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

AUSTIN ENERGY'S CLOSING BRIEF

June 17, 2016

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CLOSING BRIEF

TO THE HONORABLE INDEPENDENT HEARINGS EXAMINER:

COMES NOW, Austin Energy ("AE") and files this Closing Brief pursuant to City of Austin Procedural Rule 8.3(e) and respectfully shows as follows:

I. INTRODUCTION

In this proceeding, AE is proposing to reduce its base rates by approximately **$24,559,000** annually. This is in addition to a $30,000,000 decrease eight months ago and a $70,000,000 reduction to the power supply adjustment ("PSA") tariff just two months ago. AE may also make further reductions later this summer to the regulatory charge and the PSA tariff. Cumulatively, these four rate decreases, all within a year of each other, could result in a decrease of approximately $150,000,000 to Austin Energy ratepayers.[1]

These reductions increase AE's competitiveness and directly address the City's affordability challenges. Notably, all of these reductions have been made voluntarily and without litigation. Moreover, AE continues to be a national leader in the development of solar, demand-side management, and renewable energy initiatives. In addition, this case represents a continuation of the transition that began in the last rate case. In 2012, AE began to modernize and revise its rate classes and the design of its rates. AE has proposed changes to the structure of

[1] While certain parties have complained about Austin Energy's rates compared to rates within the deregulated areas of Texas, these decreases demonstrate how the different utility paradigms that exist in our state function differently. That is, rates for vertically integrated utilities tend to move more slowly than in deregulated areas. Austin Energy's customers have benefitted from this lag for most of the past 14 years, and they will benefit again when rates increase in the deregulated areas.

several charges to more closely align with cost causation principles and has revised its reserve funding.

Of the 23 intervenors in this matter, two parties examined AE's revenue requirement. Those two parties, NXP Semiconductors, Inc. and Samsung Austin Semiconductor, LLC ("NXP/Samsung") and the Independent Consumer Advocate ("ICA"), represent divergent interests and propose significantly different revenue requirement and cost allocation recommendations to achieve greater rate relief for themselves. Meanwhile, other parties, such as Paul Robbins and Public Citizen/Sierra Club ("PC/SC") propose certain rate increases to further their policy objectives. For example, PC/SC's Fayette Power Plant ("FPP") debt defeasement and Energy Efficiency Service ("EES") proposals would increase rates by $40 million annually.

Intervenors' leanings are manifested in this proceeding in other ways as well. AE conceded to further rate reductions in its rebuttal case, but so did intervenors. The ICA changed his position on six revenue requirement issues in his brief, with each change resulting in a larger proposed rate reduction. In total, these changes added $22 million to his adjustments. Consequently, the ICA is now proposing a $63 million rate decrease. Moreover, although the residential class is $46.3 million below cost, the ICA is recommending an 8.7% *decrease* for residential customers.[2]

NXP/Samsung's bent is even more obvious in their attempt to justify a rate decrease. Despite their complaints, under AE's cost of service ("COS") recommendations, NXP/Samsung's rates reflect the actual cost to serve them. Accordingly, NXP/Samsung's presentation tries to slash the overall revenue requirement enough to justify a rate decrease for them. NXP/Samsung's brief ignores COS ratemaking altogether and urges setting Austin Energy's rates by combining the City's affordability goals with what NXP/Samsung believes

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[2] The change from $53 million to $46.3 million reflects the adjustment related to CAP revenues.

they should be paying in the deregulated portions of the state. This rhetoric is at odds with how cost of service regulation has been applied in all 50 states for nearly 100 years. Electric utility rates are not based on what customers would like to pay or what they think they should pay, but instead what it costs to provide electric service to those customers. Indeed, if the Public Utility Commission of Texas ("PUC") set rates for investor-owned utilities in the manner advocated for by NXP/Samsung, those rates would quickly be found confiscatory and illegal on appeal.

Even more absurd are the 12 pages of NXP/Samsung's brief asserting that Austin Energy's retail rates should be subsidized by wholesale transmission customers throughout the Electric Reliability Council of Texas ("ERCOT"). This entire argument is a red herring contrived to sway the Impartial Hearing Examiner ("IHE") and City Council to set Austin Energy's retail base rates lower than would otherwise be appropriate based upon allegations that Austin Energy's transmission service has excess revenues. Not only is this proposal illegal and bad policy, it would also likely result in a rate review by the PUC and possible legislative scrutiny if it were implemented. Quite simply, City Council does not have the legal authority to require wholesale transmission customers to subsidize AE's retail operations.

Many of NXP/Samsung's specific revenue requirement disallowances are equally extreme. For example, NXP/Samsung Witness Ms. Fox proposes to eliminate AE's entire outside IT support even though Austin Energy has historically relied on outside consultants and experts to assist it with projects requiring specific expertise or additional personnel. This translates into a $6,762,767 adjustment. Similarly, Ms. Fox eliminates all production plant expenditures, a $21,000,000 disallowance, even though Austin Energy has existing power production facilities that require capital improvement program ("CIP") investment. She eliminates the entire $7,200,000 of losses associated with the disposal of utility assets even though the test year amount proposed by Austin Energy is recurring and representative of past and expected future experience. These are just a few of the extreme and unsupported revenue requirement adjustments proposed by NXP/Samsung.

Just as they have done to the revenue requirement, NXP/Samsung and the ICA have made a number of allocation recommendations that are inappropriate and result driven. The parties' differences are particularly acute with respect to the allocation of production costs. AE proposes also setting production costs using the 12CP method. The 12CP method is appropriate for Austin Energy because it reflects cost causation principles and balances the interests of residential and commercial customers. In contrast, the ICA and NXP/Samsung advocate for adoption of allocation methodologies that shift costs to other customer classes whose interests they do not represent.

While making relatively few revenue requirement adjustments in its direct case, the ICA proposed several cost allocation methods that shift costs from the residential class to the commercial and industrial classes. However, none of these adjustments correctly match the nature of the expense with the proper allocator. For example, Mr. Johnson recommends adopting the base intermediate peaking ("BIP") allocation method which classifies a significant portion of fixed production costs (demand-related costs) as energy-related and allocates these costs to the various rate classes on the basis of energy. This recommendation shifts fixed cost recovery from low load factor residential customers to high load factor commercial and industrial customers. It is important to note that the PUC has not approved the BIP method in over 20 years. Mr. Johnson also recommends allocating uncollectible accounts (bad debt) to each rate class based on class revenue requirement rather than directly assigning these costs to each rate class. This recommendation blatantly shifts these costs from the residential class, which represents 90% of all bad debt, to commercial and industrial customers. Next, Mr. Johnson recommends administration and general ("A&G") labor expense be allocated to each class based on the class's allocation of non-fuel operation and maintenance expense. The inclusion of non-labor expense significantly shifts A&G labor costs to the production function. A&G costs are fixed in nature and do not vary with the amount of energy produced. Therefore, this recommendation shifts costs from low load factor residential customers to high load factor commercial and industrial customers.

For its part, Austin Energy presented a case that attempted to balance the interests of customers as well as the utility and the broader community. To that end, AE has proposed changes to its financial policies that will reduce rates. It is proposing to establish non-nuclear decommissioning funds to avoid future rate increases and reduce intergenerational inequities. Despite residential customers being significantly below cost, Austin Energy did not propose to increase their base rates. Unlike the intervenors, who myopically focus on the class or classes that they purport to represent, AE presents a holistic, and legally sound, approach to setting new base rates for its customers.

The Process

Throughout this case and in their briefs, certain parties have complained about the process established by the City of Austin for this proceeding. In particular, NXP/Samsung devote a full nine pages of their brief to complaining about the process. Although it is unnecessary to respond to all of their complaints, a few comments are in order to provide the IHE with some perspective.

Some parties have complained about the procedural schedule and "compressed timeline" as compared to a PUC case. Respectfully, these parties appear to be unfamiliar with the PUC rules or lack agency practice. This case was filed on January 25 and parties had until April 19 to propound discovery questions. This 85-day period is significantly longer than parties are allowed at the PUC, where roughly 60 days of discovery is more typical. Moreover, discovery responses are due within 20 days at the PUC. AE had only 10 days to respond to discovery. This was done even though Austin Energy responded to over 1,100 discovery questions, more than in its last PUC rate case, PUC Docket No. 40627.[3] The City also made every filing in the case available on-line and did not require any party to make paper copies in order to make participation easier and less costly. By comparison, in a case before the State Office of Administrative Hearings, parties must make 13 hard copies of briefs and motions in addition to providing copies to parties.

The schedule was also longer with respect to the filing of intervenor testimony. Intervenors had 99 days (i.e., January 25–May 3) to prepare testimony, which is approximately three weeks longer than at the PUC. While NXP/Samsung complained about not having enough time to prepare their case, they submitted a nine-page memo on April 7 directly to the Mayor and City Council members detailing all their specific adjustments and recommendations 26 days before their testimony was due. Parties were also allowed to file cross-rebuttal testimony and conduct discovery on Austin Energy's rebuttal testimony. Neither of these privileges is provided for in the PUC rules. In this case, the hearing on the merits commenced 127 days after the case was filed. This is approximately six weeks longer than would occur in a PUC case. Finally, parties were allowed four days of hearing, which is typical for large proceedings at the Commission.

Some parties have also complained about the piecemeal nature of this case. With one relatively minor exception, this is a base rate case. That exception is AE's proposal to change the structure, but not the level, of several of the pass-through rate tariffs in this review of its tariff. AE allowed other parties to propose new tariffs and, indeed, several have. In addition, for the parties' convenience, AE provided projected numbers for the pass-through rates. These

[3] *Petition by Homeowners United for Rate Fairness to Review Austin Rate Ordinance No. 20120607-055*, Docket No. 40627 (Apr. 29, 2013).

numbers were intended to give customers an approximation of the overall impact of this case and the budget process on their bills. Although several parties have sought to expand this case to address various issues, this is a base rate case. To those familiar with the law and the state regulatory scheme, this is not unusual. The law provides for an examination of fuel rates, energy efficiency costs, transmission costs, distribution costs, storm related costs, and advanced metering costs all outside the context of a base rate case. Indeed, no utility in the state has had an examination of its entire cost of service before the PUC in over ten years.

Another key point that bears repeating is that Austin Energy participates in a competitive wholesale market. Austin Energy is relatively unique in that it is a vertically integrated public utility that does not have retail choice but competes in a competitive wholesale power market. In fact, with the exception of AE's last rate case, Docket No. 40627, there has never been a case before the PUC involving such a utility. A consequence of this situation is that certain information must remain confidential, despite the fact that the City of Austin is a public entity subject to the Public Information Act ("PIA").[4] The legislature recognized this situation by providing exceptions to disclosure in the PIA for public utility competitive information.[5] As a result, certain information is competitively sensitive and is, therefore, unavailable in this case. It is ironic that the very parties seeking retail competition also complain about the realities of being a wholesale market participant. The fact is, competition does not necessarily foster transparency.

In summary, AE is a public utility. AE desires public input into the setting of base rates and entered this process in order to better serve its customers. This is the only time in over 20 years that a Texas utility has hired either an IHE or an ICA. It is also the only time that a utility has conducted a local rate hearing since Austin last did so in 1994. As noted by the ICA, "[t]he current rate review proceeding has allowed unprecedented public involvement and scrutiny of

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4 Tex. Gov't Code Ann. § 552.001-353 (West 2012 & Supp. 2015) (Public Information Act).

5 Public Information Act § 552.153: Confidentiality of Public Power Utility Competitive Matters.

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."[6] This deliberative process will help AE and the City Council reach the appropriate outcome in this case.

II. REVENUE REQUIREMENT

A. Residential Base Revenue Customer Assistance Program Adjustment

Austin Energy's initial filing did not account for revenues generated from a separate funding source under the Community Benefit Charge ("CBC") to reimburse the Customer Assistance Program ("CAP") discount expenses. This issue was raised by Austin Energy Low Income Customers ("AELIC") and the ICA during discovery. This error was acknowledged and discussed in Mr. Dombroski's rebuttal testimony.[7] This correction adds approximately $7,085,000 to AE's projected base rate over-recovery. Therefore, Austin Energy is proposing to *decrease* base rates by $24,559,000. This compares to the $17,474,000 decrease proposed in Austin Energy's initial filing. AE proposes this additional revenue be allocated using the same approach that was applied to its initial filing. However, if a class reaches its class cost of service, the remaining amount will be applied to the other classes.

No party objects to this correction or the amount of the adjustment.[8] However, the ICA "would use the revenues provided by this adjustment to fund a reduction for all classes, based upon [the] ICA's proposed revenue allocation."[9] Under AE's cost allocation recommendations, the "residential customer class is well below cost of service, by $53.4 million (11.3%), while

[6] Post-Hearing Brief of the Independent Consumer Advocate at 10 (June 10, 2016) ("ICA Brief").

[7] Rebuttal Testimony of Mark Dombroski, AE Ex. 2 at 9.

[8] AELIC initially proposed a different revenue number due to AELIC overstating the CAP funding revenue. This miscalculation is no longer in dispute.

