsung to AE's proposal for an allowance for "internally generated funds for construction". NXP/Samsung witness Ms. Fox proposes an adjustment in her corrected direct testimony to exclude test year internally-generated production construction expenses from AE's calculation of revenue requirement, reducing AE's request of $158,169,688 down to $120,000,000 for total expenditures.[35] She also recommends that 40% of that total be funded with cash, which she believes represents the average amount that AE has utilized on construction expenses between FY2012 and FY2015, which would be a decrease of approximately $38.3 million from AE's request of $88.3 million for cash to transfer to the CIP fund.[36]

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33 Exhibit EA-2 (Dombroski Rebuttal), pp. 9-10.

34 Exhibit EA-3, pp. 13-15.

35 Exhibit NS-1, pp. 17-22.

36 Exhibit NS-1, p. 19.

The ICA agrees that a normalization of these annual construction expenditures is appropriate, but offers a compromise position. AE rebuttal witness Mr. Dombroski testifies that the average annual construction improvement plan ("CIP") for existing production plant has been $21 million since FY2012.[37] Although this is lower than AE's requested CIP for production plant, he did not identify any specific or extraordinary construction projects which would justify a departure from a normalized amount.[38] Adding the average of $21 million in construction expenditures for existing production plant to Ms. Fox's normalized non-production construction expenditures results in $146 million for the CIP. Based on the internally generated cash formula on page 18 of Mr. Dombroski's testimony, this adjustment supports a revenue requirement reduction of $6 million.[39] Therefore, the ICA supports a compromise adjustment to the AE position on internally generated funds for construction, thereby reducing AE's annual cash requirement by $6 million.

D. Transmission Costs and Revenues

The ICA takes no position on this issue at this time.

[37] Dombroski Rebuttal at 19.

[38] Exhibit AE-2, p. 18.

[39] Mr. Dombroski shows $88 million for internal cash generation requirement as the result of the formula, and with the $146 million CIP, the result changes to $82 million in necessary cash generation.

E. FPP Debt Defeasement

ICA concurs with the rebuttal testimony of AELIC[40] and Austin Energy[41] in opposing PCSC's proposed $31.5 million annual revenue requirement increase[42] to fund a defeasement reserve for the Fayette Power Project ("FPP").

Public Citizen/Sierra Club ("PCSC") states that if the FPP is retired by the end of 2023, the debt associated with that plant would need to be retired early, and so they recommend a bond retirement reserve fund be established and funded for the period of 2017-2022. PCSC bases their position on a 2014 presentation by AE which assumes an outstanding debt of $189 million associated with the FPP, and then they divide $189 million by six years, arriving at an annual debt retirement reserve of $31.5 million.[43] However, for several reasons, this proposal is not necessary nor reasonable.

The City Council has not yet approved a date for retirement of the FPP, and cannot do so without the joint owner, the Lower Colorado River Authority, and closing that plant prematurely could expose AE to reliability risks and volatile wholesale market prices.[44] Moreover, defeasement of bond debt prior to the date the debt actually becomes callable could expose AE to legal risks.[45]

According to evidence adduced by AELIC, the outstanding debt associated with the FPP is actually $168.8 million and a significant amount of that debt is likely to be retired through

40 Exhibit ALIEC-3, Testimony of Carol A. Szerszen, pp. 2-7.

41 Exhibit AE-2, Dombroski Rebuttal Testimony, pp. 22-23.

42 PCSC Corrected Position Statement, Issue #4, pp. 22-23.

43 PCSC Corrected Position Statement, p. 23.

44 Exhibit AE-2, Dombroski Rebuttal Testimony, pp. 22-23.

45 Exhibit AE-2, Dombroski Rebuttal Testimony, pp 23.

sinking funds payments over the next few years.[46] Series 2007 revenue bonds will be paid off by 2020, and AE could assign 2016-2025 sinking fund amounts from its series 2008 and 2010A revenue bonds to the FPP, minimizing the impact that any early retirement of the plant would have on ratepayers.[47] Furthermore, AE includes the FPP in the development of a non-nuclear decommissioning fund as part of its rate filing (as discussed in Section II.B. above), and that expense may serve a functionally equivalent goal to the goal of creating a reserve fund.[48] Moreover, rate making practice provides for amortization of undepreciated plant costs, to the extent it exists at the time of a plant's retirement, which would contribute to the payment of any remaining debt.[49] As pointed out by ICA witness Mr. Johnson, it is premature to determine either the exact retirement date, the debt defeasement cost, or how much of the cost can be paid by new debt issuances rather than by immediate cash.[50]

The ICA does not believe that it is appropriate to consider increasing electric rates to create an unnecessary reserve fund while Austin Energy continues to struggle with meeting the affordability and competitiveness goals set forth by the City Council.[51] When the affordability of electric rates is considered, as well as other risk factors that would be involved with early retirement of FPP debt, the ICA believes that this particular PCSC proposal should be rejected.

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[46] Exhibit ALIEC-3, Testimony of Carol A. Szerszen, pp. 2-4.

[47] Exhibit ALIEC-3, Testimony of Carol A. Szerszen, pp. 5-6.

[48] Exhibit ICA-2, Johnson Cross-Rebuttal Testimony, p. 20.

[49] Exhibit ICA-2, Johnson Cross-Rebuttal Testimony, pp. 18-20.

[50] Id.

[51] Exhibit ICA-2, Johnson Cross-Rebuttal Testimony, pp. 18-20, citing to the Austin Energy Resource and Generation and Climate Protection Plan to 2025 (December 2014).

F. Debt Service Associated with South Texas Nuclear Project

The ICA takes no position on this issue at this time.

G. Uncollectible Expense Allowance (Account 904)

ICA recommends an adjustment to the uncollectible expense allowance, reducing AE proposed revenue requirement by $5.855 million.[52] AE's proposed uncollectible expense in Account 904 was based upon a FY2014 level of $20.86 million and adjusts this amount to a test year level of $16.1 million,[53] although AE's 2015 uncollectible expense appears to have dropped dramatically to almost half of that amount. AE's proposed level for uncollectible expense is high by almost any standard.

Uncollectible expense reflects bad debt cost. 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. On an annual basis, the amount of bad debt expense for the utility 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, the ICA is recommending a normalization of the uncollectible amount based upon historic uncollectible experience.[54] 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, ICA witness Mr. Johnson shows historic uncollectible amounts as a ratio of AE's

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52 Exhibit ICA-1, p. 16.

53 Exhibit AE-1, WP-D-1.2.9.

54 Exhibit ICA-1, pp. 12-17.

electric revenues in this table from page 13 of his direct testimony[55], from which he calculates the average uncollectible rate over the previous five years and the previous 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%
Average Rate (7yr)			0.6770%
Average Rate (5yr)			0.8379%

As shown above, AE's historical uncollectible rate was relatively stable until 2013 and 2014, when the uncollectible amount more than quintupled for those two years. The shorter five-year normalization period produces the larger amount than the seven-year, because the 2013 and 2014 uncollectible amounts comprise a greater proportion of the average. The range is from $8.2 million to $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.[56]

[55] Exhibit ICA-1, p. 13.

[56] Exhibit ICA-1, pp. 13-14.

According to ICA witness Mr. Johnson, a 2014 increase of more than five-fold in an historically stable expense is almost certainly associated an extraordinary event. The evidence shows that Austin Energy incurred widespread problems in the implementation of a new IBM billing system during the 2011 – 2013 timeframe.[57] Austin Energy documented numerous complaints about the vendor's inadequacies, and the billing issues garnered national attention.[58] More than 100,000 customers were affected by billing system errors in 2011 - 2012.[59] 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.[60] As a result, substantial debt accumulated, with many customers accruing thousands of dollars of past due bills.

Because the lack of bills and billing errors contributed to the amounts owed by customers, the City Council liberalized the deferred payment procedures. Although the billing 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

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[57] Exhibit ICA-1, p. 14.

[58] *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

[59] *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/

[60] *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/

treated as a recurring event. Therefore, normalizing the expense amount based on average historical experience is appropriate.[61] In fact, in a June 23, 2014 presentation, AE identified four contributors to its recently high uncollectible experience, and AE acknowledged at the hearing that at least three of those contributing causes have ended.[62] The AE presentation also projected that going forward uncollectible expense would be trending downward.[63]

Further illustrating the unreasonably high level of AE's proposed uncollectible expense, 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.

		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

61 Exhibit ICA-1, p. 15.

62 Tr. p. 649 (Dombroski). Exhibit AELIC-38

63 Tr. p. 649.

The three bundled investor-owned utilities are Southwestern Public Service Co. (SPS), Entergy Texas Inc. (ETI), and El Paso Electric Co. (EPE). As can be seen here, Austin Energy's requested uncollectible expense per customer is more than three times the other utilities' uncollectible request.[64]

The ICA recommends using the upper end of the range (5-year average) of normalized uncollectible expense experienced by Austin Energy. This amount is $10,199,660.[65] After known and measurable adjustment, Austin Energy utilized a test year amount of $16,054,751. Therefore, the ICA proposed expense reduction is $5.855 million.[66]

The test year amount for uncollectible expense should be representative of future costs. Given the large fluctuation in bad debt 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 was 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.[67]

The ICA adjustment on this issue is very conservative, because even with the proposed reduction in the allowance for bad debt, the adjusted amount remains quite high. Even with the disallowance, the uncollectible expense per customer would still be $23.35—more than twice the uncollectible per customer cost of SPS, the highest cost investor-owned utility in the table

[64] Exhibit ICA-1, pp. 15-16.

[65] Exhibit ICA-1, p. 16.

[66] Exhibit ICA-1, p. 16.

[67] *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.

presented above.[68] If the adjustment had been based on a longer period for normalization, the reduction would be larger too. 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. Austin Energy should be able to manage this expense to a more reasonable level, well below what the ICA recommended allowance will provide.

H. Economic Development and Community Programs

ICA recommends bringing greater transparency to Austin Energy's transfers to the Economic Development Department and its donations and contributions to Community Programs by including them in the General Fund transfer. In this manner, the economic development expenditures and donations would be clearly segregated from utility expenditures. These expenditures would still be recovered, but apart from those expenditures that are essential to the cost of providing of safe and reliable electric service.

Like other city departments, Austin Energy contributes to the City's economic development efforts. $9,090,429 is currently collected through the customer charge.[69] 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.[70]

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[68] Exhibit ICA-1, p. 17.

[69] Exhibit AE-1, Cost of Service Model Schedule H-5.4.

[70] Exhibit ICA-1, p. 27.

AE witness Mr. Dombroski argues that economic development efforts benefit the utility by developing a "more diverse system load".[71] NXP/Samsung questioned this notion, stating that economic growth activities benefit the community, but that these expenditures "have little to no association with the provision of electric service".[72] NXP/Samsung further suggested that using ratepayers funds to encourage growth and energy consumption is not consistent with also charging consumers for programs to encourage a reduction in energy consumption.[73] NXP/Samsung also pointed out that the City Council has initiated a transition plan to allocate economic development funding to the General Fund of other City departments, but that the amount of the transition will not be known until the City Council approves the 2016-2017 budget.[74]

NXP/Samsung recommends that economic development programs not be included at all as an AE expense, unless AE can substantiate benefits to utility ratepayers.[75] ICA, however, is not requesting a disallowance; rather it is recommending that these funds be treated as flowing through the General Fund Transfer ("GFT"), as thus part of discretionary funds to the City.[76]

On the witness stand, AE witness Mr. Dombroski supported the treatment of the donations that it makes to Community Programs as "appropriate community expenditures of Austin Energy", even while acknowledging that those donations are "not explicitly to provide for

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[71] Exhibit AE-2, p. 27.

[72] Exhibit NS-1, p. 30.

[73] Exhibit NS-1, p. 30.

[74] Exhibit NS-1, p. 30.

[75] Exhibit NS-1, p. 31.