[9] ICA Brief at 10.

certain non-commercial customer classes are above cost of service."[10] Even taking into account this additional revenue, the residential class continues to be significantly subsidized by the other customer classes. Accordingly, it is not appropriate to spread this revenue to other classes, including the residential class, that are already below cost. To do otherwise would exacerbate the existing subsidizations.

B. Decommissioning Funding

City of Austin Financial Policy No. 21 requires Austin Energy to set aside funds to pay for the eventual retirement and decommissioning of the utility's non-nuclear fuel generation fleet.[11] AE's non-nuclear fleet consists of Decker Creek Power Station ("Decker"), FPP, and Sand Hill Energy Center ("SHEC"). Funds must start accumulating no later than four years prior to commencement of decommissioning activities. In principle, AE would start collecting decommissioning funds as soon as a plant is energized; however, that has not been the practice to date. Thus, AE proposes to add $19.4 million of additional revenue to cover future decommissioning expenses.[12] Of the total adjustment, $14 million is earmarked for the retirement of Decker in the near-term, $3.75 million is set aside for the retirement of AE's portion of FPP in the mid-term, and $1.7 million is directed toward the eventual retirement of SHEC in the long-term.

AE calculated the $19.4 million in decommissioning expense based on the estimated number of years until the units are retired and the upper end of the range of estimated decommissioning costs (rounded to the nearest $1 million) for units 1 and 2 at Decker, AE's share of the FPP, and all of SHEC. The cost estimates were developed and reported by NewGen

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[10] Austin Energy's 2015 Cost of Service Study and Proposal to Change Base Electric Rates, AE Ex. 1 at 2-11.

[11] AE Ex. 1 at 371.

[12] AE Ex. 1 at 857 (WP D-1.2.5).

Strategies and Solutions ("NewGen") in a July 2015 study which examined the entirety of AE's reserved funds and policies.[13] The decommissioning costs of Decker units 1 and 2 are based on a detailed engineering cost estimate relying upon analysis specific to these facilities. Since the timing of the decommissioning of FPP and SHEC is further into the future, the estimates for FPP and SHEC are based on a benchmarking analysis of scaled costs from actual costs for decommissioning similar power plants, reported on a dollar per kW basis and then applied to the specific capacity of each unit at FPP and SHEC. This approach is less detailed, but given the length of time before these plants are decommissioned, is appropriate and yields reasonable estimates.

In response to AE's proposed decommissioning expense levels, three parties offer alternative recommendations for the IHE's consideration. AELIC suggests that the entire $19.4 million be disallowed or, in the alternative, that AE be permitted to collect approximately $5.7 million annually, an amount which reflects an increased amortization period and lower overall level of expense.[14] ICA proposes a total decommissioning expense level of $9.89 million, an adjustment which reflects a lower overall level of expense.[15] NXP/Samsung recommends a total of $12.6 million in annual decommissioning expenses to fund the retirement of Decker units 1 and 2 only, and recommends a disallowance of expenses associated with AE's other non-nuclear power plants until the Austin City Council provides specific direction about the retirement dates for each unit.[16] Additionally, AELIC[17] and NXP/Samsung[18] recommend that non-nuclear

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[13] AE Ex. 1 at 427-592.

[14] Post Hearing Brief of Austin Energy Low Income Customers at 5, 7 (June 10, 2016) ("AELIC Brief").

[15] ICA Brief at 10.

[16] NXP Semiconductors and Samsung Austin Semiconductor, LLC's Post Hearing Brief at 9 (June 10, 2016) ("NXP/Samsung Brief").

[17] AELIC Brief at 8.

[18] NXP/Samsung Brief at 9.

decommissioning expense not be funded through Operations and Maintenance ("O&M") expenses, but rather as a reserve. A fourth party, PC/SC, supports AE's proposed non-nuclear decommissioning policy and expense level. AE disagrees with the alternative recommendations of AELIC, NXP/Samsung, and the ICA on the basis that the three dissenting parties substitute their subjective judgement about the timing of retirement dates and the assumed cost of decommissioning activities.

AELIC's primary recommendation is a complete disallowance of non-nuclear decommissioning expense based on the fact that some of the information provided in NewGen's non-nuclear decommissioning reserve study was redacted for competitive matters concerns. AE held confidential portions of the engineering cost estimate because certain elements would reveal unit specific cost information and other elements would identify site-specific construction details. This information cannot be released publicly without jeopardizing AE's competitive position or without implicating safety concerns at the plant. AELIC's and other parties' insistence that AE could unilaterally waive the requirements of the PIA is an ongoing and flawed complaint. In fact, unlike state agencies, such as the PUC, local governments do not have the ability to issue protective orders to guarantee the confidentiality of sensitive information. Furthermore, the public has no expectation to confidential information in a local, public process, and AE has stated on numerous occasions that this rate review proceeding was never intended to afford the public different rights than those typically provided in other public processes at the City of Austin.[19] Finally, the IHE can review this confidential information and, on behalf of the public, make a recommendation to the Austin City Council on the reasonableness of the Decker decommissioning engineering cost estimate provided by AE. AE strongly recommends the IHE

[19] This issue is taken up in greater detail in Sections I. and VIII.C. of this brief.

reject outright any claimed disallowance based on complaints of how the PIA applies to AE at the local level.

AELIC's alternative recommendation, the ICA's proposal, and NXP/Samsung's proposal are all based on subjective interpretations of retirement schedules and overall cost levels. AELIC's alternative recommendation would extend the amortization period by an arbitrary amount of time and decrease the funding level by 48%, a percent reduction originally proposed by the ICA.[20] AELIC does not provide any rationale or calculation which support its amortization period, only stating, "[t]aking AE's high decommissioning cost estimates for each plant, amortizing that amount over the number of years until AE's presumed retirement, and adding the calculated amortized costs for each plant results in approximately $11 million for TY 2014."[21] While AELIC references the NewGen decommissioning reserve study, AELIC offers no alternative retirement dates, no new amortization period for each plant, or any way to validate the $11 million total test year expense level. The IHE should reject this arbitrary 48% decrease in decommissioning expenses outright.

Both AELIC and the ICA promote a 48% discount based on the fact that neither salvage value nor other estimated revenues from the sale of property or water rights were included to offset the decommissioning cost estimates. In total, the AELIC proposal reduces the TY 2014 decommissioning expense requirement by 71%. However, AE Witness Joseph Mancinelli specifically refuted these offsetting revenues in his Rebuttal Testimony.[22] Specifically, Mr. Mancinelli testified that there is too much uncertainty to include revenue from the sale of property or water rights because both the Decker and FPP sites will continue to be used for generation operations after the retirement of portions of those facilities. Additionally, the

[20] Direct Testimony of Clarence Johnson, ICA Ex. 1 at 20:4-5.

[21] AELIC Brief at 6.

[22] Rebuttal Testimony of Joseph Mancinelli, AE Ex. 3 at 12:6-13:8.

retirement of the SHEC site is too far into the future to adequately predict whether those land or water rights should be sold and if so, at what value. Furthermore, because the "cost estimates developed for FPP and SHEC did not have enough detail for such offsetting revenue assumptions," it would be imprudent to include a revenue amount that may ultimately be unrealistic.[23]

With regard to salvage and recycling value, Mr. Mancinelli testified that the uncertainty of those revenues was too great to reasonably include any offsetting amount in the cost estimates. "The sale of working equipment was similarly uncertain and AE's experience decommissioning the Holly Power Plant indicates the opportunity to obtain such offsets from the sale of equipment may be negligible."[24] He also reiterated that the cost estimates for FPP and SHEC were not conducted as engineering cost estimates but were based on benchmarked unit cost estimates from other decommissioning projects across the country. Thus, whatever high level recycling and salvage value those similar projects realized would be included in the benchmarked estimates.

If AE were to include these uncertain offsetting revenues and if the revenues were to fail to meet expectations, AE would be in the position of needing to seek additional revenues immediately from its customers to recoup unfunded decommissioning costs. Given the brief amount of time AE has to begin collecting reserves to fund the decommissioning of Decker units 1 and 2, it would be imprudent for AE to include these uncertain offsetting revenues in this initial expense request. Should the actual costs end being lower than expected, AE can apply the balance to funding decommissioning activities for FPP and SHEC and reduce required revenues in the next retail rate review.[25]

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[23] AE Ex. 3 at 12:21-22.

[24] *Id*. at 13:5-8.

[25] City Council policy requires a review of retail rates at least once every five years. The latest the next retail rate review would begin would be 2020, using an historical test year of 2019. *See* Financial Policy No. 17 in AE Ex. 1 at 371.

ICA Witness Clarence Johnson criticizes the decommissioning cost estimates for exceeding average benchmarked costs for each of the three plants.[26] According to Mr. Johnson, these higher than average cost estimates are due in part to the treatment of contingency funds for each of the three plants.[27] Mr. Johnson observes that the contingency amount included within the decommissioning cost estimates ranged from 10.7% for Decker units 1 and 2 to 30% for FPP and SHEC. Further, the 30% contingency for FPP and SHEC only applied to demolition costs, and not recycling and salvage offsets. He also mentions that the PUC does not permit contingency allowances greater than 10% for nuclear decommissioning and that it recently found, in a case for Southwestern Power Co., that a net salvage value of -2% should be applied to all production plant, implying depreciation must recover 2% above gross plant cost to cover decommissioning.[28] These are not persuasive arguments which justify a 48% reduction in the overall level of decommissioning expenses.

The fact that the PUC does not permit contingency allowances greater than 10% for nuclear decommissioning is not a relevant limitation since the approach and requirements for nuclear decommissioning are different from the analysis conducted for AE's non-nuclear generation facilities. However, it should be noted that:

1. The detailed Decker decommissioning estimate includes a 10.7% contingency on demolition costs (excluding salvage), which is very close to the PUC 10% nuclear decommissioning guideline; and

2. Seventy-two percent of the non-nuclear funding requirement included in the rate filing package ("RFP") is related to Decker.

So, although unintentional, the overall contingency associated with the total funding requirement is reasonably close to the PUC 10% guideline.

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[26] ICA Brief at 11-12.

[27] *Id*. at 12.

[28] AE Response to ICA RFI No. 8-15, ICA Ex. 36.

In contrast to the Decker decommissioning estimate, the FPP and SHEC decommissioning estimates were developed at a high level. Given these high level estimates, a 10% contingency would not reasonably reflect the uncertainty inherent in the analysis. Similarly, it is appropriate to apply the 30% contingency to the demolition costs for FPP and SHEC, excluding the recycling and salvage offsets, because unknown or unidentified costs are a more significant concern than potentially understated salvage revenues in the way this analysis was developed. Further, what the PUC decided for an investor-owned utility (i.e., Southwestern Power Co.) does not directly apply to AE, a municipally owned utility ("MOU"), because of the different way in which these utilities are regulated, develop revenue requirements, and recover costs for decommissioning.

Finally, Mr. Johnson's citation of a -2% net salvage value referenced from PUC Docket No. 43695 is of no importance in the initial establishment of a non-nuclear decommissioning reserve. However, it is important that non-nuclear decommissioning reserves are restricted for use in decommissioning Decker, FPP, and SHEC. When units at these plants are decommissioned, available funds will be used to offset actual costs. If actual costs exceed the funds accrued, additional revenues from rate increases will be required. In contrast, to the extent that actual costs are less than the funds accrued, funds can be applied to other non-nuclear decommissioning projects and allow for future revenue requirement reductions.

Notwithstanding this reality, Mr. Johnson concludes a 48% reduction to AE's annual decommissioning expense is reasonable based on his analysis and considering the benchmarking study conducted by NewGen. Similarly, NXP/Samsung Witness Marilyn Fox recommends a 35% reduction to AE's proposed decommissioning expense for Decker.[29] Both the ICA's and NXP/Samsung's recommended adjustments are based on the mean cost per kW for

[29] Rebuttal Testimony of Marilyn Fox, NXP/Samsung Ex. 3 at 30:3-5. Ms. Fox disallows all other decommissioning expenses not associated with Decker.

decommissioning different generation technologies approved by public utility commissions in various cases, as cited in the NewGen report. However, NewGen used the cost per kW for the different generation technologies as a point of reference to compare with the decommissioning cost estimates developed for AE's facilities. It is inappropriate to rely on the mean approved cost per kW from other plants when there is site-specific information based on a detailed engineering cost estimate available, as is the case for Decker. Moreover, the approved commission data validated the cost estimates developed for FPP and SHEC under a benchmarking approach. Thus, the amounts used by AE for decommissioning are appropriate.

Ms. Fox also seeks to justify her proposal to disallow collection of decommissioning expenses associated with FPP and SHEC by citing to the fact that the Austin City Council has not yet approved specific retirement dates for these plants. It is inappropriate, though, to exclude costs for FPP or SHEC simply because they are not currently scheduled for retirement.[30] AE is obligated to decommission its generation assets. This obligation accrues, and AE should set aside funds for this obligation, over the useful life of the assets, a concept supported by both Ms. Fox and PC/SC.[31] As noted above, ideally AE would begin setting aside funds for the eventual decommissioning of a plant the day it is put into service. Under this policy, customers that derive the benefits of generation also pay for its eventual decommissioning as the plant is in operation. This is how the cost for decommissioning a nuclear plant is managed. Further, it is similar to how most regulated utilities recover this cost in their depreciation rates, a fact mentioned by Mr. Johnson.[32]

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[30] It is also inconsistent with Ms. Fox's recommendation to allow recovery of decommissioning expenses for Decker units 1 and 2 as specific retirement dates have not been established for those units either.

[31] Closing Brief of Public Citizen and Sierra Club at 6 (June 10, 2016) ("PC/SC Brief").

[32] ICA Ex. 1 at 17:17-18:1.

While AE did not begin collecting decommissioning monies the day these plants started running, this does not mean that Austin Energy should further delay the process. The earlier AE starts the process of setting aside funds for each generation unit, the lower the potential rate impact and the more equitable the recovery of these costs.[33] Therefore, Ms. Fox's suggestion that no amounts should be set aside for FPP and SHEC until they are scheduled for retirement is contrary to the equitable recovery of these costs.

Finally, AELIC and NXP/Samsung recommend excluding decommissioning expenses from O&M expenses and, instead, suggest that non-nuclear decommissioning costs should be secured from depreciation expenses. This is an imprudent way to recover the costs associated with decommissioning generation assets because depreciation expense is a non-cash item in AE's cash flow methodology, where depreciation expense is fully offset by a corresponding revenue adjustment.[34] Instead, the appropriate recovery mechanism is an annual operating expense recovered from customers through rates and moved to a reserve fund for use when decommissioning activities commence. AE's method is consistent with the accounting treatment of nuclear decommissioning reserves and results in a funded liability on the balance sheet. AE's approach results in better alignment between the customers benefiting from the power plants while they are in service and the customers paying for the eventual dismantlement of the facilities in the future.[35] These are two objectives that Ms. Fox purports to support.[36] Recovering decommissioning expense as an annual operating cost is, therefore, consistent both with the cost causation theory since those customers who benefit from the production facilities

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[33] *See* Tr. at 769:19-770:2. *See also*, Tr. at 394:9-22.

[34] AE Ex. 1 at 767 (Schedule A, Column C, Rows 6 and 23).

[35] *Id*. at 487.

[36] Tr. at 412:14-414:14.

should pay for them and with the matching principle since decommissioning costs are recognized during the same period as production revenues.[37]

AE has a unique opportunity to fund this critical reserve under a revenue reduction scenario. Through these retail rates, AE proposes to fund the decommissioning reserve at the justifiable upper level while still reducing overall system rates. From a rate administration perspective, this strategy is prudent because:

1. Given the timing of the Decker decommissioning, immediate funding of the Decker component of the Non-Nuclear Decommissioning Reserve is critical.

2. Funding the Non-Nuclear Decommissioning Reserve at the justifiable upper end will reduce the risk of future funding requirements from rates.

3. AE will not have to reduce overall system base rates to an unsustainable level, only to raise them in the next rate case to recover expenses associated with decommissioning activities. Using a portion of current base rate revenues to fund the Non-Nuclear Decommissioning Reserve satisfies an important revenue requirement objective without raising rates. This outcome is more desirable compared to facing a similar funding requirement when an overall rate increase is required.

Although AE's historical practice of not setting aside funds for decommissioning its non-nuclear generation assets may raise intergenerational equity concerns, this issue will only be made worse by under-funding the decommissioning reserve. Thus, fully funding the reserve is the best way to mitigate this issue going forward. The flow of potential excess funding to the next decommissioning project is reasonable given the fact that AE has not started collecting decommissioning funds for plants that have been in service for a decade or more. This structure allows current customers, who have benefited from the use of AE's current generation fleet, to bear some of the cost responsibility of the decommissioning expenses associated with those

[37] Categorizing decommissioning expense as an O&M expense is also how AE funded the decommissioning of the Holly Street Power Plant.

assets. For these reasons, Austin Energy requests that the IHE recommend that Council adopt the decommissioning reserve levels proposed by Austin Energy.

C. Internally Generated Funds for Construction

Austin Energy finances its CIP through a combination of debt and equity, with the equity portion derived from AE's current year net revenues. Internally Generated Funds for Construction ("IGFC") is a function of CIP, contributions in aid to construction ("CIAC"), and the debt to equity financing ratio. Specifically, it is the sum of CIP, net of CIAC, financed with Net Revenues plus CIAC. This is depicted in the following formula: [(CIP – CIAC) x equity financing ratio] + CIAC = IGFC. Financial Policy No. 12 governs AE's treatment of IGFC. It states:

> Net Revenue generated by Austin Energy shall be used for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies, and other Austin Energy requirements such as working capital.[38]

AE included $88,341,455 of IGFC in the test year. This amount was calculated as follows:

> $158,169,688 CIP - $18,513,221 CIAC = $139,656,467 CIP net of CIAC.
> $139,656,467 CIP net of CIAC x 50% equity financing = $69,828,233 net revenue funded.
> $69,828,233 net revenue funded + $18,513,221 CIAC = $88,341,455 IGFC

NXP/Samsung Witness Fox recommends only $50,000,000 be allowed for IGFC. This represents a $38,341,455 decrease to AE's request. NXP/Samsung's recommendation is derived by reducing the CIP amount to $125,000,000 and increasing the amount of debt financing to 60% (i.e., equity financing of 40%).[39]

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[38] AE Ex. 1 at 369 (Appendix D).

[39] Corrected Direct Testimony of Marilyn Fox, NXP/Samsung Ex. 1 at 19:15-17.

In order to arrive at their recommended $125,000,000, Ms. Fox excludes power production CIP. Ms. Fox argues that although AE will incur power production CIP, none should be included in the rates because City Council has not determined AE's next incremental power supply, such as constructing a power plant or entering a power supply contract.[40] Ms. Fox's illogical recommendation fails to account for the fact that Austin Energy has existing power production assets that require CIP investment. This is demonstrated on WP C-3.4.1 of the cost of service model. For example, from Fiscal Year ("FY") 2012 through FY 2015, AE has invested an average of $21 million per year in CIP on its existing power plants. Austin Energy has shown that power production CIP is incurred annually and is not contingent upon City Council approving AE's next incremental power supply project. City Council approves the 5-year CIP, which includes the power production spending. Therefore, NXP/Samsung's recommendation to exclude power production CIP is unreasonable.

The test year CIP is set at FY 2015 historical costs and equals $168 million, which includes $10 million in non-electric costs that are excluded from the IGFC calculation. The FY 2015 CIP is a reasonable proxy for AE's expected CIP. This is demonstrated by the fact that it is within 3% of AE's average CIP amount for the years FY 2012 through FY 2014.[41] In contrast, NXP/Samsung's $125 million recommended CIP is 24% below the average CIP level of $164 million experienced in the years FY 2012 to FY 2015.[42] AE's historical CIP for the years FY 2012 through FY 2015 is as follows: FY 2012 = $166 million, FY 2013 = $155 million, FY 2014 = $167 million, FY 2015 = $168 million.[43] This data demonstrates a consistent

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40 *Id*. at 20:13-15.

41 AE Ex. 2 at 19:20-21.

42 *Id*. at 19:21-20:2.

43 *See* AE Ex. 1 at 831 (WP C-3.4.1, line 13).

pattern of total CIP spending, which is stable over the 4-year period. While projects that AE works on vary by year, the total CIP amount is consistent, as noted in WP C-3.4.1.

NXP/Samsung proposes, "that AE look back several years in order to assess what AE's 'normal' level of construction expenditures is."[44] This is what AE did. Prior to selecting FY 2015 as the appropriate basis for establishing the CIP amount, AE reviewed the previous three years of expenditures in order to validate the test year amount. As noted above, AE has been remarkably consistent in the amount it spends on CIP the past four years, including in the test year.

In his rebuttal testimony, Mr. Dombroski identified additional reasons that support using the FY 2015 CIP amount. Specifically, Mr. Dombroski pointed out that Austin Energy amended its line extension policy to recover the full cost of extensions based on estimated construction costs.[45] The amended policy generated increased CIAC that reduces the revenue requirement.[46] Fiscal Year 2015 was the first complete year the amended policy was in place.[47] Consequently, AE found it reasonable to include the results from the policy and to match them to the same period, FY 2015, CIP costs.

Austin Energy finances its CIP through a combination of debt and equity, with the equity portion derived from AE's current year net revenues. For purposes of determining the appropriate amount to be recovered in rates, AE relies upon a 50% equity financing ratio. This amount is reasonable because it is well within the range prescribed by Financial Policy No. 14 that states, "[c]apital projects should be financed through a combination of cash, referred to as pay-as-you-go financing (equity contributions from current revenues), and debt. An equity

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[44] NXP/Samsung Ex. 1 at 19:9-10.

[45] AE Tr. 2 at 20:16-17.

[46] *Id*. at 20:17-18.

[47] *Id*. at 20:18-19.

contribution ratio between 35% and 60% is desirable."[48] Additionally, 50% is representative of AE's debt to equity ratio and historical average equity financing of 51% from FY 2012 through FY 2014. Finally, AE's recommended 50% equity financing complies with City Ordinance No. 20120607-055, which directs City Council to adopt a policy of targeting debt-to-equity ratio of 60/40 until October 1, 2014, and then reaffirms a 50/50 split thereafter.

In contrast to AE's proposal, NXP/Samsung recommends using a 40% equity financing ratio. In other words, NXP/Samsung recommends that AE reduce rates in the short term by incurring more debt to fund capital projects. NXP/Samsung based the 40% ratio on the assumption that it corrects AE's use of cash funding in the prior years. NXP/Samsung arbitrarily recommends 40% but offers no evidence that it is reasonable or that the historical level of equity funding is unreasonable. It is unreasonable to apply a system level debt to equity financing ratio to sub-level CIP because not all projects avail themselves to the same level of debt to equity financing. For example, certain types of capital projects, such as vehicles, are funded completely by IGFC, where it is not practical to incur 30-year bond debt for shorter life assets. Financial Policy No. 1 notes that the term of debt should generally not exceed the useful life of the asset.[49] As shown in AE's COS model on WP C-3.4.1, three-year average equity financing is 51%, which is calculated by dividing line 56 by line 13 for the respective years 2012 through 2014. Moreover, NXP/Samsung ignores that additional costs are associated with incurring more debt.

In their brief, NXP/Samsung unsuccessfully argues that netting out CIAC *prior* to multiplying the CIP sum by the 50% equity financing amount obfuscates the issue by producing a higher effective level of equity sharing (i.e., 56%). This in turn, according to NXP/Samsung, improperly inflates rates. Although NXP/Samsung's addition is accurate, they are the ones that are confusing the issue. CIAC are contributions from customers for CIP projects and, as such,

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[48] AE Ex. 1 at 369 (Appendix D).

[49] *Id*. at 368 (Appendix D).

are properly matched to CIP prior to applying debt/equity financing ratio. These contributions serve as an offset to revenues and reduce rates. This separate source of revenue must be subtracted before determining the debt/equity financing share. It is simply inappropriate to include CIAC in the calculation as prescribed by NXP/Samsung.

At City Council's direction, AE has implemented a new CIAC policy (i.e., full cost recovery) in an effort to have growth pay for itself. The direct application of that policy is to net CIAC to CIP as AE has done. Costs incurred by new customer growth are paid for by those customers through the application of CIAC. Consequently, the amount of CIP that has to be financed through rates is reduced. AE's method holds ratepayers harmless as to the costs of customer growth. The intent of the debt/equity share is to allocate funding sources of AE's net cost, regardless of the level of CIAC funding. Additionally, NXP/Samsung failed to take into account the costs associated with increased debt. These costs, of course, will ultimately be paid for by customers through rates.

Although they did not address IGFC in their direct case, the ICA adopts a "compromise adjustment" of $6 million in their brief.[50] While the ICA adds back the $21 million in production plant expenditures Ms. Fox disallowed into the CIP sum, he nevertheless disallows $12 million by normalizing the past four years of expenditures. As noted above, AE's historical CIP for the years FY 2012 through FY 2015 is as follows: FY 2012 = $166 million, FY 2013 = $155 million, FY 2014 = $167 million, FY 2015 = $168 million.[51] As such, there is no objective basis for normalizing the past four years as the ICA proposes.

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[50] ICA Brief at 15.

[51] *See* AE Ex. 1 at 831 (WP C-3.4.1, line 13). The test year CIP amount of $168 million includes $10 million in non-electric costs that are excluded from the IGFC calculation.

D. Transmission Costs and Revenues

According to NXP/Samsung, Austin Energy has $14,479,686 in "excess recovery of Austin Energy's PUC approved wholesale transmission revenue" that should have been applied to the base rate revenue requirement.[52] This would be offset, in part, by a $10 million increase in transmission expense associated with AE's payments to other transmission service providers for use of the transmission system. Despite strenuous advocacy, lengthy discussion in their brief, and sharp allegations, NXP/Samsung's discussion of transmission costs and revenues reflects a fundamental misunderstanding of ratemaking principals and the law.