[76] Exhibit ICA-1, p. 29.

[consumers] to receive electric service".[77] Austin Energy provides contributions to Community Programs described as "corporate sponsorships providing partnership and support to community, customer and civic organizations and events." 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.[78] Electric consumers do not have a decision-making say in which charities or community programs are funded through their rates.[79]

A PUC Rule limits the amount of advertising, contributions and donations that can be included in regulated utility rates to "three-tenths of 1.0% (0.3%) of the gross receipts of the electric utility for services rendered to the public."[80] Note that this limitation includes advertising, as well as contributions and donations.

Both economic development programs and community donations may benefit the broader community, and the City may legitimately decide to make these expenditures and contributions with funds generated by Austin Energy or by any other city department. However, to be consistent with the requirement that only reasonable and necessary expenses are allowed in the utility's cost of service, it is not appropriate to treat these as necessary expenditures for providing utility service. The Economic Development Program, donations, and contributions to

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77 Tr. at 303, ln. 22-24.

78 Exhibit ICA-21 (AE Response to ICA RFI 2-7).

79 Tr. 304, ln. 7-14.

80 Public Utility Commission of Texas Rules, 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).

community programs should all be treated as part of the General Fund Transfer ("GFT"). In this manner, economic development expenditures and charitable donations would be clearly segregated from utility expenditures.

The ICA's recommendation on this issue has no direct impact on rates, since the expenditures are simply transferred to the GFT.[81] The expenses would be clearly treated as non-utility expenses, improving transparency. When the city council establishes criteria for the size of the General Fund Transfer, it should incorporate the intended budget for such expenses into that criteria.

[Note: The ICA recommends similar GFT treatment for the funding of discounts provided to the electric customers that live outside the city limits of Austin. These discounts are also unrelated to any electric cost of service criteria. This recommendation would have a positive revenue requirement impact for consumers served within the city limits. See the discussion in Section VII.A. below.

I. Loss on Disposal

Austin Energy reported a test year loss for asset disposal, resulting in a proposed amount of $7,170,039 be included the revenue requirement.[82] NXP/Samsung recommends that this amount be disallowed as not known and measurable.[83] ICA supports, in part, the adjustment for loss on disposal of assets proposed by NXP/Samsung, but only as an $800,000 reduction to

81 Exhibit ICA-1, p. 29.

82 Exhibit AE-1, WP E-4.3.

83 Exhibit NS-1, pp. 33-34.

revenue requirement. AE witness Mr. Dombroski makes the point that this is a recurring expense and an actual expenditure during the test year.[84]

ICA acknowledges that this is a recurring cost, although the amount fluctuates considerably each year. Based on the 3 years of losses entered into the record, the ICA contends that a normalized average would be most reasonable treatment:

Losses on the Disposition of Assets[85]:

2011	$10,213,180
2012	8,108,821
2013	67,256

A normalization of these three years of experience would result in a $800,000 reduction to AE's proposed loss on disposal allowance.

J. Customer Care

AE uses an allocation method for sharing the expense associated with its Utility Customer Care Center ("UCC"), which provides services to various departments of the City of Austin.[86] ICA supports the additional allocations of this expense to other user departments, sponsored by NXP/Samsung witness Ms. Fox, totaling a $10,371,602 disallowance, thereby further reducing AE's responsibility for these costs.[87] Indeed, Austin Energy has not met its burden of proof that its proposed level of expense is just and reasonable to the provision of *electric service*. Ms. Fox testified that "Though the fees and charges are billed by the combined

84 Exhibit AE-2, pp. 27-28.

85 Exhibit NS-1, p. 34, ln 9-11, referencing AE's response to NXP/Samsung RFI 4.10.

86 Exhibit NS-1, pp. 31.

87 Exhibit NS-1, pp. 33.

billing system, and complaints and billing inquiries are directed to the Customer Care Service Center, there is no reason AE should be responsible for all costs; there is little justification for allocating 100% of a customer complaint expense to AE when there is evidence that a number of customer complaints regarding water are received and it is odd to think that in 2016 there is no way to track that type of data. Recent reports to Council concerning the number of water related complaints would indicate that someone is able to track complaints by type."[88]

In rebuttal testimony, AE witness Mr. Dombroski explains that the current allocation method was developed in 2002.[89] However, Mr. Dombroski fails to explain why Austin Energy allocates 100% of certain customer care functions to AE when these functions also serve other city departments. Mr. Overton testified that complaints are difficult to allocate, because a complaint could involve more than one city service.[90] But failure to isolate the nature of the calls as being related to electric service, as opposed to those calls about other city services, does not qualify as sufficient evidence to meet the burden of proof to charge all of such expenses to electric consumers through this rate review proceeding. Austin Energy has established that customers contact the center seeking assistance on questions and complaints regarding services provided by other city departments[91]; they have not established why it is reasonable to allocate 100% of certain customer care costs to Austin Energy.

[88] Exhibit NS-1, pp. 32, ln. 5-12.

[89] Exhibit AE-2, p. 30, ln. 1-6.

[90] Tr. at 224, ln. 4-13.

[91] Tr. at 229-231.

K. Rate Case Expense

The ICA recommends that the amortization of the actual rate case expense for this proceeding match the time period commitment that AE makes for conducting its next rate review. If AE commits to initiating its next cost of service rate review within the next 2-3 years, as the ICA recommends, then it is reasonable to recover those expenses over the next three years. If, however, AE claims that it wants to conduct the next rate review in 5 years hence, then rate case expense should be amortized over 5 years, as NXP/Samsung is recommending.[92]

L. Outside Services

The ICA takes no position on this issue at this time.

M. Reserves

1. Reserve Funding

Austin Energy proposes to change the Rate Stabilization Fund into a "Power Supply Stabilization Reserve", which the ICA believes is a reasonable approach in order to insulate ratepayers from market volatility.[93] Austin Energy further recommends the reserve should maintain a cash balance at the midpoint between 90 and 120 days of Net Power Supply expenses.[94] The purpose of the fund is to "mitigate unpredictable fluctuations in Net Power Supply costs in order to stabilize rates and meet affordability goals."[95]

Austin Energy relies upon support for its recommended funding level from the NewGen study found in Appendix I of the Master Appendices. After evaluating the risk to Austin Energy

[92] Exhibit NS-1. P. 37.

[93] Exhibit ICA-1, p. 23.

[94] Exhibit AE-1, Tariff Package, Bates p. 99; Exhibit AE-8, p. 14.

[95] Exhibit AE-1, Tariff Package, Bates p. 101.

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.[96] However, 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."[97] 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."[98]

It is not reasonable to fund this reserve based on the "worst case scenario" and to assume that all volatility will meet the ERCOT market price cap.[99] The analysis does not 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 worst case event.[100] 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.[101] Therefore, the ICA is recommending that this reserve be

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[96] Exhibit AE-1, Appendix I, Bates pp. 475-477.

[97] Exhibit AE-1, Appendix I, Bates p. 475.

[98] Exhibit AE-1, Appendix I, Bates p. 476.

[99] Exhibit ICA-1, pp. 24-25.

[100] Exhibit ICA-1, pp. 24-25.

[101] Exhibit ICA-1, p. 25.

funded at 90 days of net power supply costs, rather than at 120 days or at 105 days. A 90-day level of funding is on the low end of a range that is still characterized as "worst case scenario".[102]

The funding limit for the current Rate Stabilization Fund is based on 90-days, and AE offered no evidence or commentary to suggest that that 90-day limit has proven to be insufficient to serve the goal of mitigating fluctuations in energy prices. Therefore, there is no justification for increasing the ceiling to 120 days for the fund that would replace the current Rate Stabilization Fund.

The ICA also disagrees with using net credit balances in the PSA to fund this reserve, rather than simply including them in an over/under collection calculation.[103] The larger the required 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, 2016.[104]

In summary, Austin Energy's previous experience does not demonstrate that the current 90-day funding policy is unreasonable or likely to be breached. In addition, AE has not demonstrated that it is necessary to convert fuel refunds into reserves in order to meet a higher reserve level. If AE faces conditions which justify moving fuel credit balances into this fund, AE can address those extraordinary conditions with the city council and request an exception to the normal policy of returning fuel refunds to customers.

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102 Exhibit ICA-1, pp. 24-25.

103 Exhibit ICA-1, p. 25.

104 Exhibit ICA-1, p. 25.

2. Policies

The ICA takes no position on this issue at this time. The AE policies on reserves have yet to be adopted.

N. Property Transfers

1. Energy Control Center

The ICA recommends that Austin Energy be ordered to make an adjustment to its cost of service reflecting the $14.5 million transferred to the utility due to the sale of land at 301 West Ave. Austin Energy received $14.5 million from the sale of the 301 West Avenue Property. The City Council directed that $14.4 million of the amount was to help fund the new Energy Control Center (ECC) on Riverside Drive.[105]

Austin Energy does not include this amount in the calculation of its cost of service in this proceeding.[106] Austin Energy claims it did not include the transaction because it was outside the test year and is a one-time non-recurring event.[107] ICA disagrees with Austin Energy's reasoning. In rate making, test year adjustments should be made for nonrecurring, special or out-of-period revenue items that occur before the evidentiary record closes. For example, the NARUC Rate Case and Audit Manual states: "The auditor will also want to review any sales of plant or equipment that have occurred since the last rate case, and determine if any gains or losses from the sale are being properly treated."[108]

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[105] Exhibit AE-5, p. 8, l. 7-11

[106] Exhibit AELIC-20, p. 2

[107] Exhibit AELIC-20, p. 3

[108] http://www.ipu.msu.edu/library/pdfs/NARUC%20Ratecase%20Audit%20Manual.pdf

Austin Energy has failed to show that it has properly treated this revenue and applied $14.4 million toward the cost of the new ECC as directed by Council. The ICA cannot quantify the effect of AE's failure to meet its burden of proof based on the record. However, ratepayers deserve to have the effect of this transaction recognized in the revenue requirement approved in this current rate review proceeding. Austin Energy should be ordered to calculate the impact and recognize it in the revenue requirement calculations. The ICA requests that the IHE find that the transaction is known and measureable and then require AE to quantify the cost of service impact of effectuating the city council's directive to use the proceeds to fund the cost of the new Energy Control Center.

2. Seaholm South Substation Land

The ICA takes no position on this issue at this time.

3. Vacant Lot at 2406 Ventura Drive

The ICA takes no position on this issue at this time.

4. Vacant Lot at 3400 Burleson Drive

The ICA takes no position on this issue at this time.

5. Holly Street Plant

The ICA takes no position on this issue at this time.

III. COST ALLOCATION

Three parties offered class cost of service study (CCOS) results into the record of this rate review proceeding, each varying significantly in the manner in which they allocate production costs (and discussed at length in Subsection III.C. below):

- Austin Energy witness Mr. Mancinelli, who used a version of the "12CP" method,
- NXP/Samsung witness Mr. Goble, who used a version of the Average & Excess Demand/4CP method ("AED-4CP"), and
- Independent Consumer Advocate witness Mr. Johnson, who presented a replacement cost version of the Base-Intermediate-Peak method ("BIP-R").

All three production cost allocation methods employed are recognized in the NARUC 1992 Cost Allocation Manual (NARUC CAM), and as explained below, the varying results show that CCOS are imprecise instruments that are sensitive to alternative classifications within a range of reasonable choices.[109]

The ICA believes that the allocations contained in its CCOS proposal, as performed by its expert witness Mr. Clarence Johnson, is the most reasonable approach on the record of this proceeding. Mr. Johnson's testimony reviewed the reasonableness of functionalization, classification, and allocation decisions within his CCOS study.[110] AE has made the excel workbook for the model of its CCOS publicly available for the parties to analyze, and Mr. Johnson implemented his recommendations and derived his own CCOS results by modifying the AE model spreadsheets.[111] On behalf of the ICA, Mr. Johnson's CCOS proposal shows that the various customer classes are close enough in cost responsibility to justify a significantly wider sharing of the overall revenue requirement reduction resulting from this rate review proceeding. The ICA's CCOS proposal provides support for meaningful electric base rate reductions for

109 Exhibit ICA-1, p. 73.

110 Exhibit ICA-1, pp. 31-70.

111 Exhibit ICA-1, p. 31.

AE's residential and small business consumers, even while their large commercial customers receive bigger rate reductions.