Under Texas law, the PUC has exclusive authority to regulate transmission service.[53] As such, City Council does not have the legal authority to require wholesale transmission customers to subsidize AE's retail operations. Specifically, the Public Utility Regulatory Act ("PURA") §§ 35.004(b) and (c) applies to the provision of transmission service. For purposes of this provision, the term "electric utility" includes a MOU.[54] Section 35.004(b) provides in relevant part:

> The commission shall ensure that an electric utility or transmission and distribution utility provides nondiscriminatory access to wholesale transmission service […to…] other electric utilities or transmission and distribution utilities.

In addition, Section 35.004(c) states:

> When an electric utility, electric cooperative, or transmission and distribution utility provides wholesale transmission service within ERCOT at the request of a third party, the commission shall ensure that the utility recovers the utility's reasonable costs in providing wholesale transmission services necessary for the transaction from the entity for which the transmission is provided so that the utility's other customers do not bear the costs of the service.

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52 NXP/Samsung Brief at 15.

53 Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 35.004, 35.005 (West 2007) (PURA).

54 PURA § 35.001 (West 2007).

These provisions make it clear that a transmission service may not subsidize a MOU's retail function. In addition, 16 Tex. Admin. Code § 25.275(o)(1)(C) provides:

> Provisions for Bundled MOU/COOPs.
>
> (C) Cross-subsidization prohibited. A bundled MOU/COOP shall not create significant opportunities for cross subsidization of competitive energy-related activities with revenues from distribution and transmission rates.

Under NXP/Samsung's recommendations, revenues from transmission rates would be cross subsidizing AE's generation activities (i.e., retail rates include generation costs) which are competitive energy-related activities.[55] This plainly violates the PUC's rule.

Furthermore, it is bad policy to set retail rates arbitrarily lower based upon wholesale transmission revenues at a given point in time. As soon as utility rates are set by the regulator, the revenues and expenses of the utility vary from those approved. The fact that transmission revenues are different than the amount approved in the last case does not mean that a transmission service provider ("TSP") has "excess revenues" or is over-earning. In the event that the City of Austin were to set retail rates lower than AE's cost of service, the PUC would undoubtedly require AE to adjust the rates to ensure that its wholesale transmission customers (i.e., distribution service providers ("DSPs") in ERCOT who pay the "postage stamp" rate to TSPs for use of the transmission system) are not subsidizing those rates. Contrary to NXP/Samsung's assertions, AE cannot simply transfer dollars from one "bucket" to the other.

[55] AE assumes that if adopted, NXP/Samsung's proposal would be applicable both ways. That is, NXP/Samsung would support retail customers subsidizing the transmission function if it becomes necessary to increase transmission rates.

Transmission by Others – FERC Account 565

NXP/Samsung recommends an adjustment to retail transmission costs included in FERC Account 565 using the 2016 postage stamp rate approved in PUC Docket No. 45382[56] and based on AE's most recent average ERCOT 4 Coincident Peak ("CP"). Specifically, Ms. Fox testified that "AE should use the most recent PUC approved statewide postage stamp rate and that this rate should be assessed against AE's most recent 4CP."[57] Although this adjustment would increase the regulatory charge recovery when it is adjusted during the upcoming budget process, AE does not support this proposal at this time.

Mr. Maenius provided testimony on this issue. He noted that the postage stamp rate recommended by Ms. Fox was approved in PUC Docket No. 45382 on March 25, 2016, well after the rate RFP had been developed and released. Mr. Maenius also pointed out that Ms. Fox's recommendation is beyond the scope of this base rate case and inappropriately extends the historical test year. Ms. Fox also recommends applying the postage stamp rate against AE's most recent 4CP, an action that would create a mismatch for transmission cost bill determinants as compared with the determinants used in the normalized 4CP included in the test year. Lastly, this change is beyond the scope of this case insofar as it does not impact base rates. For these reasons, Ms. Fox's proposal should be rejected.

Transmission Other Revenue

At page 23 of their brief, NXP/Samsung state that "Mr. Maenius and Austin Energy must be under some illusion that Austin Energy is an unbundled utility holding company, consisting of regulated and unregulated affiliates governed by PUC affiliate transactions rules and a code of

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[56] *Commission Staff's Application to Set 2016 Wholesale Transmission Service Charges for the Electric Reliability Council of Texas*, Docket No. 45382 (Mar. 25, 2016).

[57] NXP/Samsung Ex. 1 at 23:14-15.

conduct."[58] They go on to state their "belief" that AE "demonstrates a serious lack of understanding of generally applied and approved ratemaking principles, especially as these principles relate to municipally-owned utilities."[59] These are bold words for a party that is wrong.

Like many utilities in the state, AE has a transmission business and a retail business. Thus, AE is both a TSP and a Load Serving Entity ("LSE"). AE could divest itself of their entire transmission business and still be a LSE. Similarly, it could sell off its entire retail customer base and remain as a TSP. These are two separate functions with two sets of customers and two revenue streams. The revenue associated with transmission assets comes from one set of customers while the revenue from the ownership of retail assets comes from another set of customers.[60] If AE were to sell either of these systems, they would continue to have the same revenue stream from the other system. This structure is common and well known in Texas.

Similarly, there is a difference between retail transmission expense and wholesale transmission costs. AE's retail transmission expense is the cost born by AE's retail customers and paid to other TSPs in the ERCOT region. The retail transmission expense is the product of the PUC-approved statewide transmission postage stamp rate and AE's average ERCOT 4CP. These costs are coded to FERC Account 565 and are recovered from AE's retail customers through the Regulatory Charge. AE's wholesale transmission costs, on the other hand, are AE's costs of owning and operating its transmission assets as part of the ERCOT transmission grid. AE recovers its wholesale transmission costs, such as transmission O&M or transmission asset

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[58] NXP/Samsung Brief at 23.

[59] *Id.*

[60] NXP/Samsung's claim at page 25 that AE has no "wholesale customers" is also wrong. Wholesale transmission customers are all of the DSPs who pay transmission revenues to AE and the other TSPs in the state. The IHE can be certain that the PUC knows who these customers are and will ensure that they are not subsidizing AE's retail operations.

debt service, from other DSPs at AE's PUC-approved transmission cost of service ("TCOS") rate. Revenue received to cover AE's wholesale transmission is the product of AE's TCOS rate and the average ERCOT 4CP. Wholesale transmission costs and retail costs are separate and distinct, recovered from two different customer bases, and under different jurisdictional ratemaking regulatory bodies. Consequently, the wholesale transmission function and the retail function should not subsidize each other. Keeping retail costs and revenues separate from those of AE's wholesale transmission function ensures that each set of customers only pays for the cost to provide the respective service.

Including costs or revenues from one function in the other's revenue requirement violates two basic rate making principals: cost causation and cross subsidization. Consequently, AE has adjusted the transmission costs in the retail case to include only those costs applicable to the retail function and excluded costs associated with the wholesale function which are recovered from ERCOT's DSPs. Retail transmission costs are recorded in FERC 565 and affirmed in NXP/Samsung's testimony.[61]

As previously stated, AE made specific adjustments to the revenue requirement in order to exclude wholesale transmission costs and leave only retail transmission (matrix expense) recorded in FERC 565. Wholesale transmission revenue is set so that mathematically, the only remaining transmission expense included in the retail revenue requirement is the retail transmission expense in FERC 565, as shown at line 36, Column L, in Schedule A. The calculation is repeated below for clarity:

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[61] Rebuttal Testimony of Russell H. Maenius, AE Ex. 8 at 8:3-9.

Description	Schedule A, Column L	Retail	Reference	Wholesale
Non-Fuel O&M	145,698,897	116,855,952	Sch D-1, Col L, Line 88	28,842,945
Depreciation & Amortization	16,333,280			16,333,280
Total Expenses (before Return)	162,032,176	116,855,952		45,176,225
Return				
Debt Service	17,933,287			17,933,287
General Fund Transfer	7,561,714			7,561,714
Internally Generated Funds for Construction	10,364,686			10,364,686
Sub-Total	35,859,686			35,859,686
Less:				
Depreciation & Amortization	(16,333,280)			(16,333,280)
Interest and Dividend Income	(890,025)			(890,025)
Sub-Total	(17,223,305)			(17,223,305)
Cash Flow Return Requested	18,636,382			18,636,382
Total Cost of Service	180,668,558	116,855,952		63,812,606
Less Other (Non-Rate) Revenue	(63,812,606)			(63,812,606)
Total Retail Electric Revenue Requirement	116,855,952	116,855,952		
		FERC 565		

NXP/Samsung's position is that wholesale transmission revenues should subsidize the retail function so that retail customers do not incur the true costs to serve. NXP/Samsung propose to do this by increasing "Other Revenue" to reflect AE's wholesale transmission revenues set in Docket 45382 in the amount of $76,609,599. Consequently, NXP/Samsung seeks to include wholesale transmission costs and wholesale transmission revenues in the retail rate case. However, if NXP/Samsung insist on including the full measure of AE's wholesale transmission revenues, then it is appropriate that the full measure of AE's wholesale transmission costs also be encompassed, including the wholesale transmission return authorized by the PUC.

Wholesale transmission revenue has a higher embedded PUC approved return than what is included in the retail case and should be recognized to match revenues to cost of service.

Description	Modified Schedule A, Column L	Retail	Wholesale
Non-Fuel O&M	145,698,897	116,855,952	28,842,945
Depreciation & Amortization	16,333,280		16,333,280
Total Expenses (before Return)	162,032,176	116,855,952	45,176,225
Return	18,636,382		18,636,382
Additional Return Authorized by PUCT (Note 1)	**37,323,872**		**37,323,872**
PUCT Approved Wholesale Return	**55,960,254**		**55,960,254**
Total Cost of Service	217,992,430	116,855,952	101,136,478
Less Other (Non-Rate) Revenue	(63,812,606)		(63,812,606)
Additional Wholesale Revenue (Note 2)	**(14,479,680)**		**(14,479,680)**
Total Other (Non-Rate) Revenue	**(78,292,287)**		**(78,292,287)**
Total Retail Electric Revenue Requirement	139,700,144	116,855,952	22,844,192
		FERC 565	
Note 1			
Schedule B, Col L, Line 14 (Transmission Rate Base)			372,819,810
Authorized PUCT Wholesale Transmission Return (Docket 42385)			15.01%
Wholesale Transmission Return			55,960,254
Note 2			
Wholesale Transmission Revenue (WP E-5.1.1, Col C, Line 4)			62,129,919
Wholesale Matrix Revenue, Docket No. 45382			76,609,599
Additional Wholesale Transmission Revenue			(14,479,680)

Austin Energy is under-recovering on its wholesale transmission function by $23 million. By incorporating wholesale transmission costs and revenues into the retail case, as opposed to AE's position of eliminating wholesale transmission costs from the retail case, retail customers would be subsidizing AE's wholesale transmission function by $23 million.

Schedule A, Col L, Line 36	$116,855,952	Equals FERC 565 Amount
Additional retail revenue to subsidize wholesale function	+$22,844,192	
Modified Sch A to include all transmission wholesale costs/revenues	$139,700,144	

Fundamentally, NXP/Samsung confuses retail transmission expense with wholesale transmission costs and revenues. This results in subsidization by using the wholesale transmission revenues AE receives from DSPs within ERCOT that were approved by the PUC to cover costs properly incurred by AE's retail customers. It is illegal, bad public policy, and politically unwise to establish Austin Energy's retail base rates based upon assumptions about Austin Energy transmission function. For these reasons, NXP/Samsung's proposal must be rejected.

E. FPP Debt Defeasement

PC/SC proposes establishing a fund to defease the debt associated with Austin Energy's share of the FPP.[62] PC/SC's rationale for creating a new source of funds is to ensure AE's share of FPP is retired pursuant to the timetables outlined in the *Austin Energy Resource, Generation, and Climate Protection Plan to 2025* ("Gen Plan").[63] Establishing the debt defeasance fund, according to PC/SC, would enable AE to pay off the long-term FPP debt early and help AE avoid a significant rate increase in the future. However, adoption of PC/SC's recommendation would increase rates now by an amount between approximately $24 million and $31 million annually.[64] AE does not support this proposal for several reasons.

[62] PC/SC Brief at 7.

[63] Austin Energy Resource, Generation and Climate Protection Plan to 2025: An Update of the 2020 Plan, PC/SC Ex 4.

[64] PC/SC Brief at 10. The range depends on the total amount of debt to defease and the amortization period of defeasance.

First, the Gen Plan is a City Council-approved strategic document which guides AE's near- and mid-term operational planning. City Council reviews and updates this document every two years, using the latest set assumptions and information to make decisions that best reflect, and carefully balance, a dynamic series of community goals, financial policies, operational limitations, and administrative needs. The Gen Plan does not specifically authorize any individual action; instead, it guides AE staff in making operational decisions for the next three to five years. For example, even though the Gen Plan set out targets for acquiring additional utility scale solar capacity, AE staff was still required to seek City Council authorization to negotiate and execute contracts that enabled AE to meet those goals. Similarly, even though the Gen Plan calls for the operational ramp down of FPP to start in 2020, this goal does not specifically authorize AE to enter into an agreement with the Lower Colorado River Authority ("LCRA") to change the joint participation agreement. AE would first need to present that agreement to City Council for its approval.

Because the target date of 2020 is a target, many factors could change between today and 2020 which might influence Council's ultimate decision to start ramping down operations. Further analysis is required and is being conducted before Council can make a prudent decision on how and when to start ramping down FPP. This does not imply that AE is ignoring the Gen Plan; on the contrary, internal planning is currently underway in an effort to analyze the myriad inputs that can affect resource planning initiatives. In the end, though, individual resources decisions must be examined in the greater context of AE's operations and City Council goals, and the Gen Plan does not represent the pinnacle of that analysis. It instead is the guide that leads AE to analyze many alternatives and ultimately make decisions or recommendations on how best to achieve the goals laid out in the Gen Plan. Elements that must be considered in this deeper analytical context include:

- <u>Operational risk</u>: Closure of AE's share of FPP would increase the unhedged market risk of AE's customers, exposing customers to future volatile market prices. Additionally, ERCOT may require AE to maintain operations of its share of FPP until a transmission security plan is developed and implemented.

- <u>Financial risk</u>: Assuming AE decommissioned, or otherwise shutdown, half of the capacity of the FPP Units 1 and 2, significant and ongoing costs would continue, without any offsetting revenue from power and energy sales, unless the participation agreement with LCRA is renegotiated.

- <u>Legal risk</u>: Defeasance of the bond debt prior to the date the debt actually becomes callable would pose legal risks. This action would likely face a legal challenge because AE does not have the legal right to redeem or defease the bonds until the call date. Additionally, AE may not unilaterally make decisions for FPP operations: LCRA is the operating partner of the plant and has legal rights that must be respected.

- <u>Policy risk</u>: a premature decision to retire FPP might negatively impact the City's affordability goals. For example, PC/SC's proposal could effectively eliminate the entire system-wide rate decrease AE has proposed in this case.

There are benefits associated with the retirement of AE's share of FPP that must be weighed as well, but the totality of the risks and benefits must be explored in depth and a full plan must be developed and presented to City Council for its approval before it would be prudent for AE to start collecting funds associated with debt retirement.

Moreover, AE notes that while the Gen Plan is clear in its guidance to staff about preparing for the eventual retirement of FPP, the specific language in the Gen Plan also makes it clear that retirement of FPP will not occur absent consideration of other factors. As PC/SC notes in its closing brief, the Gen Plan directs staff to consider the legal, economic, and technological implications of retiring FPP.[65]

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[65] PC/SC Brief at 8.

Second, because there is no specific plan in place, the new revenue that would be collected by PC/SC's proposed fund does not meet the known and measureable test for making adjustments to historical test year costs. No party, including AE, has presented definitive testimony on what the appropriate funding level would be if this defeasance fund were to be created.[66] Consequently, fundamental ratemaking principles dictate that AE cannot make an adjustment to its revenue requirement at this time without knowing more parameters of the timing of collections and use of funds. The appropriate method would be first for City Council to approve a retirement and defeasance plan and then for AE to develop the corresponding rates to meet that plan. Until then, it would be premature to include revenues for debt defeasance in this rate review.

Third, PC/SC's logic in drawing similarities between decommissioning funds and collecting defeasance funds is fundamentally flawed. In his cross-examination by PC/SC, AE Witness Mark Dombroski stated that it does make sense to set aside money for debt defeasance in the same way that AE sets aside money for plant decommissioning:

> Because the decommissioning cost is—we are incurring that expense as we're using the plant, and so while the cash flow has not occurred yet, we are incurring the expense, we're producing power with that plant. We're also making payments according to a debt schedule that is amortized over the life of that asset. So we are paying off the debt in the same manner as we're—as we should be collecting for decommissioning, which is over the life of that asset.[67]

Similarly, AE Witness Joe Mancinelli testified to the difference between decommissioning funding and debt retirement funding:

> Well, I mean, there are, there are—they've got different issues surrounding each, each of those decisions. You can't really

[66] *Id.* at 10; Tr. at 654:12-24; AELIC Brief at 9; ICA Brief at 16-17; NXP/Samsung Brief at 27.

[67] Tr. at 608:15-24.

> commingle them. They're very different. I mean, decommissioning the Fayette plant is, is basically recognizing a liability, a future liability of, of dismantling the plant. On the other hand, Austin Energy borrows a lot of money in the market and is an active—active in the bond markets and, and defeasing debt has to be done within the legal restrictions surrounding that debt. And so they're, they're just very different things.[68]

The equivalent to collecting decommissioning costs for repayment of long-term debt is the 30-year schedule of annual principle and interest debt payments, not a mechanism to fund early repayment of that debt. Therefore, following the same logic used to justify collection of decommissioning funds to suggest the creation of an early debt retirement fund is erroneous, and the IHE should not accept it.

AE agrees with AELIC,[69] ICA,[70] and NXP/Samsung[71] that collecting revenue for a debt defeasance fund at this time would be premature because PC/SC's rationale is based on speculative activity in an unknown future. There are several steps that must be taken before rates can be established to recover the cost of retiring debt associated with FPP, including creation and approval of a full decommissioning and debt retirement plan. Until such a plan is developed, agreed to by LCRA, approved by the City Council, and assigned into operational objectives, any rate recovery would be premature. AE recommends the IHE reject PC/SC's proposal.

F. Debt Service Associated with South Texas Nuclear Project

Intervenor Robbins proposes to increase rates by accelerating the payments on AE's debt obligations associated with the South Texas Nuclear Project ("STP") to match the expiration of the current license for the plant. Mr. Robbins' recommendation is premature and should be rejected. Austin Energy owns 16% of the two units that comprise the STP. Unit 1 is currently

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[68] Tr. at 772:6-17.

[69] AELIC Brief at 8.

[70] ICA Brief at 17.

[71] NXP/Samsung Brief at 27-28.

licensed to operate until August 20, 2027. Unit 2 is currently licensed until December 15, 2028. The current debt payment schedule concludes in 2041.

As noted in Mr. Maenius' rebuttal testimony, both units of STP are in the process of being relicensed.[72] Once the licenses are granted, the current expiration dates for each unit will be extended by 40 years. Currently, the application is pending before the Nuclear Regulatory Commission ("NRC"). Accordingly, Mr. Robbins' recommendation to accelerate debt service does not meet the known and measurable test. Additionally, there are still over 11 years remaining on the current license for unit 1 and over 12 years remaining on the current license for Unit 2. Therefore, even if the NRC were to deny the license extension request, Austin Energy will have ample time to make contingency plans that will provide for full cost recovery while not unduly impacting rates. For these reasons, Mr. Robbins' proposal should be rejected.

G. Uncollectable Expense

AE presented $16,054,751 in test year uncollectable expenses,[73] an amount which incorporates a decrease of $4.8 million[74] from the actual uncollectable expense AE incurred in FY 2014. Three parties AELIC, NXP/Samsung, and the ICA recommend adjusting AE's test year uncollectible expense even lower. The ICA recommends an expense amount of $10.1 million based on a five-year average of uncollectable expenses between FY 2010 and FY 2014.[75] NXP/Samsung[76] and AELIC[77] propose that AE match the bad debt recorded in unaudited FY 2015, or $8,462,938. All three parties base their recommendations on a perceived downward trend in uncollectable expenses. AE disagrees with these recommendations because each

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[72] AE Ex. 8 at 5:10.

[73] AE Ex. 1 at 383 (Schedule D-1, Column J, Row 138).

[74] *Id*. at 093.

[75] ICA Brief at 22.

[76] NXP/Samsung Brief at 28.

[77] AELIC Brief at 13.

represents a subjective adjustment based on predictions of what may or may not occur in future years.

At their core, the parties' recommendations do not meet the known and measurable test for making adjustments to historical financial data. While the amount of uncollectable expense decreased between FY 2014 to FY 2015, and was properly recorded in AE's initial $4.8 million adjustment,[78] a single year decrease does not represent a knowable trend on which AE should make additional adjustments. In fact, a different trend may emerge in the coming year because the amount of bad debt experienced in FY 2014 is in part attributable to a more lenient payment arrangement policy approved by the Austin City Council in Fall 2013.[79] This policy change led to an increase in the total number of payment arrangements and a decrease in the number of successfully completed payment arrangements. In a May 2015 presentation to the Austin Energy Utility Oversight Committee, AE showed there were 2.7 times as many customers on payment arrangements in April 2015 than in April 2013 and that the amount due in payment arrangements had increased by 72%.[80] This data suggests that there is a distinct possibility that the level of uncollectable expenses may be on the rise again after a single year decrease.[81]

AE does not dispute the ICA's assertion that AE has far higher average bad debt expenses than other utilities across the country.[82] This fact is not, in and of itself, a reason to disallow the level of AE's test year uncollectable expenses. It simply points to a significant

[78] In part, the appropriateness of AE's $4.8 million known and measurable adjustment is attributable to the completion of three extraordinary trends that started as early as 2011. *See* Tr. at 650:7-651:3.

[79] *See* City of Austin Code of Ordinances § 15-9-144, AELIC Ex. 36 and Tr. at 867:9-17.

[80] AE Response to AELIC RFI No. 10-13, AELIC Ex. 38 at 255.

[81] AELIC Witness Lanetta Cooper offered evidence from a June 2014 presentation by AE staff to the Austin City Council in AELIC Ex. 38. However, Ms. Cooper cherry picked information from AE's complete response to AELIC's RFI Nos. 10-12 and 10-13 to support her position. Had Ms. Cooper presented additional information provided in these responses using data from a more recent presentation to City Council, such as AE's May 28, 2015 presentation, a more complete picture of AE's uncollectable expense level would have been drawn in AELIC's Closing Brief.

[82] ICA Brief at 21.

difference in policy requirements enacted by AE's governing body and the uncollectable debt level reflects the unintended results of those policies.

None of the three parties recommending changes to AE's uncollectable expenses offer evidence that would pass the threshold tests for making further known and measurable adjustments. Their arguments are based on the supposition that a single year's financial performance predicts future trends. AE's proposed $16 million of uncollectable expense is a reasonable estimation of future expenses as it reflects both historical and current trends. Therefore, the IHE should reject the proposals of AELIC, NXP/Samsung, and the ICA to further decrease the level of uncollectable expenses.

H. Economic Development and Community Programs

Austin Energy has proposed including $9,090,429 as O&M in its revenue requirement to be transferred to the City's Economic Development Department. The ICA and NXP/Samsung are the only intervenors who addressed this issue in their closing briefs. However, neither party presents compelling arguments for adjusting this expense. Thus, AE recommends the IHE approve the $9,090,429 in AE's revenue requirement for funding economic development and community programs.

Austin Energy's funding of economic development and community programs is a reasonable and necessary expenditure that helps develop a diverse system load. A diverse system load benefits all customers by improving AE's system load factor and thus reducing regulatory costs. Economic development programs also lead to a more stable and predictable system load, and increase the customer base to share AE's fixed costs.

The ICA is not recommending any disallowance of these funds.[83] The ICA is simply "recommending that these funds be treated as flowing through the General Fund Transfer

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[83] *Id*. at 24.

(‘GFT’)” for the sake of transparency.[84] Indeed, the ICA states, “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.”[85] The ICA’s recommendation is based on the position that these funds are not reasonable and necessary for providing utility service, and therefore, should be separated from AE’s COS.

NXP/Samsung also claims that AE’s economic development and community programs expenditures are “not necessary and reasonable to provide electric service and should therefore not be paid for by Austin Energy ratepayers.”[86]

However, the ICA and NXP/Samsung fail to recognize that economic development and community programs expenses *are* reasonable and necessary for providing utility service. The Economic Development Department attracts new businesses to Austin, which creates new customers for AE, and helps retain and expand existing Austin businesses, thus maintaining and increasing revenue for AE. In addition to attracting new and retaining existing commercial customers, economic development programs lead to new residential load growth. For example, the City of Austin experienced new residential load growth due to the economic development project that redeveloped the Mueller Airport into a thriving residential community of single and multifamily units. Economic development projects have also created new residential units in downtown Austin in the 2nd Street District and the redeveloped Seaholm power plant site. As of March 2012, Austin Energy’s investment in Economic Development was found to have led to

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[84] *Id*.

[85] ICA Brief at 25.

[86] NXP/Samsung Brief at 29.

the successful recruitment of major employment centers in Austin resulting in $60.1 million of electric revenue for AE.[87]

The ICA compares AE's economic development expenditures to other Texas electric utilities, claiming that AE's expenditures are greater than most and, in particular, AE's economic development of 0.77% of revenues is greater than CenterPoint's equivalent 0.16%. This comparison, however, lacks context and is not an accurate indicator of what constitutes an appropriate amount for a utility to spend on economic development. As a MOU, Austin Energy's community role and business model are completely different than a private, for-profit utility like CenterPoint. Therefore, this comparison provides no value to this proceeding and has no bearing on whether AE's economic development funds are reasonable and necessary. Indeed, the ICA seems to present the comparison for purely informational purposes as it does not recommend a disallowance of AE's economic development and community programs expenses.