The intent of a CCOS 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. 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 CCOS can provide guidance to the regulator, but considerations other than the CCOS also are appropriate in determining the ultimate allocation of revenue responsibility among customer classes (as will be discussed in Section V. on Rate Design below).

Specific contested CCOS issues, involving disagreements among the parties over functionalization, classification, and allocation, are discussed in the following subsections.

A. Functionalization of the 311 Call Center, FERC 920 Administration and General Labor Costs and New Service Connection Fees

1. 311 Call Center

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".[112] But a relatively small portion of the expense is based on usage (number of calls attributable to AE); most of this expense is directly assigned to AE and supports the disaster recovery center.[113] AE justifies the expenditure because it provides back up to AE's normal operations.[114] This Center enables Austin Energy to operate in emergency mode due to severe storms or disaster conditions. However, AE recommends functionalizing this cost as *customer-related*, based on the argument that the call center is driven by call volume, which it says is "best associated with the number of customers".[115] AE's rebuttal testimony further argues that the call center "back up" function should be considered similar to the normal call center and thus allocated in the same way. However, this ignores the fact that the conditions which would lead to the use of the disaster recovery center as a back-up call center are likely to be associated with severe events and most of the calls to be outage-related. Customer reports of outages are one of the principal means of identifying the location of outages and determining when the repairs have been effective.

The ICA disagrees with AE's *customer-related* functionalization of this expense. The primary function of the 311 Call Center pertains to system reliability and maintaining continuous

[112] Exhibit ICA-1, pp. 66-67.

[113] Exhibit ICA-1, p. 67.

[114] Exhibit ICA-1, p. 67.

[115] Exhibit AE-3, p. 19.

delivery of power. Disaster recovery is focused on repairing and restoring power service. According to AE's response to the ICA's request for information ICA-8-16, the vast majority of Austin Energy's total payment for the 311 Call Center (**90.5%**) is based upon the value to the utility for access to the disaster recovery center.[116] The expense is more reasonably functionalized to "Distribution", because distribution facilities are most related to maintaining power delivery.[117] Therefore, the ICA recommends functionalizing A417 to Distribution, allocating the expense to classes based upon distribution O&M expense.[118]

2. FERC 920 Administrative and General Labor Costs

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.[119]

Functionalization is process of assigning these 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). But typically, Account 920 personnel are responsible for a broad scope of management activity, not just supervising the

[116] Exhibit ICA-37.

[117] Exhibit ICA-1, p. 67.

[118] Exhibit ICA-1, p. 67.

[119] Exhibit ICA-1, p. 51.

utility's employees. Therefore, the ICA recommends modifying the functionalization allocator for A920.

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 all aspects of the utility's operations, and it makes sense that their salary costs are recovered broadly across functions.[120]

Because AE is a non-managing partner in the South Texas Project ("STP") and Fayette Power Project ("FPP"), 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).[121] Although these two plants constitute approximately 55% of non-fuel production expense, the plants' labor expense is not 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.[122] ICCA witness Mr. Johnson allocates account A920 on the basis of non-fuel O&M expense, excluding A&G.[123]

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

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120 Exhibit ICA-1, p. 52.

121 Exhibit ICA-1, p. 52-53.

122 Exhibit ICA-1, p. 53.

123 This allocator is designated "O&MxAG" in the cost of service study.

comparison, understates the allocation of cost to Production. This fact confirms that the exclusions of FPP and STP labor costs from the labor allocator biases AE's allocation of A&G to the Production function downward.[124]

Functional Percentages[125]

	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%

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.[126]

AE witness Mr. Mancinelli claims that high voltage service customers should only have to pay for indirect costs related to high voltage infrastructure, and that Mr. Johnson's A&G proposal would cause large electric customers to pay too much for overhead costs.[127] This ignores the fact that the large electric customers are high load factor, and consume the largest quantities of energy when the baseload STP and FPP plants are generating electricity. Therefore,

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124 Exhibit ICA-1, p. 53.

125 Exhibit ICA-1, p. 53.

126 Exhibit ICA-1, p. 54.

127 Exhibit AE-3, p. 22.

understating the overhead assignable to these power plants will minimize the large customers' cost causal responsibility. Moreover, Mr. Johnson's use of an O&M allocator is reasonably related to the functions of management.[128] Presumably the top management of the Company pays 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. The A&G expense assigned to each function is classified to sub-functions based on the function's labor expense.[129]

Mr. Johnson's testimony points out that, for consistency, the change in functionalization of A920 should be carried through the sub-functionalization process. 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, the ICA recommends that distribution function A920 costs be sub-functionalized on the basis of distribution O&M expense, instead of distribution payroll expense.[130]

3. New Service Connection Fees

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."[131] However, contrary to the

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[128] Exhibit ICA-1, p. 54-55.

[129] Exhibit ICA-1, p. 55.

[130] Exhibit ICA-1, p. 55.

[131] Exhibit AE-1.

implication of such a rationale, the fee does not recover the incremental facility costs of new services and new meters.[132] This fee is only for ordering the initiation of new service.

The revenues from the service initiation fee 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.[133]

B. Classification of Production Costs

1. Introduction

In order to understand the proper treatment of production costs, it is important to first understand 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.[134]

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.[135]

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[132] Exhibit ICA-1, pp. 69-70, citing AE Response to ICA RFI 7-3.

[133] Exhibit ICA-1, p. 70.

[134] Exhibit ICA-1, p. 31.

[135] Exhibit ICA-1, p. 32.

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.[136]

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. 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.[137] 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

[136] Exhibit ICA-1, p. 32.

[137] Exhibit ICA-1, p. 32-33.

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.[138]

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.[139]

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.[140] 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.[141] 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.[142]

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

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[138] Exhibit ICA-1, p. 33.

[139] Exhibit ICA-1, p. 33.

[140] Exhibit ICA-1, p. 33-34.

[141] Exhibit ICA-1, p. 34.

[142] Exhibit ICA-1, p. 34.

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.[143] 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.[144]

First, demands have to be served reliably throughout the year, which points toward allocating on the basis of multiple hours of demand.[145] 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.[146]

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"):[147]

> 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.

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

[144] Exhibit ICA-1, p. 34.

[145] Exhibit ICA-1, p. 35.

[146] Exhibit ICA-1, p. 35.

[147] NARUC Electric Utility Cost Allocation Manual at p. 49.

The NARUC CAM cites the utility system planning process as justification:[148]

> 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 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.

The NARUC CAM accurately describes 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.[149]

2. Production Non-Fuel O&M Expense

AE classified all production non-fuel O&M expense as demand-related in its CCOS. The customary approach is to split these expenses between demand and energy. ICA witness Mr. Johnson, who has testified in rate cases involving every investor owned electric utility in Texas, said, "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

[148] NARUC Electric Utility Cost Allocation Manual at p. 53.

[149] Exhibit ICA-1, p. 36.

in Texas, SWEPCO, SPS, and El Paso Electric Co. classify a portion of production non-fuel O&M expense as energy-related."[150] Although 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, AE chose not to use this classification in the cost of service study presented in support of its proposed tariffs.[151] ICA witness Mr. Johnson recommended classification based on the NARUC Cost Allocation Manual (CAM) guideline, which is sometimes called the "cost accounting classification method," and is consistent with WP F-2.4, the workpaper which AE declined to implement. The use of this cost accounting classification method previously has been approved by the Texas PUC.

In the NARUC CAM, some accounts are classified entirely as either energy or demand. However, the CAM splits most accounts 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. From a cost accounting perspective, labor costs are fixed over a short run period and materials and supplies tend to be consumable or disposable.[152]

The rebuttal testimony AE witness Mr. Mancinelli disagrees with the NARUC CAM, claiming that "its guidelines pertaining to the classification of production infrastructure must now be interpreted in light of new market conditions", and then proceeds to dismiss those

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150 Direct Testimony of Clarence Johnson at 49.

151 Id.

152 Id.

guidelines because they were written before the deregulation of wholesale power markets and the Electric Reliability Council of Texas ("ERCOT").[153] But Mr. Mancinelli's attempt to distance himself from the NARUC CAM is surprising given his endorsement of the NARUC cost accounting method for production O&M expense to Austin Energy as recently as eight months ago. In a November 30, 2015 email to Austin Energy, Mr. Mancinelli recommends using a cost classification method "in alignment with the Cost Accounting (CA) Method".[154] Mr. Mancinelli's email makes no reference to the NARUC CAM as being outdated, proceeding to state in his own words that "The CA method is a well known and well used cost classification method described by NARUC. With respect to the Production Function, the method classifies cost as either demand-related or energy-related based on FERC accounting, hence the name."[155] The email also notes that in a recent Texas PUC case, Southwest Public Service Co. the PUC used the CA method along with AED/4CP.[156] Since the ERCOT nodal market opened in late 2010, it is inconceivable that this fact escaped his attention when he wrote this email in November 2015. And, thus, his contention that ERCOT market dispatch alters the applicability of the NARUC cost accounting classification method is also not credible.

Contrary to Mr. Mancinelli's current testimony that the NARUC CAM method is outdated, the classification approach continues to be consistent with cost causation.[157] A large proportion of maintenance expense is classified as energy-related. Like most mechanical

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153 Exhibit AE-3, p. 23.

154 Exhibit ICA-24, AE's Supplemental Response to TLSC's 1st RFI, p. 2102.

155 Exhibit ICA-24.

156 Referencing PUC Docket No. 43695.

157 Exhibit ICA-1, p. 50.

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.[158] Furthermore, a significant portion of operational expenses classified as energy-related consist of lubricants, coolants, and fluids which are consumed in proportion to the hours of generation operation.[159]

C. Allocation of Production Costs

ICA witness Mr. Johnson recommends using the Base-Intermediate-Peak Method ("BIP") for allocating production plant among customer classes, developing a variant of BIP which recognizes the specific characteristics of AE's generation investment.[160] The NARUC CAM identifies BIP as an accepted production demand methodology which falls within the "time-differentiated" category of methodologies.[161] 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.[162]

A number of energy-based and time of use CCOS 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.[163]

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[158] Exhibit ICA-1, p. 50.

[159] Exhibit ICA-1, p. 51

[160] Exhibit ICA-1, pp. 38-49.

[161] NARUC CAM at pp. 60-62.

[162] Exhibit ICA-1, p. 38.

[163] Exhibit ICA-1, p. 38.

Some of the methods are more data intensive because they reflect hourly time of use costs (e.g., probability of dispatch method, or "POD"). These methods are more difficult to administer, and may not be well-suited for recognizing ERCOT dispatch.[164]

ICA witness Mr. Johnson testifies that BIP will produce class allocation results similar to more data intensive time of use methods; with any difference in results not justified by the additional complexity of the capacity utilization models. BIP, as modified by Mr. Johnson, represents a reasonable balance between the relative simplicity and complexity of the alternative methodologies.[165] He cites several compelling reasons for recommending BIP. 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, and therefore, the BIP method reflects production cost causation criterion discussed in Subsection III.B., above.[166] Second, the methodology appropriately recognizes that, over the last 30 years, AE historically relied upon nuclear and coal generation to reduce total fuel cost.[167] 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.[168] Fourth, AE has considered the BIP methodology and, therefore, is aware that it represents a reasonable methodology for the AE system.[169] Fifth, AE's previous cost of service consultant, R.W. Beck (later called "SAIC"), recommended using BIP during the public involvement

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[164] Exhibit ICA-1, pp. 38-39.

[165] Exhibit ICA-1, p. 39.