Finally, NXP/Samsung also notes City Council's plan to allocate funding to the General Fund or other City departments but concedes that the 2016-17 budget is not approved and the $9,090,429 AE is requesting in this rate proceeding "represents the amount allocated to Austin Energy for the 2015-16 Budget." AE has repeatedly explained throughout this proceeding that it is not authorized to adjust the City budget. City Council sets the City budget and dictates the portion for AE. In addition, the Economic Development Department receives funding from other City departments and City-owned utilities. Concerns with how Council sets and funds the City budget, or why City departments and City-owned utilities contribute to the City's Economic Development Department, are more appropriately raised with City Council during the City budget process.

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[87] *See e.g.*, AE Supplemental Response to ICA RFI No. 6-5 (Apr. 22, 2016).

I. Loss on Disposal

Losses associated with the disposal of various assets (i.e., loss on disposal) are a common expense that is typical for electric utilities. During the test year, Austin Energy experienced $7,170,039 in such losses.[88] Because the test year amount is recurring and representative of both past and expected future experience, AE made no adjustment to the test year amount. Notwithstanding that this is a recurring expense and that the test year amount is typical of past experience, NXP/Samsung Witness Fox recommends excluding the entire requested amount for loss on disposal. In support of her position Ms. Fox states that the test year "is not known and measurable"[89] and "since AE is using a cash flow method to determine return, the book loss should not be included."[90]

NXP/Samsung admits that the test year amount is the actual FY 2014 loss on disposal. However, they seek to remove it because the historical amount is not known and measureable. This is unreasonable. The historical test year amount is a known quantity. NXP/Samsung cannot assert that the loss is non-recurring because their testimony states that losses occur yearly.[91] In fact, the test year amount is actually lower than the amount experienced by AE in two of the three years prior to the test year.

Even if one assumes that Ms. Fox intended to say that it is unknown whether the expense will occur in the future, her recommendation fails. Past experience, as well as Mr. Dombroski's testimony that this is a recurring expense, demonstrates that this is an appropriate expense to include in rates. Ms. Fox's logic is that unless the future can be accurately predicted, any cost should be eliminated from rates. Respectfully, that is not how electric rates are set. Because the

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[88] The test year amount is the historical FY 2014 book amount, as shown on line 6 in AE Ex. 1 at 901 (WP E-4.3).

[89] NXP/Samsung Ex. 1 at 34:2-3.

[90] *Id.* at 34:5-6.

[91] *Id.* at 34:11-13.

test year amount is representative of past experience and what is expected to occur in the future, it is reasonable to include that amount in rates.

Ms. Fox also claims that the loss on disposal should be disallowed because AE used the cash flow method to determine its return. This argument is unreasonable. As noted in Mr. Dombroski's rebuttal testimony "[l]oss on disposal is not an element of the return function."[92] Therefore, the method used to determine AE's return is irrelevant to the loss on disposal, just as it would be irrelevant to any O&M cost. The cash flow method only pertains to those elements noted in the return function and listed in Schedule C-3.

Although the ICA took no position on this issue in their testimony or at the hearing, in their brief, they change course and propose an $800,000 adjustment. This adjustment, presented for the first time in brief, is based upon taking the losses for the three years prior to the test year (i.e., 2011-2013) and normalizing "these three years of experience."[93] As written, it appears that the ICA is proposing to ignore the test year amount and then average the three prior years. Of course, there is no way to know if that is what is intended because the parties have not previously seen this recommendation. More importantly, by including the exceptionally and anomalously low loss amount for 2013, the ICA inappropriately disallows the reasonable and anticipated amount to cover losses on asset disposal.

Austin Energy has included in its cost of service the actual amount of losses experienced during the test year. This is the most accurate accounting of this recurring expense and Austin Energy requests that the IHE recommend that Council accept this amount and not make any of the adjustments suggested by NXP/Samsung or the ICA.

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[92] AE Ex. 2 at 28:17.

[93] ICA Brief at 27.

J. Customer Care

Both the ICA and NXP/Samsung propose that a different cost allocation method be used to assign costs related to the AE-operated Utility Customer Center ("UCC") to the other City utilities and departments that use the UCC's services.[94] The effect of using the recommended alternative cost allocation method would effectively reduce AE's revenue requirement by approximately $10.3 million.[95] Austin Energy disagrees with these proposals and requests that the IHE recommend to Council that the current allocation method continue.

AE operates the UCC on behalf of the City, specifically serving the departments and customers of Austin Water Utility ("AWU"), Austin Resource Recovery ("ARR"), the Transportation Department, the Watershed Protection Department, and various other smaller departments.[96] The UCC serves as the primary place for customers to report electrical outages.[97] Additionally, the UCC provides and maintains the automated utility customer management call center, meter reading, and billing system.[98]

The complex billing system captures account information and premise information, ultimately generating customer bills that include charges for metered services such as electric (AE) and water and wastewater (AWU), garage carts based on size for ARR, and a drainage fee.[99] Bills also include miscellaneous fees and charges, such as initiation of service fees, late payment fees, and extra garage bag fees.[100] Finally, the bill also includes pre-determined monthly fees for other non-metered services provided by the City.[101]

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94 *See* NXP/Samsung Brief at 30-31 and ICA Brief at 27-28.

95 ICA Brief at 27, fn. 87.

96 *See* AE Ex. 2 at 30:9-12.

97 *See* Tr. at 231:5-21.

98 *See* AE Ex. 2 at 30:12-14.

99 *Id*. at 30:18-20.

100 *Id*. at 30:20-22.

101 *Id*. at 30:22-23; *see also* Tr. at 224:1-9.

AE allocates the costs related to the UCC in accordance with the model developed by KPMG.[102] AE and the City have successfully used this model, created by an independent consulting expert, for the past 14 years and it was approved by City Council in the last AE rate review.[103] Development of this model required extensive research to determine the appropriate basis for each allocation. In contrast, Ms. Fox's allocation method was based solely on her personal judgment calls and her knowledge of what utilities Austin has.[104] While NXP/Samsung and the ICA may consider the allocation method devised by Ms. Fox appropriate for their purposes, it does not render AE's allocation unreasonable.

Suggestions by NXP/Samsung and the ICA that a different allocation method is more appropriate ignores the cost drivers underlying the specific allocation factors used in the KPMG model. For example, NXP/Samsung asserts that the "Customer Billing" and "Revenue Measurement and Control" organizations should be allocated based on the total number of bills, rather than only the bills for electric, water, and wastewater. However, the current allocation model appropriately attributes the costs related to these functions directly to the City's metered utilities because of the need to validate bills against the plethora of utility rates and tariffs. Therefore, it would be inappropriate to allocate these costs to non-metered utilities.

NXP/Samsung's proposal, as advocated for by the ICA, is also flawed because it incorrectly implies that a department such as ARR and Austin Energy are responsible for a similar share of the costs, including the costs of the billing system. In fact, the complexity of the electric billing system is significantly greater than the billing system for solid waste disposal. As a result, NXP/Samsung's suggestion that ARR and AE are equally responsible for the operation

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[102] *Id.* at 30:1-6.

[103] *Id.* at 30:4-6.

[104] *See* Tr. at 422:24-423:23.

and maintenance of the Customer Care and Billing ("CC&B") system is inconsistent with cost causation principles.

NXP/Samsung's proposed allocations inappropriately shift electric costs to other City departments, but lack any specific support for the adjustments. Moreover, using the NXP/Samsung allocation method would lead to inappropriate increases to the customer bills of those departments. While NXP/Samsung asserts that the IHE should ignore those increases because this is a proceeding to address electric rates, this shortsighted approach fails to acknowledge the cost causation issues discussed herein.

Because the KPMG allocation model used by the City of Austin properly allocates costs to the impacted city departments and represents an appropriate and reasonable balancing of related benefits and burdens, AE requests that the IHE recommend that City Council continue using it.

K. Rate Case Expense

Austin Energy proposes to collect $1,757,931 in rate cases expense over a three year amortization period (i.e., $585,977 x 3 years = $1,757,931). Although no party challenged the reasonableness of the requested amount, NXP/Samsung Witness Fox recommends changing the amortization period from three to five years. This translates into a $215,333 reduction to AE's revenue requirement. This recommendation is based on the current requirement that AE conduct a cost of service study at least every five years. In their brief, 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 it next rate review."[105]

As noted in Mr. Dombroski's rebuttal testimony, a three year amortization is typical of the period over which other utilities collect rate case expenses. This is reasonable because it

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[105] ICA Brief at 29.

balances the interests of the utility in obtaining cost recovery and the interests of ratepayers by mitigating rate impacts and spreading the cost over the period that rates are likely to be in effect. This is important because AE's proposal avoids expense recovery from one proceeding overlapping with the recovery of expenses from a subsequent rate case. This is particularly important for AE because, although it has a financial policy to conduct a cost of service study at least every five years, the policy does not prohibit AE from conducting one on a shorter time frame. Indeed, ICA Witness Johnson proposes that AE conduct cost of service studies more frequently than the five years prescribed in the financial policy.[106] For these reasons, a three year amortization period for rate case expenses is the most appropriate and should be adopted.

L. Outside Services

Austin Energy has historically relied upon outside consultants and experts to assist it with projects where it either does not have the specific expertise to complete the project or requires additional personnel.[107] Instead of incurring the permanent cost of hiring such individuals, AE engages outside experts to supplement their staff. In this manner, AE reduces overall costs and does not duplicate effort. Notwithstanding these facts, NXP/Samsung recommends eliminating the entirety of AE's outside IT support. This translates into a $6,762,767 adjustment. The basis for the recommended disallowance is AE's response to NXP/Samsung RFI No. 4-29,[108] where AE stated it has not estimated the cost for IT Staff Augmentation during the time that base rates from this proceeding will be in effect, beginning in January 2017. Consequently, NXP/Samsung posits that the entire amount should be removed because it is not known and measureable.

However, the reason AE could not estimate the costs for IT Staff Augmentation was because the City Council has not yet approved AE's FY 2017 budget, which typically occurs in

[106] ICA Ex. 1 at 101.

[107] Tr. at 148.

[108] AE Response to NXP/Samsung RFI No. 4-29 (Mar. 28, 2016).

September each year. The estimated cost will be included in Austin Energy's FY 2017 budget. The test year amount of $8.9 million for outside staff, which included the amount disallowed for outside IT staff, was the FY 2014 historical amount. AE incurred $10.1 million in costs for outside IT staff in FY 2015. This indicates a recurring pattern of IT spending on Federal Compliance Initiatives, Maintenance Activities, IT Security, and Supplemental Technology Operations. Known future projects include an upgrade of the CC&B billing system as well as a transition from IBM to Oracle as the billing system administrator. Austin Energy will strategically hire outside assistance with these projects.

In summary, a review of the past several years as well as the current approved budget demonstrates that IT Staff Augmentation costs are continuing and increasing. As such, the historical test year amount is not only representative and recurring, but also less than what AE expects to spend on these services in the future.

M. Reserves

1. Reserve Funding

Austin Energy relies on cash to fund its annual operations and in the long-run, the utility needs enough cash on hand to meet annual cost obligations, debt service requirements, and infrastructure investment needs. Unlike Investor Owned Utilities ("IOUs"), which can draw from equity and debt capital markets, MOUs, like Austin Energy, can only access cash from its reserves or issue short-term debt to secure cash for operations. As a result, adequate cash reserves are critical to the successful management of the utility.

City of Austin Financial Policies Nos. 11, 15, and 16 govern the type of and funding requirements for AE's cash reserves and are used to determine the appropriate funding levels in the COS model.[109] In order to calculate the amount of revenue required to meet City financial

[109] AE Ex. 1 at 369-70.

policies, Austin Energy compared the FY 2015 ending balances with the target funding level for each reserve. At the end of FY 2015, unaudited unrestricted reserves totaled $402,428,053. Existing financial policies require a total of $437,200,161, based on Test Year ("TY") 2014 data. Details of these calculations are shown below:

Reserve Fund	**Unaudited FY 2015 ($)**	**TY 2014 Target Amount ($)**	**Difference** *(Over)/Under*
Working Capital	251,115,560	70,080,491	(181,035,069)
Strategic Reserves			
Contingency	58,742,838	93,440,655	34,697,817
Emergency	93,490,237	93,440,655	(49,582)
Rate Stabilization	-	107,412,480	107,412,480
Repair & Replacement	64,071	72,825,880	72,761,809
Mark to Market Adjustment[(1)]	(984,653)	-	984,653
Total	**402,428,053**	**437,200,161**	**34,772,108**
Total amortized over 3 years			**11,590,703**

(1) Because FY 2015 data is unaudited, an adjustment is made to reflect the true market value of the funds. Once the audit is complete, each fund will be adjusted accordingly.

Because AE proposes to reach full reserve fund levels over three years, recovery of the funding deficiency results in an $11.6 million known and measurable increase to the annual revenue requirement.