[166] Exhibit ICA-1, p. 39.

[167] Exhibit ICA-1, p. 39.

[168] Exhibit ICA-1, p. 39.

[169] Exhibit ICA-1, p. 39.

("PIC") process for the 2011 rate request.[170] The consultant pointed out that BIP is consistent with the characteristics of ERCOT market dispatch.[171]

Mr. Mancinelli, who says he wrote the report for PIC described above, filed rebuttal testimony which now attempts to "walk back" his earlier recommendation in favor of BIP. A review of R.W. Beck's full recommendation to the PIC supporting BIP is ICA Exhibit 38; and an examination of that document shows that the recommendation was not a casual conclusion, but, in fact, was a well-thought out and persuasive analysis of the method. According to that report, the BIP method "more accurately reflects the way in which the utility incurs costs for producing electricity and how customer class characteristics, including energy demand and energy use, drive these costs," and "allocates generation costs from a broader perspective, taking into consideration the economic value of generation in the broader context of the market and the price protection such resources provide to AE customers given market uncertainty."[172]

NXP/Samsung witness Mr. Goble's testimony points out that the City Council approved Average & Excess-4CP (AED-4CP) in 2012; however, AE used the BIP method to support the ultimate revenue distribution adopted by the City Council.[173] 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

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[170] Exhibit ICA-1, p. 39, referencing AE Response to ICA RFI 7-11.

[171] Exhibit ICA-1, p. 39, Footnote 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."

[172] Exhibit ICA-3, p. 53, p. 60.

[173] Exhibit ICA-1, p. 40, Exhibit ICA-2, p. 6.

12 CP) in this case.[174] The ICA believes that BIP is actually a *better match* with ERCOT market characteristics than 12 CP alone.[175]

The BIP method identifies the plant investment assignable to base, intermediate, and peak utilization.[176] The South Texas Project (nuclear) and Fayette Power Project (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.[177] Steam-fired gas units and combined cycle gas units at Decker Power Plant and Sand Hill Energy Center are assigned as intermediate generation.[178] 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.[179] 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.[180] Solar and wind power involve relatively high capital

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[174] Exhibit AE-3, p. 30.

[175] Exhibit ICA-1, p. 40.

[176] 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 Mr. Johnson's formulation of BIP.

[177] Exhibit ICA-1, p. 40.

[178] Exhibit ICA-1, pp. 40-41.

[179] Exhibit ICA-1, p. 41.

[180] Exhibit ICA-1, p. 41.

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.[181]

Mr. Johnson then developed class allocation factors.[182] Base capacity was 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.[183] The capacity factor of these units is a 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).[184] 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.

Mr. Johnson developed two variations of BIP class allocation factors.[185] 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." In order to avoid a distortion in the relative value of Base, Intermediate, and Peak hours simply due to the timing of plant installation dates, Mr. Johnson developed a "replacement cost" version of the method.[186] Based on this adjustment to

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[181] Exhibit ICA-1, p. 41.

[182] Exhibit ICA-1, pp. 41-42.

[183] Exhibit ICA-1, pp. 41-42.

[184] Exhibit ICA-1, p. 42.

[185] Class allocation factors for both versions are shown on Exhibit ICA-1, Schedule CJ-2.

[186] Exhibit ICA-1, p. 42.

the method, all plant costs are converted to the same year's dollars, so that the values for Base, Intermediate, and Peak generation can be compared on an economically equivalent basis.[187] This replacement cost version of BIP (BIP-R), adjusts the Base, Intermediate, and Peak ratios to reflect the costs of generating technologies in 2014 dollars,[188] utilizing 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.[189] The DOE generation cost estimates are used by electric utilities (including Austin Energy), regulatory commission, and regional transmission organizations as generic plant costs.[190]

ICA witness Mr. Johnson recommends using the BIP-R, and his class cost of service results incorporate BIP-R as the production demand allocation factor. Plant cost comparisons based upon equivalent overnight dollars provide the most reasonable results.[191] Mr. Johnson also produced a version of BIP which utilizes actual net plant costs from the CCOS study for the baseload, intermediate, and peak components, which is labeled BIP-N. Mr. Goble's rebuttal testimony criticized the BIP-R, due to its reliance on DOE capital cost projections. However, these criticisms are not applicable to BIP-N; and the allocation factors for BIP-N are shown on Exhibit ICA-1, Schedule CJ-2. As shown on Schedule CJ-2, the allocation factors for BIP-N and BIP-R are reasonably close to each other. Since adoption of the methodology is more important than the particular version which is used, ICA can also support the BIP-N factors, if the Impartial Hearing Examiner finds that version to be preferable.

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[187] Exhibit ICA-1, p. 42.

[188] Exhibit ICA-1, p. 42.

[189] Exhibit ICA-1, p. 42.

[190] Exhibit ICA-1, pp. 42-43.

[191] Exhibit ICA-1, p 43.

As confirmation of the BIP results, Mr. Johnson also compared the results of his BIP-R method to another energy-weighted production demand methodology, a formulaic approach termed Average & Peak-12 CP (A&P-12 CP). Under certain simplifying assumptions, this method is mathematically equivalent to a time of use capacity utilization method.[192] The resulting Adjusted A&P-12 CP produces class allocation factors almost the same as BIP-R, as shown on Schedule CJ-2 of Exhibit ICA-1. This confirms that a time of use based methodology will produce results approximately the same as BIP-R.

Now that AE operates in the ERCOT nodal market, it is important that the production demand methodology recognizes different types of generating plants.[193] 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.[194] 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.[195] For generation planning purposes, the Price Duration Curve for ERCOT is more relevant to Austin Energy than the load characteristics of the individual utility.[196] The Price Duration Curve will provide information on the number of hours that each generation unit is likely to operate, thereby

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

[193] Exhibit ICA-1, p. 45.

[194] Exhibit ICA-1, p. 45.

[195] Exhibit ICA-1, p. 45.

[196] Exhibit ICA-1, p. 45, Footnote 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 Exhibit AE-1, Figure 3-4 at page 3-15 of AE's Tariff Package Proposal.

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.[197] Mr. Johnson provides examples of how the ERCOT market affects the types of generating plants owned by AE.[198] Production demand allocation methods such as the ICA recommended BIP-R methodology are consistent with the capital-energy trade-offs associated with generation entry into the ERCOT market.[199]

NXP/Samsung witness Mr. Goble proposes to allocate production costs using an Average & Excess Demand/4CP ("AED-4CP") method.[200] However, this AED-4CP method should be rejected because it produces results which do not take into account the role of energy use in system planning, because it relies too heavily on only four hours of the year to allocate almost one billion dollars of generation investment, and because it ignores the effect of ERCOT dispatch on generation cost causation.[201] The ICA-recommended Baseload-Intermediate-Peak methodology is superior to either AE's 12 CP method or the NXP/Samsung method which uses a version of the AED-4CP method.

Mr. Goble emphasizes that the Texas PUC has approved the AED-4CP in previous utility rate cases. While it is true that Texas Public Utility Commission ("PUC") potentially has appellate jurisdiction over rates outside the city, the City of Austin has original jurisdiction over the retail rates set in this rate review proceeding and has the authority to base its decision on the

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[197] Exhibit ICA-1, p. 45.

[198] Exhibit ICA-1, pp. 46-48.

[199] Exhibit ICA-1, p. 49.

[200] Exhibit NS-2, pp. 8-27.

[201] Exhibit ICA-2, pp. 4-5.

merits applying to AE's unique situation.[202] Moreover, the Texas PUC has not yet addressed the appropriate production demand methodology for an ERCOT electric utility since the ERCOT nodal market structure was put in place. ICA agrees with Austin Energy's position that the AED-4CP method is not consistent with the ERCOT dispatch system.[203] No Texas PUC precedent exists for the appropriate production demand methodology to use as a guide under the current ERCOT market structure, and as explained above, the ICA's recommended BIP method is better suited to this new ERCOT nodal market structure.

Mr. Goble's AED-4CP formula appears to allocate costs in part on the basis of energy usage (average demand), but that appearance is largely a mathematical illusion, particularly if coincident peak data is used, as Mr. Goble has proposed. The AED-4CP formula is a circuitous route to estimating the class shares of 4CP demands, which in turn *allocates costs to only four hours*.[204] If the load factor for the AED-4CP calculation is derived from 4CP, the results of A&E/4CP are the same as a straight 4CP allocator. Minor adjustments, such as converting "negative" excess demands to zero (such as the Texas PUC's typical formulation), or using a different load factor may cause the A&E/4CP to diverge slightly from 4CP. This change is slight because it usually affects only the lighting classes.[205]

Mr. Goble cites the NARUC Cost Allocation Manual (CAM) to oppose AE's 12 CP methodology.[206] However, the NARUC CAM does not support the AED-4CP method which he

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[202] Exhibit ICA-2, p. 5.

[203] Exhibit ICA-2, p. 5.

[204] Exhibit ICA-2, p. 6

[205] Exhibit ICA-2, p. 7.

[206] Exhibit NS-2, pp. 20-21.

employs. The NARUC CAM cautions against the insertion of coincident peaks into this formula stating that reliance upon coincident peak ("CP") demands for the Average & Excess ("A&E") method will preclude the methodology from achieving the purported aim of recognizing energy use (average demand):[207]

> If your objective is – as it should be using this method – to reflect the impact of average demand on production plant costs, then it is a **mistake** to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. [emphasis added].

The table below, shows the difference between the AED-4CP and 4CP by rate class, rounded to tenth of a percentage point:

A&E/4CP Allocator Minus 4CP Allocator[208]

	Difference (Percentage Points)
Residential	-0.2%
Secondary 1	0.0%
Secondary 2	-0.1%
Secondary 3	0.0%
Primary Total	0.0%
Transmission Total	0.1%

This table proves, that for all practical purposes, Mr. Goble's AED-4CP method is a simple 4CP approach that heavily relies upon only four hours of the year for its allocations of production cost.

207 NARUC Electric Utility Cost Allocation Manual (1992) at p. 50.

208 Exhibit ICA-2, p. 8.

Mr. Goble has previously supported the Probability of Dispatch (POD) allocation method.[209] The NARUC CAM lists both POD and BIP among the family of "production stacking" allocation methods.[210] Unlike AED-4CP, POD spreads generation plant costs to all 8,760 hours of the year. POD recognizes that the South Texas Project would be dispatched in as many hours as it is capable of running, and assigns the costs to time periods accordingly.[211] Mr. Goble's testimony discusses why AED-4CP is preferable, in his opinion, to a 12 CP method. But he does not say that AED-4CP is preferable to an allocation methodology that accounts for the dispatch of generating plants.

NXP/Samsung's AED-4CP method should be rejected as overly simplistic and inconsistent with ERCOT dispatch principles. If power plants were built to serve load in only four hours of the year, the utility would always construct gas peaker units because that reflects the cheapest conventional technology for generating power during a minimal number of hours. However, Austin Energy builds base load and intermediate plants because these technologies are expected to minimize total costs over a larger number of hours.[212]

D. Allocation of Distribution Costs

1. Transformers and Substations

The ICA disagrees with the way that AE classifies transformer costs as 100% demand-related.[213] Line transformers and related devices (such as capacitors and voltage regulators) are

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[209] Mr. Goble testified in support of the POD method in CPL Docket Nos. 8646 and 9561 before the Texas PUC.

[210] NARUC Electric Utility Cost Allocation Manual (1992).

[211] Exhibit ICA-2, pp. 9-10.

[212] Exhibit ICA-2, p. 10.

[213] Exhibit ICA-1, p. 55.

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. ICA recommends allocating A362 and A368 costs on the basis of class summer energy use.[214] 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.[215]

Transformers are related to energy losses. 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.[216] 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.[217] Although the influence of energy on transformer investment has always existed, recent federal changes have provided a more apparent illustration of the effect. ICA witness Mr. Johnson has reviewed of this issue in various electric utility cases, and believes that the higher investment cost of meeting the

[214] Exhibit ICA-1, p. 55.