No party disagreed with the revenue requirement associated with funding reserves under current financial policies in their closing briefs.[110] With this in mind, AE recommends the IHE adopt AE's requested revenue requirement, which is based on current financial policy, to fully fund its reserves over three years. However, Austin Energy has an alternative reserve fund policy proposal based on recommendations made from NewGen's thorough study of AE reserve

110 Two parties did, however, offer different recommendations based on AE's alternative reserve fund policy proposal, detailed in subsection 2.

fund policies, which will be outlined in subsection 2 below. AE suggests the IHE and City Council review this alternative proposal along with the comments of intervening parties to determine whether or not a change to existing financial policies is warranted.

2. Policies

As directed by City Council in the 2012 rate ordinance, Austin Energy commissioned an independent study on the adequacy and use of its cash and reserves. Austin Energy retained NewGen to review and examine AE's reserve funds, including an overview of supporting financial policies.[111] A copy of the final result is included as Appendix I to AE's Tariff Package.[112]

Specifically, NewGen evaluated the intended purpose of each fund, compliance with reserve funding requirements per AE's financial policies, historical use of funds, and industry acceptance and appropriateness of reserve fund types and funding levels. Based on the results of these analyses, AE asked NewGen to explore structural and funding level changes that might help AE align its reserve funds more closely with industry best practice and City Council-approved goals. Based on the conclusions of the study and on AE's internal deliberations, AE recommends City Council consider revising the City's financial policies as follows:

1. Austin Energy's total unrestricted reserves, excluding the Non-Nuclear Decommissioning Reserve and the CIP Fund, should meet or exceed 150 Days Cash on Hand ("DCOH"). Cash reserves at this level will help AE maintain its AA- credit rating and may help AE achieve a AA credit rating, a key strategic goal for the utility. This targeted level of liquidity is more consistent with, but still lower than, the reserves levels of other AA rated municipal utilities.

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[111] AE Ex. 1 beginning at 427.

[112] In this study, NewGen was directed to examine the Working Capital Reserve, the Strategic Reserve, the Repair and Replacement Reserve, the Capital Improvement Plan Fund, and the Non-Nuclear Decommissioning Reserve. The Nuclear Decommissioning Reserve was excluded because its policies and minimum requirements are established by the Nuclear Regulatory Commission and are outside the purview of Austin Energy and the City Council.

2. For the internal setting of target reserve amounts, the Non-Nuclear Decommissioning Reserve should be excluded from the 150 DCOH calculation, as these reserves are set aside for the long-term to achieve a specific purpose. Also, the CIP Fund is earmarked for specific capital projects. Therefore, these reserves should be excluded from the DCOH calculation when establishing fund balances in other reserves. This appears to be consistent with the treatment by rating agencies based on a review of their calculated DCOH.

3. Reserve policies and funding levels should be modified in the following manner:

    a. Working Capital Reserve – As currently formulated, Austin Energy's calculation of the Working Capital Reserve funding is consistent with PUC guidelines, which exclude fuel and other power supply costs from the calculation. However, Austin Energy recommends increasing the reserve to a minimum of 60 days of non-power supply costs in order to adequately account for Austin Energy's firm expense obligations associated with City transfers, including both shared services and the General Fund Transfer. These transfers are not considered when AE calculates the current 45-day target funding amount. Austin Energy recommends that there be a maximum limit on this reserve (*e.g.*, 90 days).

    b. Strategic Reserves – Austin Energy recommends eliminating this overarching collection of reserves because its structure is confusing and obfuscates the objectives and intentions of the underlying reserves. In its place, AE recommends one single fund to serve the "rainy day fund" function that was originally intended for the Strategic Reserves. AE recommends additional restructuring of the underlying reserves as described below:

        i. Emergency Reserve – The use and application of the Emergency Reserve is duplicative of and lacks clarity with respect to other reserves. Austin Energy, therefore, recommends the elimination of this reserve. If Council approves these policy changes, AE recommends that the dollars currently set aside in this fund should be moved to the Contingency Reserve and then to other funds, as described below.

        ii. Contingency Reserve – Austin Energy recommends that the Contingency Reserve be maintained and funded at a maximum of 60 DCOH, consistent with current financial policy. Primarily, Contingency Reserve funds should be used for unanticipated or unforeseen events that reduce revenue or increase obligations. In addition, Contingency Reserve funds should be used to replenish any other reserve fund when its level drops below the minimum threshold established in financial policy. Contingency Reserve funds should be replenished as soon as practically possible. AE recommends the Contingency Reserve be initially funded by transferring the outstanding balance of Emergency Reserve, assuming Council adopts the recommendation to eliminate that fund.

iii. Rate Stabilization Reserve – The Rate Stabilization Reserve should be moved out of the overarching Strategic Reserves collection and be renamed the Power Supply Stabilization Reserve to clarify its purpose. Currently, there are no funds set aside in this reserve.

c. Power Supply Stabilization Reserve – This fund should be dedicated to mitigating the impacts of volatile net power supply costs and, in essence, serve as a shield against significant changes in ERCOT wholesale market prices for AE's customers. Because the purpose of this reserve is to smooth customer bill impacts caused by variation in power supply costs, funding criteria for this reserve should be based on a range of days of net power supply costs.

i. Austin Energy recommends that the Power Supply Stabilization Reserve maintain a cash balance between 90 and 120 days of net power supply expenses.

ii. Austin Energy recommends that, if any funds remain in the Emergency Reserve after fully funding the Contingency Reserve, they should be moved to the Power Supply Stabilization Reserve. Further, Austin Energy recommends that the Power Supply Stabilization Reserve be funded in the future from net credit balances remaining in the PSA over or under account balance upon the annual PSA revaluing, rather than included as a credit in the calculation of the subsequent PSA. This recommended funding process ties the funding source to the use of funds (i.e., net power supply under-recoveries are funded from prior net power supply over-recoveries).[113]

d. Repair and Replacement Reserve – The Repair and Replacement Reserve is a critical source of funds that ensures AE has sufficient liquid resources to fund a portion of capital projects with equity as opposed to strictly using borrowed funds. This reserve gives AE an important tool in managing the utility's equity contribution to capital projects, per existing financial policies. In order to clarify that the purpose of these reserves is to fund the equity portion of all capital projects, Austin Energy recommends that this reserve be renamed the Capital Reserve.

i. Capital Reserve funds are available for use on all AE approved capital projects and can be used to manage the utility's debt to equity ratio in the long-term.

ii. Austin Energy recommends that the Capital Reserve be funded at a minimum of 50% of the prior year's depreciation expenses with no maximum limit. Without a maximum funding limit, Austin Energy

[113] Use of net credit balances to fund the Power Supply Stabilization Reserve does not imply elimination of the PSA's 10% over/under recovery calculation.

recommends accruing additional cash reserves as required so that the total of all reserve funds meets the 150 DCOH goal.

e. CIP Fund – No changes to the CIP Fund are recommended.

If the City Council were to adopt these recommended structural changes to AE's reserve fund policies and funding levels, AE would expect an additional decrease in the annual revenue requirement of approximately $8.2 million. This decrease assumes a three-year amortization period to reach full funding.

Revenue Requirement for Alternative Reserve Fund Proposal

Reserve Fund	**Unaudited FY 2015 ($)**	**Proposed Amount ($)**	**Difference** *(Over)/Under*
Working Capital	251,115,560	93,440,655	(157,674,905)
Strategic Reserves(1)			
Contingency	58,742,838	93,440,655	34,697,817
Emergency(1)	93,490,237	-	(93,490,237)
Rate Stabilization(2)	-	125,314,560	125,314,560
Repair & Replacement(3)	64,071	100,426,568	100,362,497
Mark to Market Adjustment(4)	(984,653)	-	984,653
Total	**402,428,053**	**412,622,438**	**10,194,385**
Total amortized over 3 years			**3,398,128**

(1) The Emergency Fund and its over-arching Strategic Reserves umbrella would be eliminated in this proposal.

(2) This fund would be renamed the Power Supply Stabilization Reserve and would move out of the Strategic Reserves umbrella.

(3) This fund would be renamed the Capital Reserve. Target funding amount of $72,825,880 plus an additional $27,600,688 to achieve at least 150 Days Cash on Hand.

(4) Because FY 2015 data is unaudited, an adjustment is made to reflect the true market value of the funds. Once the audit is complete, each fund will be adjusted accordingly.

As stated in subsection 1 above, AE recommends the IHE adopt AE's reserve fund revenue requirement based on current financial policy but offers these recommendations as policy changes for the IHE and City Council to consider.

As noted above, in their closing briefs, the ICA and NXP/Samsung suggest revisions to AE's proposed changes to reserve fund policies. These two parties use their own subjective judgement in place of AE's detailed analysis to revise certain parameters of the proposed reserve fund policies. As such, these revisions should be rejected.

The ICA supports AE's proposed change to the current Rate Stabilization Reserve.[114] By renaming the fund the Power Supply Stabilization Reserve and clearly stating its purpose as a tool to help mitigate unpredictable fluctuations in net power supply costs, the ICA believes the new reserve fund can help "insulate ratepayers from market volatility."[115] However, the ICA recommends funding for the Power Supply Stabilization Reserve be targeted at 90 days of net power supply costs.[116] The ICA's rationale for this revision is based on a flawed assumption that AE's proposed funding of the Power Supply Stabilization Reserve is based on a highly conservative, worst case estimate of needing 120 days of net power supply costs to protect customers from market volatility. In fact, AE's proposal recommends a funding level range of between 90 days and 120 days of net power supply costs. In order to calculate a revenue requirement adjustment based on the proposed alternative financial policies, AE picked 105 days of net power supply costs to represent a midpoint between the minimum and maximum funding levels. Under the proposed policy, if funding were to land within the 90 to 120 day range, AE would not seek to collect additional revenues for the Power Supply Stabilization Reserve. Similarly, if funding levels should be greater than 120 days, AE would move to rebalance the amount of reserves and ultimately adjust rates to reflect the over-collection.

"Given that the accumulation of reserves takes time and the risk mitigation benefit associated with the reserves is substantial,"[117] an initial revenue requirement based on the mid-point of the funding range is reasonable. Volatile market prices can quickly and significantly

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[114] ICA Brief at 29.

[115] ICA Ex. 1 at 23:17.

[116] ICA Brief at 31.

[117] AE Ex. 1 at 475.

impact AE's reserve balances. For example, one hour of wholesale prices at the market cap of $9,000/ MWh could result in a single day cost to AE of over $20 million, an amount that is payable to ERCOT within two business days. This single hour event represents approximately 15 days of net power supply costs. While the ICA is correct to point to affordability concerns with funding levels greater than 90 days of net power supply costs, the reverse scenario, in which AE must raise PSA rates in the middle of the year to cover volatile market costs, must be considered as well. AE recommends the 105 day initial funding level as a reasonable amount, recognizing that once the funding levels land within the 90 to 120 day range, additional funds will not be collected from ratepayers.

In addition, the ICA disagrees with AE's proposal to fund the Power Supply Stabilization Reserve by using net credit balance in the PSA. Instead, the ICA recommends the City Council maintain the current over/under collection calculation used in the PSA by which any over- or under-collections that are less than 10% of the total PSA value are factored into the PSA calculation for the coming fiscal year. The ICA appears to misunderstand the function of the net credit funding mechanism: it is not intended to continuously sweep funds from the PSA into the Power Supply Stabilization Reserve. Instead, if the Power Supply Stabilization Reserve is below its target funding levels and if the PSA has an over-recovery of less than 10%, then those excess revenues would be swept into the Power Supply Stabilization Reserve. This net credit funding mechanism would supplement, and ultimately reduce, any base rate revenue requirement adjustments needed for reserve funding. If either the PSA over-collection exceeds 10% or if the Power Supply Stabilization Reserve is within target funding levels, the over-collected PSA funds will be returned to customers following the normal procedures.

Using the net credit funding mechanism minimizes rate impacts on customers by potentially reducing the number of occasions when AE might need to adjust PSA or base rates.

In addition, the use of net credit funds in the Power Supply Stabilization Reserve maintains a causal link between source and use of funds. For these reasons, the net credit funding mechanism is reasonable and should be supported by the IHE.

In a similarly subjective manner, NXP/Samsung critiques AE about whether the utility can unilaterally substitute its proposed alternative financial policies in place of the existing policies.[118] NXP/Samsung confuses AE's argument that it cannot change its COS calculations for reserve funds for a stubborn resistance to considering competing ideas or policies. Nothing could be further from the truth. In fact, AE has not precluded any party from making recommendations about changes in reserve fund policy; rather, it has simply stated that the COS study will continue to reflect current financial policies, irrespective of any recommended changes, including those made by AE. If and when the City Council adopts different financial policies, then the COS model will be updated to reflect the funding impacts of those revised policies.

NXP/Samsung also disagrees with AE's proposed revision to the Working Capital Reserve. AE recommended increasing the Working Capital funding level from 45 to 60 days of non-power supply O&M costs in its alternative policy proposal. NXP/Samsung argues that the 45-day funding level mirrors PUC substantive rules and therefore, the 60-day proposal should be rejected.[119] However, NXP/Samsung's recommendation would negate the change sought by AE in favor of a standard that bears little application to AE's specific regulatory or business environment. The cited PUC rule does not apply to MOUs and does not consider the difference in operating environments for IOUs and MOUs. In fact, the primary reason for AE's recommended change to 60 days of non-power supply O&M costs is to reflect this fundamental difference.