[215] Exhibit ICA-1, pp. 5-56.

[216] Exhibit ICA-1, p. 56.

[217] 10 CFR 431.191, *et. seq*.

transformer energy efficiency standard appears to be in the range of 10% - 24%.[218] Austin Energy estimates a 9% increase in network vault transformers due to DOE 2016 energy efficiency standards.[219] With respect to previous DOE transformer standards, AE preempted the cost impact by installing transformers which met the new standards before the regulations went into effect.[220] Transformer procurement costs affect energy loss levels, which in turn affect AE's fuel and purchased power costs.

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.[221]

Capacitors and related devices in A368 are used to reduce energy losses. Properly applied capacitors "return their investment very quickly" by saving "significant sums of money in reduced losses."[222] 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.[223] Furthermore, distribution substations convert transmission voltage to distribution voltage, and therefore also are a source of energy losses.[224] Station equipment in A362 consists of transformers, capacitors, and similar devices which should be

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[218] Exhibit ICA-1, p. 56, Footnote 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.

[219] Exhibit ICA-11 (AE Response to ICA Request 1-6).

[220] Exhibit ICA-11 (AE Response to ICA Request 1-6).

[221] Exhibit ICA-1, p. 57.

[222] Exhibit ICA-1, p. 58, citing Electric Power Distribution Equipment and Systems at 273, T.A. Short, EPRI Solutions, Inc.

[223] Exhibit ICA-1, p. 58.

[224] Exhibit ICA-1, p. 58.

allocated on a comparable basis to A368, except that the allocation applies to primary voltage customers as well as secondary customers.[225]

ICA recommends using a kWh allocator for unbundled distribution costs.[226] This is consistent with a Regulatory Assistance Project ("RAP") report published for NARUC on the implications of unbundling for distribution rate design.[227] The report recommended that a portion of distribution costs be allocated on an energy basis, for both embedded and marginal cost of service studies:[228]

> [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.

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[225] Exhibit ICA-1, p. 58.

[226] Exhibit ICA-1, p. 58.

[227] Weston, Harrington, Moskovitz, Shirley, And Cowart, Charging for Distribution Utility Service: Issues in Rate Design, (Dec. 2000).

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

According to the RAP report, distribution investments that are incurred to reduce energy expense are appropriately allocated on an energy basis. This is consistent with the conclusions of the ICA.

The Texas utility 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 Mr. Johnson's 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.[229] ICA witness Johnson's recommendation in this case is consistent with that process, recognizing both energy use and the higher demand summer season.

2. Meters and Services

The AE CCOS developed 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 pertains to the traditional meter function.[230] 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.[231]

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[229] *Application of Center Point Electric Delivery for Rate Increase*, Docket No. 38339, Order on Rehearing at p. 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."

[230] Exhibit ICA-1, p. 63-64.

[231] Exhibit ICA-1, p. 64.

There is an incremental cost for installing smart meters, as opposed to electro-mechanical meters.[232] The cost of a manual residential meter is $48 and the cost of a comparable smart meter is $190.[233] 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.[234] With smart meters, 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.[235] 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 generation.[236] Customers benefits arise from enhanced ability to manage energy costs, shift loads, and identify wasteful uses of electricity.[237] AE recognizes most of these functions and continues to activate meter functions which enable these benefits.[238]

The avoidance of meter reading expense constitutes as much as one-half of the net present value benefit of smart meter investment,[239] 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

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232 Exhibit ICA-1, p. 64.

233 Exhibit ICA-1, p. 64.

234 Exhibit ICA-1, p. 64.

235 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.

236 Id.

237 Id.

238 AE Response to AELIC Request 9-23 and 9-24.

239 Exhibit ICA-1, p. 65, referencing “Costs and Benefits of Smart Meters for Residential Customers”, pp. 31 – 34.

demand is a reasonable measure for these functions. Therefore, ICA witness Mr. Johnson allocates meter investment on a 60% weighted customer and 40% production demand basis.[240]

AE also classified the service drops as demand-related distribution. The NARUC CAM specifies that services are properly classified as customer-related. The ICA recommends changing the classification of services to customer, which is consistent to the method employed by other utilities.[241]

3. NCP Allocator for Other Distribution Facilities

Class non-coincident demands (NCP) normally are used to allocate most demand related distribution costs, including allocation of poles, conductors, and substations.[242] Austin Energy applies the 12 NCP method to allocate poles, conductors, and substations, and Mr. Goble proposes to replace this allocator with a NCP allocator limited to the summer season.[243] The 12 NCP method used by AE is an average of class NCP for each of the 12 months. Mr. Goble's method utilizes each class' highest demand during the four-month summer period. The purpose of the NCP demand method is to recognize load diversity and the localized nature of distribution planning. Mr. Goble's summer NCP method dilutes the recognition of both factors.[244] ICA supports AE's use of 12 NCP to allocate poles and conductors, and opposes Mr. Goble's proposal to use a summer NCP allocation.

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[240] Exhibit ICA-1, p. 65, Footnote 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.

[241] Exhibit ICA-1, p. 65.

[242] Exhibit ICA-2, p. 10.

[243] Exhibit AE-3, p. 43; NS-2, pp. 24-27.

[244] Exhibit ICA-2, p. 10.

Load diversity is an important economy of scope in the electric utility industry. When class loads have a similar profile, increased demand imposes higher costs on distribution facilities. However, as more and different types of loads are combined within a local area served by distribution facilities, diversity benefits reduce the cost associated with additional new load.[245] Different types of loads can be complementary, with the peak of one profile occurring outside the peak of the other type of load. Loads tend to become increasingly diverse for more upstream facilities, since the local area served is expanded. Local area facilities closest to the end user tend to be more homogenous, even though some local areas may have a significant variety of customer profiles.[246] Given that customer classes tend to have profiles which are more homogenous, class maximum demands are assumed to be most representative of the most localized facilities. By restricting the NCP demand to summer months, Mr. Goble's method limits the recognition of diversity of loads between classes, because classes with high demands outside the summer season are insulated from the allocation of distribution costs associated with their high demand periods.[247]

Most utilities use NCP methods for distribution, but Mr. Johnson believes that the conventional approach for utilities is to use NCP demands based on class maximum demand for the annual period.[248]

[245] Exhibit ICA-2, p. 11.

[246] Exhibit ICA-2, p. 11.

[247] Exhibit ICA-2, p. 11.

[248] Exhibit ICA-2, p. 12.

E. Allocation of Customer Service (Including Uncollectible) Costs

1. Uncollectible Expense Allocation

AE's proposed direct assignment of uncollectible expense should be rejected. Instead, the ICA recommends that uncollectible costs should be allocated on the basis of revenues ("Rev Req allocation" or "revenue allocation").[249] AE directly assigns uncollectible expense based upon its bad debt experience during 2014 for each customer class. A more reasonable method is to allocate uncollectible expense in proportion to a revenue requirement allocation factor. The direct assignment method was rejected by the Texas Public Utility Commission in an Entergy rate case (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:

> 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.[250]

If one accepts the direct assignment concept, the class allocations should reflect the future risk exposure posed by each customer class.[251] The direct assignments tend to be based on experience over a relatively short period of time. The magnitude of the uncollectible expense in

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[249] Exhibit ICA-1, p. 60.

[250] *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). The Texas PUC reaffirmed this policy for allocation of uncollectibles in the 2015 rate case, Application of Southwestern Public Service Co. (Docket No. 43695).

[251] Exhibit ICA-1, p. 62.

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.[252] 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 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.[253] The cost of service study assigned no uncollectible cost to Secondary >300 kW (due to lack of information).[254] 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.[255] The more reasonable solution is to allocate uncollectible expense as a cost of doing business which should be spread proportionately to all customer classes.

[252] Exhibit ICA-1, p. 63.

[253] Exhibit ICA-1, p. 63, referencing AE Response to ICA RFI 2-29.

[254] 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.

[255] Ibidem.

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

2. Meter Reading

AE allocates meter reading expense on the basis of number of customers. The ICA proposes to allocate meter reading expense based upon the weighted customer allocator applied to meters.[256] Meter reading expense is obviously 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.[257]

3. Customer Service Accounts

The ICA modified the allocations that AE's CCOS made for the following accounts: 908 – 917 (Customer Assistance, Informational Advertising, Miscellaneous Informational Expense, Advertising Expense, and Miscellaneous Sales Expense).[258] Except for the portion of this expense allocated to Key Account customers, AE allocates these accounts based on number of customers by class.[259] 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. There is no reason to believe that the costs of achieving

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256 Exhibit ICA-1, p. 66.

257 Exhibit ICA-1, p. 66.

258 Exhibit ICA-1, p. 67.

259 Exhibit ICA-1, p. 67.

such general objectives will vary in proportion to the number of customers.[260] 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. AE fails to adequately support its decision to allocate this costs 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.[261]

Austin Energy directly assigns 14% of these accounts to Key Account customers, and the ICA CCOS accepts the direct assignment of this portion of the accounts.[262] However, Mr. Johnson 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.[263] 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

[260] Exhibit ICA-1, p. 68.

[261] NARUC CAM at p. 104.

[262] Exhibit ICA-1, p. 69.

[263] Exhibit ICA-1, p. 69.

applied to energy efficiency programs, thereby recognizing that some customer assistance and informational activities direct consumers to energy efficiency programs.

F. Allocation of Energy Efficiency Service (EES) Charge

Austin Energy waited until its rebuttal testimony to propose a dramatic re-allocation of the rate recovery for the Energy Efficiency Services ("EES") Charge, which would nearly double the EES rate that is currently charged to residential customers.[264] Because of the late timing of this proposal, the ICA was procedurally unable to analyze this change and to respond to it in its written testimony. AE did not include this EES re-allocation in its CCOS analysis, and further acknowledged at the hearing that this EES re-allocation proposal was "not fully vetted".[265] AE failed to meet its burden of proof to establish on the record a sufficient back-up justification for this departure from the current allocation method, and it failed to meet its burden of proof to show that this re-allocation from large customers to residential customers is reasonable.

AE did respond to discovery during the hearing to show the approximate impact of the change on typical residential consumers using 1,000 kWh/month (an additional $2.24) and consumers using 2,000 kWh/month (an additional $4.48).[266] Since this pass-through charge reflects energy efficiency program expenditures, additional expenditures will likely cause these impacts to grow larger incrementally as energy efficiency budgets increases, subsequent to the conclusion of this rate case, if the re-allocation is approved.

If this new EES re-allocation proposal is adopted, the resulting rate impacts would be great enough to ensure that almost all residential customers would receive a rate *increase* from

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[264] Exhibit AE-7, Kimberly Rebuttal Testimony, pp. 15-16.

[265] Tr. 1006, ln.15-23 (Maenius).

[266] Exhibit ICA-34 (AE Response to ICA RFI 8-11).

this rate review proceeding.[267] Residential customers would be receiving a net increase in rates at the same time that AE proposes to decrease its overall system revenues and to provide rate reductions to its largest commercial customers.

The ICA also disagrees with AE's position that the new allocation of energy efficiency services is consistent with cost causation. AE's method is based on total incentive payments by rate class. But this is not the appropriate representation of cost causation. The energy efficiency program is undertaken for the purpose of reducing future utility revenue requirements, in the form of lower production plant, purchased power, and fuel expenses, which in turn benefits all ratepayers, not just the participating class. The incentive payments are a means to achieving that objective, but are not the underlying cost causal basis for energy efficiency programs.

Therefore, the heavy re-allocation of EES costs onto residential customer is unreasonable, if based simply upon AE claim that residential customers tend to take advantage of energy efficiency programs in greater numbers than do customers in other classes. AE witness Ms. Kimberly acknowledged at the hearing that the utility largely designs their energy efficiency programs to pass the "total resource cost test" and analyzes its energy efficiency programs to see if they pass the "nonparticipant test".[268] The total resource cost test "measures the net cost of an energy conservation program, viewing the program as a utility resource option."[269] Ms. Kimberly agreed that if a program passes the nonparticipant test, then it may indicate that the program reduces future revenue requirements for all customers (i.e., by delaying or avoiding the

[267] Exhibit ICA-34; Exhibit ICA-26; Tr. 1082-1090 (Dreyfus).

[268] Tr. at p. 241.

[269] https://beopt.nrel.gov/sites/beopt.nrel.gov/files/help/Total_Resource_Cost_Test.htm

need for the utility to invest in new electric generation facilities).[270] AE's energy efficiency programs are intended to benefit far more customers than the customers who are actually receiving the programs directly. The purported theory behind the late-filed EES re-allocation proposal does not properly account for the possibility of system-wide benefits, which is a fundamental objective for which the utility is promoting energy efficiency programs in the first place. If approved, residential customers would be paying nearly double for the EES charge, while larger customers get a free ride on system-wide benefits related the underlying energy efficiency programs.

IV. REVENUE DISTRIBUTION / ALLOCATION / SPREAD

Class revenue distribution involves the assignment or allocation of a system revenue increase or decrease to rate classes. 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*.[271]

AE proposes an approximate $24.5 million base revenue reduction. This decrease will be larger if adjustments recommended by ICA and other parties are adopted. Based on its 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.

Based upon its own CCOS as a guide, the ICA contends that the revenue decrease should be distributed broadly among the customer classes generally. AE is publicly owned, and excess revenues should be broadly shared among different types of customers. ICA witness Mr.

[270] Tr. at pp. 241-242.

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

Johnson used his CCOS study to determine the customer classes which are far below cost—in this case, the lighting classes.[272] For those classes, his proposal leaves the base revenues unchanged. In addition, he used the CCOS study result to assign a base revenue increase to Transmission >20 MW, 85% LF.[273] AE's rate filing explains that this particular 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 larger revenue decrease to be distributed among the remaining classes.

ICA then proposes to allocate the revenue decrease on the basis of class shares of kWh consumption. This is a compromise allocation. The kWh methodology produces a more favorable revenue reduction for higher load factor customer classes than would 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, based upon the ICA's direct case position supporting a $41 million rate reduction. Based upon the ICA's post-hearing position—a $63,216,000 annual revenue reduction—larger percentage reductions should be applied to each customer class:

Residential	**-8.7%**
Small Secondary	**-7.1%**
Medium Secondary	**-9.2%**
Large Secondary	**-11.9%**

[272] Exhibit ICA-1, p. 74.

[273] Exhibit ICA-1, p. 74-75.

Primary Classes	**-14.7%**	**to -20.0%**
Transmission (non-contract)	**-8.9%**	

If the IHE approves a different revenue reduction than ICA's proposal, the same allocation method should be used.

V. RATE DESIGN

A. Billing Adjustment Factor

The ICA opposes NXP/Samsung's proposed adjustment to change the allocation of the $2.9 million billing adjustment to revenues.[274] Mr. Goble's testimony attempts to insulate certain customer classes from the reduced revenue effect. AE attempted to reconcile billed revenues with book revenues in its cost of service study. Because AE cannot access information regarding the classes which caused this downward adjustment in revenues, AE allocates the adjustment on a prorated basis among classes.[275] Mr. Goble believes that AE should have maintained adequate records of rebilled revenues by classes. He contends that larger customers in the higher voltage primary and transmission classes are less likely to have experienced such rebilling, and proposes to shield those customers from any reduction in revenues. Thus, he would allocate the adjustment to the remaining classes, increasing costs allocated to residential and small commercial classes.

While it would have been preferable if AE could have provided data by class for this adjustment, in the absence of such information, insulating larger customers from this adjustment

[274] Exhibit ICA-2, p. 12.

[275] Exhibit ICA-2, p. 12.

is arbitrary.[276] By definition, if no information regarding the causal classes is available, we cannot determine that larger customers bear no responsibility. Mr. Goble may be correct that rebillings are less frequent among such customers. But, even if less frequent, an incident which occurs among large customers generally will involve a larger amount of revenues. Larger customers are not immune from meter error, administrative errors, transpositional errors etc. Without additional information, a pro rata allocation of the adjustment is more equitable than arbitrarily removing certain classes from the allocation process.[277]

As an alternative proposal, Mr. Goble suggests that the adjustment could be denied based on AE's failure to maintain adequate records to support the reduced revenue level. ICA does not object to this alternative recommendation.[278]

B. Seasonal Power Supply Adjustment

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), simultaneously setting the summer and non-summer rates during the normal budget process, using historical PSA costs.[279] The ICA does not object to this proposal. High summer bills produce the most difficulties for household budgets, and potentially the elimination of the base rate summer/winter differential will moderate bill impacts and reduce customers' need for deferred payment plans.[280] To some extent, this can be viewed as a trade-off

[276] Exhibit ICA-2, p. 13.

[277] Exhibit ICA-2, p. 13.

[278] Exhibit ICA-2, p. 13.

[279] Exhibit AE-2, p. 37.

[280] Exhibit ICA-1, p. 82.

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.[281] 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 methods.[282] 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.

C. Residential

1. Customer Charge

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.[283] The ICA further believes that the customer charge should remain unchanged until all of AE's rates are reviewed in the next rate proceeding.

The ICA disagrees with several underlying assumptions made by AE on the nature of the residential customer charge. 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.[284] AE's position is not surprising, because it is

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[281] Exhibit ICA-1, pp. 82-83; Footnote 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.

[282] Exhibit ICA-1, p. 83.

[283] Exhibit ICA-1, p. 76.

[284] Exhibit ICA-1, p. 76.

consistent with pricing strategies commonly espoused by many utilities. But while raising customer charge levels creates a constant revenue stream to the utility, the strategy also shifts cost recovery to the least elastic[285] component of rates; customers have no means of controlling the size of their bill in response to a customer charge increase---other than going without electricity. 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, and this is good ratemaking policy.

AE's $10 residential customer charge is currently higher than any of the other bundled electric utilities in the state: $6.00 for ETI; $5.00 for El Paso Electric Co.; $8.00 for SWEPCO; and $9.50 for Southwestern Public Service Co.[286]

AE claims that there is a cost-based justification to charge a $22 customer charge.[287] However, this position is based on including inappropriate costs in the customer charge. Given its nominal pricing function, the customer charge should only recover costs which vary directly

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

[286] Exhibit ICA-1, p. 77.

[287] AE-1, Tariff Package at page 6-13.

with the number of customers.[288] 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 AE-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 this type of 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.

ICA witness Clarence Johnson's estimate of the customer charge that would be directly related to the number of customers results in a $9.35 monthly charge.[289] 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.[290] GFT is a return component which should not be recovered through the expense elements of the customer charge. Therefore, ICA 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

[288] Exhibit ICA-1, p. 77-78.

[289] Exhibit ICA-1, p. 78.

[290] Exhibit ICA-1, p. 78.

bundled electric utilities.[291] The calculation is set out on Schedule CJ-7 of Mr. Johnson's Direct Testimony.[292]

Public Citizen/Sierra Club ("PCSC") takes the position that the cost of service for multi-family dwellings is significantly lower than the cost of serving single family residences and recommend the customer charge for customers in multi-family units be lowered to $6 per month.[293]

Public Citizen/Sierra Club did not provide data to support a $6 customer charge for multi-family dwellings. It is not appropriate to change the customer charge for multi-family residences without a complete understanding of whether the change is cost-based and what impact the change would have on other residential customers. Furthermore, it is the positon of the ICA that the residential customer charge should recover only costs which vary directly with the number of customers. Limiting the customer charge to costs that vary directly with the number of customers is likely to find little differentiation between multi-family and single family residences.[294] Further, it would be unwise and premature to create a different customer charge for multi-family residences in this rate case when Austin Energy has plans to study customer-related cost recovery charges for multi-family, single-family and solar customers before the next rate review.[295]

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[291] *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).

[292] Exhibit ICA-1, Schedule CJ-7.

[293] Public Citizen/Sierra Club position statement, pp. 15-16.

[294] The customer charge does not include any delivery costs associated with lines, poles, and transformers. The principal cost components are customer accounting and billing, which vary on a per customer basis and which are unlikely to be affected by the type of dwelling unit.

[295] Exhibit AE-1, Tariff Package, Appendix E, Bates 372.

3. Tiered Energy Rates

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.[296] The advantage of an inverted block structure is that it provides a strong price signal for conserving energy.[297] 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.[298]

The ICA does not agree with the claim that high usage tiers are paying above their cost. This appears to be an attempt to use the CCOS study to define whether customers of various usage levels are above or below cost. ICA witness Mr. Johnson testified that 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. The attempt to graft CCOS results to individual customer usage levels can produce serious inaccuracies.[299] In essence, an assumption is made that energy use has a strict linear relationship

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[296] Exhibit ICA-1, 79.

[297] Exhibit ICA-1, 79.

[298] Exhibit ICA-1, 79.

[299] Exhibit ICA-1, p. 80.

with the various demand allocators in the CCOS, which may not be correct.[300] 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.[301]

The AE proposal would flatten 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 AE's Schedule H-3.[302] Up to 750 kWh, the average customer bill will increase 4% - 7%.[303] In the 750 kWh – 1000 kWh usage category, the average bill impact declines only slightly. The decrease grows to -2.5% in the 1750 – 2000 kWh group.[304] The average percentage decrease for the highest usage levels is just above -1%.

The ICA does not disagree with the objective of producing more revenue stability in the rate structure, but does not agree with increasing the bottom tier. The utility's revenue collections are particularly sensitive to weather conditions with its 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.[305] However, AE's approach to flattening the rate structure is problematic,

[300] Exhibit ICA-1, p. 80.

[301] Exhibit ICA-1, p. 80.

[302] Exhibit AE-1.

[303] Exhibit ICA-1, p. 80.

[304] Exhibit ICA-1, p. 81.

[305] Exhibit ICA-1, p. 81.

because it produces bill increases in the first tier of usage.[306] 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.

The ICA's revenue reduction recommendation assigns part of the system base revenue reduction to the residential class. A portion of the residential share of the base revenue reduction should be used to fund the changes to the rate structure without increasing rates for the lowest tier.[307] 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.[308]

AE should study the changing the number of tiers before its next rate case, as explained below. However, changing the number of tiers in this case, without the benefit of that study, would be overly disruptive and could produce unintended consequences.[309] There are potential advantages to reducing the number of tiers to three or four, and ICA recommends those alternatives should be studied. The potential 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.[310] 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

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306 Exhibit ICA-1, p. 81.

307 Exhibit ICA-1, p. 81.

308 Exhibit ICA-1, p. 81.

309 Exhibit ICA-1, p. 82.

310 Exhibit ICA-1, p. 82.

impacts for various options, as well as a more thorough analysis of the utility's long run marginal costs relative to embedded costs.[311] An analysis of long run marginal costs would provide better support for various tier options.[312]

3. Seasonal Base Rates

The ICA does not object to AE's proposal to eliminate the seasonality in base rates and establish a seasonal Power Supply Adjustment. See the discussion in Subsection V. B.

D. Non-Residential Customer Charge

The Sec. <10 kW (S1) class 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.[313]

Generally, ICA does not object to AE's rate design for these classes.[314] 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. (Although, as discussed below in Section V.G., the ICA objects to AE's proposal to terminate the HOW rate rider for these classes.)

The ICA has some concern about AE's adherence to strict fixed/variable pricing and the stated desire to pursue pricing which promotes high load factor. According to AE, a high load factor is "efficient."[315] The ICA is concerned is that AE will continue to use this philosophy to

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311 Exhibit ICA-1, p. 82.

312 Exhibit ICA-1, p. 82.

313 Exhibit ICA-1, p. 84.

314 Exhibit ICA-1, p. 84.

315 Exhibit ICA-1, p. 85.

increase the customer charge for S1 and S2 in the future, shifting more costs from energy rates to the demand charge in the future.[316] AE's 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.[317] *Economic efficiency*, on the other hand, is more focused on the long run impact of prices on the utility's marginal costs.[318] Rather than simply pursuing higher load factors, AE's pricing objective should balance both types of efficiency. Over the long run, pursuit of higher load factors may lead to higher costs and economically inefficient behavior.[319] Higher system load factors may shift the generation capacity expansion path toward higher capital cost baseload generation.[320] In addition, an 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 individual customers, the maximum demand as measured by the demand charge is poorly related to the coincident demands which are relevant to system load factor.[321] 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.[322]

[316] Exhibit ICA-1, p. 85.

[317] Exhibit ICA-1, p. 85.

[318] Exhibit ICA-1, p. 85.

[319] Exhibit ICA-1, p. 85.

[320] Exhibit ICA-1, p. 85.

[321] Exhibit ICA-1, p. 85-86.

[322] Exhibit ICA-1, p. 86.

AE should avoid raising the small commercial customer charge in the next rate review, if possible. Similarly, AE should refrain from shifting costs from energy rates to the demand charge in the next rate review.[323]

E. Load Shifting Voltage Rider and Additional Demand Response and Storage Tariffs

The ICA takes no position on this issue at this time.

F. S2 and S3 20% Load Factor Billing Determinant Adjustment

ICA supports Austin Energy's rebuttal testimony adjustment to limit bill impacts. AE proposes a 20% load factor floor for the S2 class.[324] 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).[325] 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.[326] If a S2 customer exhibits a load factor below 20%, the new floor provision will impute a lower level of billing demand.[327] This new provision could 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."[328] Special rates for customers with exceptionally low load factors are justified because the

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[323] Exhibit ICA-1, p. 86.

[324] Exhibit AE-1, Tariff Package at p. 6-23.

[325] Exhibit ICA-1, p. 84.

[326] Exhibit ICA-1, p. 84.

[327] Exhibit ICA-1, p. 84.

[328] Exhibit ICA-1, p. 84.

customer's unusual load characteristics are not well suited for demand charge billing.[329] The 20% load factor floor may also benefit some HOW customers.

G. Group Religious Worship Discount

ICA recommends extending the current transition mechanisms for Group Religious accounts until the next rate review, and after completion of Austin Energy's proposed studies of S1 rate class and of demand charges for commercial customers who peak outside the AE system peak.

Austin Energy proposes to end the current transition mechanisms available to Group Religious Worship Accounts (also referred to as "Houses of Worship" or "HOWs"), increasing revenues paid by this group by approximately $1 million.[330] It is important to note that although these transition mechanisms are often referred to as the "HOW discount" there is in fact no discount applied to every HOW account. Rather, the transition mechanisms were established by Council in 2012 to "mitigate rate shock"[331] for those HOWs that would experience large bill increases when they were moved from the residential to the commercial class.[332] There is great diversity among the HOW group and many accounts will see lower rates under the current rate proposal. However, others will experience significant bill increases.[333]

As part of its decision in the 2012 rate case Council approved transition mechanisms for HOWs consisting of 1) a *maximum charge* currently set at 13.051 cents per kWh, and 2)

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329 Exhibit ICA-1, p. 84.

330 Exhibit ICA-9, p. 30.

331 Exhibit AE-1, Tariff Package at p. 6-43, Bates 174.

332 Exhibit AE-1, Section 6.8.3

333 See selected bill impacts shown in Exhibit BC-5, pp. 1-2.

providing that *weekend hours* are not considered when determining billed peak demand for HOWs.[334] The Council also closed the discount rate to new customers, but in 2013 reversed that policy, allowing new facilities to take advantage of the rate.[335]

In its Tariff Package, Austin Energy stated the transition plan "mirror[ed] in part"[336] the policy of the Texas PUC in an El Paso Electric (EPE) rate case. In the 2009 EPE rate case, churches were caught in the 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.[337] 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.[338] 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.[339] 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, Mr. James Schictl, "As a practical matter, EPE and other parties will have another opportunity to

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

[335] Exhibit AE-1 at Bates 174, referring to Ordinance No. 20130909-003.

[336] Exhibit AE-1 at Bates 174.

[337] Exhibit ICA-1, p. 87.

[338] Exhibit ICA-1, p. 87.

[339] Exhibit ICA-1, p. 88.

address the rate limiter in EPE's 2017 rate case. In addition, EPE fully absorbs the cost of the limiter…"[340] The ICA's position is consistent with the approach of EPE to extend the transition.

Rate shock continues to be a concern for a number of the HOWs. A variety of factors coincide in this rate request to create rate shock conditions; these include the loss of the rate cap, the 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.

According to Austin Energy's calculations for a sample set of 9 HOW accounts, 5 would experience a monthly rate increase of over 10% in the winter months, with the largest rate increase of 30.1%, while in the summer 5 of the same 9 would also experience a monthly rate increase of more than 10%, with the highest rate increase at 19.7%.[341] In a rate proceeding where the customer class is proposed to receive a rate decrease, these results show unfair rate shock for these customers. While Dr. Dreyfus prefers not to characterize these results as rate shock, he admitted that adverse impacts on individual customers within a class should be considered.[342]

While Dr. Dreyfus' definition of rate shock applies to an entire class of customers, the disparate impacts within the class from AE's proposal, including the potential for large double-digit percentage impacts on individual HOWs, would undoubtedly be experienced by those customers as rate shock. It is unreasonable to change the current HOW tariff now, and it is especially premature when AE is planning to commence a study the issue.

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340 Docket No 44941, quoting the Rebuttal Testimony of James Schictl at p. 82.

341 Exhibit BC-5.

342 Tr. p. 1095, l. 9-17

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.[343] There are HOWs in the S1 class and HOW accounts in S2 that 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. So why eliminate the HOW tariff now, without the benefit of the upcoming study and evaluation of HOW issues?

For instance, some of the HOWs have demand that is principally off-peak, and have low load factors. As an example, a church may only use power for lights and heating/air conditioning and only for a brief number of hours on the weekend, but the demand charge causes this customer to incur that maximum hour charge as if it had used power every day of the week. Such customers would receive bills which exceed their cost impact on the system. 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 local area which encompasses numerous types of customers. In

[343] AE Exhibit 1, Attachment E

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.

The fact that the Council opened up the HOW "discount" rate to a new account in 2013 shows that the Council views the transition period as flexible. Further, 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 rates for most will be lowered. It is not fair to subject some HOWs to significant rate increases while doing nothing to mitigate these rate increases. Finally, it does not make sense to move HOWs off the transition mechanisms when Austin Energy plans to perform rate studies that might result in a more appropriate rate treatment for HOWs, including a study of peak usage measurement in the commercial class and the rate structure of the S1 class.[344] An 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.[345] 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.

ICA recommends the following:

- Extend the transition for HOWs—retain the cap of 13.051 cents per kWh and the practice of measuring peak usage only during weekdays. Preferably, AE should absorb the discount, instead of re-allocating the cost to other customers. This is consistent with NewGen's recommendation to provide relief from rate shock for low power factor customers without reallocating the cost to other customers. The transition should not end

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[344] Exhibit AE-1, Appendix E.

[345] Exhibit ICA-1, p. 90.

until after the two studies referenced above have been completed and the next rate case is completed.[346]

- 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.[347]

VI. VALUE OF SOLAR ISSUES

A. Commercial

ICA supports the conclusion of Austin Energy's rebuttal position on PCSC's proposal regarding a Value of Solar tariff for commercial customers.[348] Specifically, Ms. Kimberly states:

> While I disagree with some of PCSC's rationale for seeking a commercial VOS tariff, I do support the need for a comprehensive review of AE's solar rate structures. Austin Energy suggests undertaking a holistic review of both residential and commercial solar rates and supporting technologies such as smart inverters, panel orientation, storage, and demand response. Analysis is needed to determine what rates and incentives would be appropriate to provide fair compensation to solar customers, prevent cost-shifting amongst customers, mitigate negative impacts on the distribution grid, encourage the use of technologies or system design to provide local grid benefits, reduce costs, etc. This will require time for stakeholder engagement and analysis, and could result in development of a glide path to implementation of new rates to prevent sudden changes to customers' bills or utility costs.[349]

[346] Exhibit ICA-1, p. 90; In addition, the IHE should order AE to include HOW customers in the two studies above.

[347] Exhibit ICA-1, p. 90.

[348] Exhibit AE-7, p. 5, ln. 25 through p. 8 ln. 6.

[349] Exhibit AE-7, pp. 9-10.

Residential and commercial customers who are not solar customers, and thus at risk of bearing any cost-shifting, must be included in the stakeholder engagement and analysis to best achieve the goals enumerated by Ms. Kimberly.

B. Community Solar

ICA recommends a process for stakeholder engagement and analysis for a Community Solar tariff, similar to the process described by Austin Energy for a commercial solar VOS tariff[350] (also, see comments above on commercial solar). The same type of stakeholder process and analysis regarding issues such as fair pricing and prevention of cross subsidy is needed before a community solar tariff is approved by Council.

C. VOS Residential Tariff

ICA has no objection to including the formulas for the residential VOS tariff in the tariff schedules, per the discussion on the record.[351]

VII. POLICY ISSUES

A. Funding Discounts

ICA recommends imputing the value of the $5.8 million annual discount given to outside of city residents, rather than including this amount as a cost to be borne by other ratepayers inside the city.

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 maintains the outside city customers'

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[350] Exhibit AE-7, p. 9 ln. 20 through p. 10 ln.6.

[351] Tr. p. 680, ln. 23 through p. 686, ln. 13.

discount off of the proposed inside city rates. The amount of the outside city discount included in the AE proposal is $5.8 million.[352] AE admits that the inside/outside differential has no cost basis whatsoever.[353]

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 Austin Energy's CCOS study.

For cost of service purposes, ICA proposes 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, and properly reduces the level of "under recovery" that AE has assigned to the residential class.[354]

Austin Energy testified the purpose of the discount is to mitigate litigation risk.[355] However, it is unreasonable to force inside customers to pay higher rates as a result of the discount. Indeed, Mr. Dombroski's rebuttal to ICA's position is circular—he says that if the amount of the discount is imputed, then inside the city residential customers could be forced to

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[352] Exhibit ICA-1, p. 20, ln. 16-17

[353] Tr. at p. 305; Exhibit ICA-23.

[354] Although AE would not place this issue in its proposed briefing outline under the Revenue Requirement section, the ICA's proposal for revenue imputation of the $5.8-million-dollar discount is added to its Revenue Requirement calculations, due to the fact that the record of this proceeding contains no cost of service based justification for the discount.

[355] Exhibit AE-2, p.12.

bear the cost of any additional outside city discount—in other words, inside city customers would be in exactly the same situation that AE proposes to place them in.

> If outside city customers were to appeal AE's rates to the PUC and if the PUC were to order a significant change to the rates of outside city customers, AE would not be able to fund the change out of its reserves. Therefore, AE's inside city customers would be forced to bear the cost of those changes.[356]

The revenue imputation ensures that the cost of the discount is paid out of AE's margin rather than forcing inside 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.

B. Rates for Customers Inside and Outside the City Limits of Austin

ICA does not oppose the proposal made by Austin Energy to maintain the discount negotiated in Texas PUC Docket No. 40627 (conditioned on the revenue imputation proposal discussed in the previous subsection).

C. Piecemeal Ratemaking

ICA recommends 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.

There is an interrelationship among many cost of service components (i.e., expenses, investments, revenues) within a test year.[357] When adjustments are made to electric rates for one

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[356] Exhibit AE-2, p 12, l. 21-25

[357] Exhibit ICA-1, p.103.

item of expense outside of a full rate review of all components, then a mismatch can occur which distorts the overall cost of service.[358] 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. Similarly, changes to rate design with a class will result in "winners" and "losers". For example, it is well established that increases to fixed monthly customer charges has a disproportionate impact on lower usage customers.[359] 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*.[360] Changing electric base rates only in the context of a full rate review is fundamental to the integrity of cost of service utility regulation.

A guiding principle advanced by Austin Energy is that "The rate review process should be transparent, including public involvement".[361] 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 and the design of customer rates. 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

[358] Exhibit ICA-1, p.103.

[359] Exhibit ICA-1, p.103.

[360] Exhibit ICA-1, p.103.

[361] AE Exhibit 1, p. 017, Principle #8.

cost of service. ICA agrees with NXP/Samsung witness Fox that the public hearings associated with the city budget process are a far cry from the level of analysis and scrutiny given to AE's rates in this proceeding.[362] It is important to ensure that the rate changes and decisions made regarding rate design resulting from this proceeding will remain in place until the next full rate review, without the creation of any new mechanisms or rate designs that have the potential to cause isolated changes to electric bills.

While the Council and public may assume this proceeding will set rates until the next such rate review, AE has indicated that may not be their intent. 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."[363]

In rebuttal Dr. Dreyfus testified that he generally agreed with ICA's position that changes to base rate components and base rate design outside of a general rate review may lead to distortions. "However, I recognize that there may be exceptions to this policy when the City Council deems such an adjustment is in the public interest on balance."[364] An exception cited by Dr. Dreyfus were recent changes to rate design for the commercial class.[365]

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[362] Tr. p. 409, l. 4-18

[363] Exhibit AE-1, Bates p. 024.

[364] Exhibit AE-9, p. 19, l. 9-10

[365] Exhibit AE-9, pp. 18-19.

It frustrates the role of the ICA to have AE hint at potential near-term changes that would occur after this rate case, including significant increases to the residential customer charge. ICA is limited in this case to responding to Austin Energy's current proposals. Should AE propose changes to rates or rate design in the months or years after this proceeding concludes, there will be no ICA to provide analysis and comment. The ICA believes council's intention in hiring an ICA was to ensure residential, small commercial and HOW ratepayers are fully represented when changes are proposed to both base rates and base rate design.

D. Service Area Lighting

The ICA takes no position on this issue at this time.

E. Power Production Costs and Rate Treatment

ICA disagrees with DataFoundry's assertion that Austin Energy's production plant is "dedicated" to the wholesale market and should be included in retail rates and recommends the IHE reject this argument and DataFoundry's related adjustment to revenue requirement. ICA's position is consistent with the rebuttal testimony of Dr. Dreyfus for Austin Energy.[366]

All of the investor-owned bundled utilities in Texas buy and sell power in real time wholesale markets without excluding the associated power plant fixed costs from retail rate base. Only plant allocable to native load wholesale customers pursuant to FERC cost of service tariffs are excluded from those utilities' retail rate base. AE has no comparable native load wholesale customers. For the bundled utilities within ERCOT such as AE (i.e., non-opt in utilities), the ERCOT market structure represents a system for buying and selling power similar to a power pool. In a regulatory sense, this is no different than El Paso Electric Co. (EPE) or Southwestern

[366] Exhibit AE-9, p. 51-53.

Public Service Co. (SPS), which include power plant investment in retail rate base, but use revenues from opportunity sales of power and purchases of power on the wholesale market as an offset to retail revenue requirement. EPE's Palo Verde nuclear investment is located near the California border, and significant quantities of Palo Verde power are sold into the California market. The Texas PUC does not consider any of the Palo Verde investment to be dedicated to the wholesale market, but instead includes Palo Verde in EPE's retail rate base and uses margins on the sale of power as a reduction to retail revenue requirements.

F. Studies Supporting Future Cost of Service

ICA has two recommendations with regard to studies supporting future cost of service: 1) there should be no change to the House of Worship transition until after the study of weekend demand is completed and 2) AE should provide opportunities for customer involvement in these studies.

Appendix E[367] to the Tariff Package lists eight proposed studies address both residential and nonresidential rate design. Several of the studies directly relate to issues under debate in this case, including the level of the customer charge for multi-family residential properties, weekend peak demand, and disparities for some customers, including Houses of Worship, in the lower band of the S2 class.

[367] Exhibit AE-1, Appendix E, Bates p. 372-373.

ICA recommends the following:

- The identified studies should be completed prior to the next rate review. Austin Energy has agreed to this, but with the caveat that they are contingent on Council approval and funding.[368]

- Austin Energy should engage the Electric Utility Commission (EUC) 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.

G. Customer Assistance Program

ICA agrees with the rebuttal testimony of Austin Energy regarding the CAP program.[369] Mr. Robbins has identified shortcomings that may have allowed unqualified customers to be enrolled in the CAP program.[370] It is appropriate to review the enrollment process and to remove unqualified recipients from the program when they are identified, while ensuring that qualified

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[368] Exhibit AE-9, p. 65, l. 1-5

[369] Exhibit AE-6, p. 7 ln.8 through p. 11, ln. 18

[370] Exhibit Robbins-1, pp.7-8

and deserving customers are not also removed from the rolls. Austin Energy has already taken steps to address these enrollment questions.[371] ICA agrees with the testimony of Austin Energy that additional recommendations made by Mr. Robbins are not feasible, cost effective or in the best interest of customers.[372]

H. Customer Satisfaction

ICA recommends Austin Energy develop a plan to improve its customer satisfaction ratings, specifically related to the findings of the survey referred to as the "overall satisfaction survey", with a reported satisfaction rating of 59%.[373] Customer satisfaction is a key metric of utility performance and Austin Energy should strive for significantly improved customer satisfaction ratings. Austin Energy would not share the details of the overall satisfaction survey, and witnesses shared little information.[374] For both regulated and competitive utilities customer satisfaction is usually a contributing factor in earnings. For Austin Energy, superior customer satisfaction should be a goal on a par with the competitiveness goal established by Council. ICA applauds Austin Energy for continuing to provide walk-in service centers when many other utilities have discontinued them. These centers are valuable to customers and receive much higher satisfaction ratings of 88% for residential and commercial customers.

I. Pilot Programs

ICA has three recommendations with regard to pilot programs:

1) Remove the prepayment tariff from the 2016-2017 tariff schedule;

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[371] Exhibit AE-6, p. 7, ln. 8 through p.8, ln. 4

[372] Exhibit AE-6, p. 8, ln. 5 through p. 11, ln. 4

[373] Exhibit ICA-1 p. 92 ln. 2 through p.94, ln. 9.

[374] Tr. p. 878, ln. 19 through p. 881, ln. 20; Tr. p. 946 ln. 22 through p.949, ln. 11.

2) 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.

3) For pilots in general, ICA's testimony made several recommendations, including that stakeholder input should be sought in the development of the pilot, and proposed pilots should be reviewed by the Electric Utility Commission and the Council, separate and apart from the budget process.[375]

1. Prepayment pilot

In the FY 2016 budget Council approved a prepayment pilot that is included in the "Residential Service Pilot Program" section of the proposed City of Austin Tariff Schedule[376]. ICA and AELIC have raised objections to the prepayment pilot, including:[377]

- **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

[375] Exhibit ICA-1, pp. 10-11.

[376] Exhibit AE-6, beginning at Bates 664.

[377] Exhibit ICA-1, p. 99, ln. 4 through p. 100 l. 4

> 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.[378]

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.

- **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 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.[379]

These and other concerns and objections were not vetted or addressed by AE prior to initiation of the prepayment pilot, even though internal AE documents show that it was known

378 Exhibit ICA-1, p. 99, referring to AE response to ICA RFI 2-18, p. 236.

379 Exhibit ICA-1, p. 100, referring to AE response to ICA RFI 2-18, p. 181.

that prepayment programs have "high level risks" of disapproval by consumer groups or by City Council members.[380]

In rebuttal testimony and on cross examination Austin Energy has agreed to remove the prepayment tariff from the 2016-17 tariff schedule[381], and consistent with ICA's recommendation, to form a collaborative process for evaluation of the pilot prior to full deployment of any prepayment rate[382]. These agreements should be memorialized in the rate order.

2. Other pilots

For pilots in general, ICA's testimony made several recommendations, including that stakeholder input should be sought in the development of the pilot, and proposed pilots should be reviewed by the Electric Utility Commission and the Council, separate and apart from the budget process. Austin Energy testified it works collaboratively with low-income advocates on the CAP and arrearage management programs and with the environmental community on tariffs related to solar.[383] In Mr. Overton's rebuttal testimony he also appears to have agreed with ICA's recommendation:

> Austin Energy is always interested in receiving feedback from its customers and <u>before implementing a new project or program,</u> Austin Energy will develop the appropriate tariff revisions, hold discussions about the revisions with the Electric Utility Commission, City Council, and other stakeholders, and request Council's authority to proceed.[384] [emphasis added]

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[380] Exhibit ICA-1, p. 98, referring to AE response to ICA RFI 2-18, p. 200.

[381] Exhibit AE-6, p. 18.

[382] Tr. p. 886, ln. 2-6; Tr. p. 888, ln. 11-24; Tr. p. 890, ln. 1-23

[383] Tr. p. 889, ln. 11-25

[384] Exhibit AE-6, p. 18, ln. 6-10

J. Pick Your Own Due Date

ICA recommends 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. Austin Energy testified it is working on developing the technical capabilities of offering pick your own due date.[385] 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. The Texas PUC permits the electric utilities that it regulates to offer customers the option of choosing their own due date.[386]

VIII. STATEMENT OF POSITION / OTHER ISSUES

A. Late Payment Fees

ICA recommends eliminating late fees for customers in the CAP program, supporting in part the recommendation on late fees made by AELIC.[387] The purpose of the CAP program is to provide assistance to the city's most vulnerable customers. Imposing late fees on this group simply adds more to their cost burden. This action can be expected to both assist CAP customers

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385 Exhibit AE-6, p14, ln. 6-20; Tr. pp. 879 -881.

386 Exhibit ICA-1, p. 101 l.3-16

387 Exhibit AELIC-2 (Position Statement), p. 7

with affordability and reduce the buildup of bad debt. Furthermore, Austin Energy admits there is no cost basis for the fee.[388]

AELIC Exhibit 33A shows Texas Public Utility Commission Substantive Rules at Sec. 25.480 (c) prohibits the charging of late fees to customers in the competitive retail market who are receiving a low-income discount. In defending the late payment fee for residential customer, Mr. Overton testified AE's policy is "identical to the one outlined in the PUC regulations."[389] In fact, the policy is not identical to the PUC regulations because late fees are imposed on customers receiving a low-income discount, in other words, CAP customers. ICA recommends Austin Energy follow the Texas PUC's policy for retail electric providers in the competitive retail market and refrain from imposing late fees on CAP customers.

B. Regulatory Charge

ICA takes no position on the regulatory charge at this time.

IX. CONCLUSION

In summation, the ICA contends that the evidentiary record contains competent and sufficient support for a significant revenue requirement reduction for Austin Energy's electric rate revenues, and for a determination that residential household customers and small business customers in the City of Austin, Texas deserve to share in the benefit of this reduction through lower electric rates. Furthermore, the current tariff rates that now apply to the Houses of Worship should be studied further before being eliminated, in order to avoid unfair and adverse impacts to certain small HOW customers.

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388 Tr. p. 877, l.13-16

389 Exhibit 6, p.13 l. 1-3

The ICA respectfully requests that the Impartial Hearing Examiner issues a report that contains findings and recommendations consistent with those contain in this post-hearing brief.

Respectfully submitted,

John B. Coffman ______________________________
Independent Consumer Advocate

Submitted this date: June 10, 2016

CERTIFICATE OF SERVICE

The forgoing filing has been served upon all of the email addresses contained in the official Service List for this proceeding as found on the website for the Office of the City Clerk's website on this 10th day of June, 2016.