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[118] NXP/Samsung Brief at 33.

[119] *Id.* at 34.

AE's obligation to transfer funds associated with shared service and with the City's General Fund Transfer should be appropriately considered as firm, ongoing, and substantive cash requirements that the utility must meet each month. IOUs do not have this type of regular fund transfer and consequently, the PUC's rules do not contemplate the impact these transfers might have on the utility's operating cash balances. It is reasonable for AE to increase the target funding amount for its Working Capital Reserve to 60 days in order to reflect more accurately its true monthly cash requirements. The IHE should reject NXP/Samsung's subjective argument.

Similarly, AE disagrees with NXP/Samsung's mischaracterization of the Power Supply Stabilization Reserve as "a distortion of Council's intent in setting the affordability goals."[120] NXP/Samsung offers no evidence or testimony to support this claim, only its conjecture that AE is seeking an easy way to collect money from its customers. There are myriad other ways that AE could more easily collect revenue from its customers than the Power Supply Stabilization Reserve. The IHE should recognize this argument for what it is: a subjective claim that can be rejected outright.

Finally, NXP/Samsung spends the remainder of their brief criticizing AE's proposed revisions to financial policies by focusing on the appropriateness of the use of the Cash Flow Method to determine AE's revenue requirement. Despite NXP/Samsung's efforts to cast AE as an IOU, Austin Energy is an MOU with financial policies that should be examined and reviewed through its specific MOU lens. Furthermore, the IHE should disregard or reject any discussion about its reserve fund policies based on a critique of the Cash Flow Method as this issue was identified as being beyond the scope of the case.[121]

AE's alternative reserve fund policy recommendations center around two primary objectives: (1) achieve and maintain 150 DCOH; and (2) divide those funds into discrete funds

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[120] *Id.*

[121] *See* Impartial Hearing Examiner's Memorandum No. 11 at 5 (Mar. 11, 2016).

whose purpose and use are transparent to the community. The alternative proposal attempts to eliminate some inherent redundancy and confusion built into the current policies and steers the use of funds towards strategies that will help keep the utility financially sound and help minimize future rate impacts on its customers. AE requests the IHE and City Council consider seriously these recommendations.

N. Property Transfers

1. Energy Control Center

Intervenor Paul Robbins initially raised the issue of the transfer of the former Energy Control Center ("ECC") located at 301 West Avenue.[122] In his Party Presentation and again during his testimony at the hearing, Mr. Robbins emphasized his desire to have the City have the ECC property re-appraised and then have the City's general fund reimburse Austin Energy for "the difference between the [$14.5 million] and the increased value today."[123] This suggestion is without legal support or precedent. Indeed, Mr. Canally testified that he is unaware of any situation in which the City has had property reappraised in this context.[124] For these reasons, Austin Energy requests that the IHE recommend that the Council not take the action proposed by Mr. Robbins.

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[122] Paul Robbins Motion to Intervene (Feb. 3, 2016) and Paul Robbins Party Presentation (May 3, 2016).

[123] Tr. at 512:4-14.

[124] Rebuttal Testimony of Greg Canally, AE Ex. 5 at 8:1-6.

While not initially addressed in their initial party presentations or testimony, in their closing briefs, NXP/Samsung,[125] the ICA,[126] and AELIC[127] raise issues related to the ECC transfer. All suggest that Austin Energy should have accounted for the monies it received from the City when setting the current proposed rates. Austin Energy disagrees with these proposals and requests that the IHE recommend that City Council not make any modifications to how Austin Energy utilized the proceeds from the ECC sale.

First and foremost, AE received the funds at issue during this current fiscal year,[128] not during the test year that Austin Energy used to set the proposed rates in this proceeding. NXP/Samsung and the ICA inexplicably claim that this fact is immaterial. Instead, NXP/Samsung posits that the utility should "reflect this amount as an offset to the Capital Improvement Plan transfer" and use the payment received as an offset to AE's overall revenue requirement.[129] In contrast, the ICA requests that the IHE direct AE to "quantify the cost of service impact of effectuating the city council's directive to use the proceeds to fund the costs of the new Energy Control Center."[130] Neither one of these actions is appropriate. This non-recurring source of funding, which was specifically used to pay down existing debt on a facility, should not be used to set rates.

AELIC makes an even more outlandish proposal for the use of the $14.5 million, concluding that the monies should be used to "adjust any reserve deficiencies AE may have."[131] This recommendation is at odds with the fact that the funds have been spent to reduce Austin

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[125] NXP/Samsung Brief at 37.

[126] AELIC Brief at 15-16.

[127] ICA Brief at 32-33.

[128] Tr. at 856:2-4.

[129] NXP/Samsung Brief at 37.

[130] ICA Brief at 33.

[131] AELIC Brief at 16.

Energy debt. Because the money has been used, it cannot be used again to adjust any reserve deficiencies.[132]

The transfer of the former ECC was done in accordance with City policy.[133] Austin Energy's receipt of funds from that transfer was in accordance with City policy.[134] The use of those funds to pay down existing debt incurred for the construction of the new ECC was done in accordance with City policy.[135] Therefore, AE requests that the IHE recommend to Council that no further action is necessary with respect to the ECC transfer.

2. Seaholm South Substation Land

Pursuant to Council resolutions, the Seaholm South Substation Land is being utilized to build the new Central Public Library.[136] The decisions related to the transfer were made in accordance with City policy.[137]

None of the closing briefs or testimony during the hearing address this property. Austin Energy requests that the IHE recommend to Council that no further action is necessary with respect to the transfer of the Seaholm South Substation Land.

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[132] Austin Energy's Response to AELIC RFI Nos. 10-5 and 10-6, AELIC Ex. 20.

[133] AE Ex. 5 at 7:9-24.

[134] *Id*. at 8:7-17.

[135] AELIC Ex. 20.

[136] AE Ex. 5 at 9:8-15.

[137] *Id*. at 9:16-18.

3. Vacant Lot at 2406 Ventura Drive

Austin Energy transferred this property to the Parks and Recreation Department ("Parks") on June 10, 2010.[138] The decisions related to the transfer were made in accordance with City policy.[139]

None of the closing briefs or testimony during the hearing address this property. Austin Energy requests that the IHE recommend to Council that no further action is necessary with respect to the transfer of the vacant lot at 2406 Ventura Drive.

4. Vacant Lot at 3400 Burleson Drive

Austin Energy transferred this property to Parks on June 10, 2010.[140] The decisions related to the transfer were made in accordance with City policy.[141]

None of the closing briefs or testimony during the hearing address this property. Austin Energy requests that the IHE recommend to Council that no further action is necessary with respect to the transfer of the vacant lot at 3400 Burleson Drive.

5. Holly Street Plant

The Holly Street Plant ceased operations in September 2007[142] and has been, since 1985, dedicated, per City ordinance, to revert to parkland.[143] Given these dates, the prior Austin Energy rate review was the appropriate time to consider and investigate all issues related to the costs associated with the plant.[144]

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[138] *Id*. at 10:2-5.

[139] *Id*. at 10:14-17.

[140] *Id*. at 10:19-21.

[141] *Id*. at 11:10-13.

[142] *Id*. at 6:12-14.

[143] *Id*. at 19:6-13.

[144] *Id*. at 6:12-14.

Mr. Robbins states that he was not afforded an opportunity to address this issue in the prior rate review because a process like the one currently being utilized did not exist.[145] While it is true that this in-depth, formal process had not been established for the 2009 rate review, there were still numerous discussions in a variety of public forums and the City Council members were, of course, available for meetings and accessible via email, letter, and telephone. Moreover, the same information about the transfers provided to Mr. Robbins throughout the course of this proceeding would have been available to him during the prior review through the PIA.

The fact that the process developed for the current rate review is different than the one used previously does not justify the examination of properties that would have been an appropriate subject of debate in the previous review.

Ultimately, however, none of the closing briefs or testimony during the hearing address this property. Austin Energy requests that the IHE recommend to Council that no further action is necessary with respect to the transfer of the Holly Street Plant.

III. COST ALLOCATION

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

Austin Energy recommends that costs associated with the 311 Call Center should be assigned to the customer function. In addition, A&G salaries should be functionalized to each function based on labor.

In contrast to AE's proposals, ICA Witness Johnson recommends that the 311 Call Center Expense be functionalized to the distribution function instead of the customer function. He further recommends that A&G salaries be functionalized using a Non-Fuel O&M allocation

[145] Tr. at 499:25-500:3.

factor. For the reasons discussed in Mr. Mancinelli's rebuttal testimony and below, Mr. Johnson's recommendations should be rejected.

1. Functionalization of the 311 Call Center

The 311 Call Center is a communication system that connects users with various city departments, including Austin Energy. The cost of the call center is driven by call volume, which best correlates with the number of customers. As a result, the 311 Call Center should be functionalized to customers and allocated to each rate class based on the number of customers in the class. The 311 Call Center provides a community benefit that should be distributed equally between customers.

Mr. Johnson's recommendation to assign these costs to the distribution function reflects his misinterpretation of the use and benefit of the 311 system. Specifically, his proposal to functionalize the 311 Call Center to distribution and allocate these costs to rate classes using distribution O&M expense would result in customers with larger demands paying a greater share of 311 Call Center costs compared to customers with smaller demands. This end result is inappropriate because the benefit associated with access and use of the 311 Call Center is the same for customers of all sizes.

Mr. Johnson contends that the disaster recovery portion of the 311 Call Center cost is presumably focused on restoring power service, but this cost actually has nothing to do with grid operations. Emergency use of the Call Center is no different from normal use of AE's customer service center. In both cases, customers are able to call and report service interruptions, billing issues, or other concerns to AE and other City departments. The disaster recovery benefits of the 311 Call Center are associated with a remote site that can be used on a moment's notice to avoid disruption of availability. The 311 Call Center provides AE communications redundancy with the same underlying use and benefit as the customer service center. For these reasons, AE's COS treatment of the 311 Call Center is reasonable and should be adopted.

2. FERC 920 Administration and General Labor Costs

A&G labor costs are properly allocated through the use of a labor allocator. A labor allocator recognizes that the primary administrative function of the utility is the management of the labor force. Use of a non-fuel O&M allocator, as proposed by Mr. Johnson, distorts this COS relationship and unduly shifts costs to the generation function. O&M includes a large amount of non-labor expense items that can vary by year and function. A large portion of these expenses are related to infrastructure maintenance requirements. These expenses do not align well with the level of effort of the management team or the underlying staff. This is particularly true for the production function, which is subject to periodic expensive unit overhauls. Compared to other functions, non-labor maintenance cost is very high for production. This is shown in the following table which compares test year labor cost as a percentage of total costs by function. Please note that the production function O&M calculation shown below excludes FPP and the STP.

Function	AE Labor Costs[1]	AE Non-Fuel O&M (Excluding Transmission by Others, FPP & STP)[2]	Percent of O&M that is Labor Related
Production	$23,018,932	$146,927,138	15.7%
Transmission	$10,112,235	$13,872,035	72.9%
Distribution	$39,788,187	$60,207,313	66.1%
Customer	$37,972,802	$60,540,745	62.7%

Labor Data from RFP WP D-3
Non-Fuel O&M from RFP WP F-1.9 with adjustments from Schedule G-2 & Schedule G-3

Labor cost as a percent of total O&M is significantly lower for the production function compared to the other functions because non-labor expenses are much higher for the generating units compared to transmission and distribution infrastructure. As a result, O&M less fuel is a poor allocator of A&G costs because this method unjustly shifts a significant amount of management labor costs to the production function.

With respect to his arguments pertaining to STP and FPP, Mr. Johnson misrepresents AE's allocation of FERC Account 920 - A&G labor expenses. AE correctly allocates these costs using labor, then directly assigns an additional $3.3 million in A&G labor costs to the production function for STP and FPP administration costs. AE accounts for these costs separately, therefore, they can be directly assigned. In total, when accounting for the direct assignment, AE allocates approximately 28% of total FERC 920 costs to the production function. This is 7% higher than what would be otherwise allocated using a labor allocator without a direct assignment. AE recognizes the cost of A&G labor associated with FPP and STP and properly handles this in the allocation method.

Finally, Mr. Johnson acknowledges that his proposed allocation method significantly shifts the allocation of A&G costs to the production function. He claims that this result is justifiable because all customers on the system use the production function compared to transmission and distribution functions. For example, customers receiving electricity service at higher voltages only pay for a portion of the transmission and distribution systems. Witness Johnson seems to imply that these high delivery voltage customers are not paying their fair share of A&G costs compared to customers with secondary delivery voltages. This is not true. A&G expense is a necessary indirect cost associated with all utility functions. These costs are properly allocated to each function based on labor costs. In the RFP, within each function, these costs were further assigned to each sub-function using a combination of direct assignments and labor allocators. The end result of this allocation process is that the various components of the AE production, transmission, distribution, and customer service functions include a reasonable amount of indirect costs, including FERC Account 920 A&G labor. Customer use of these various system components dictate the appropriate COS responsibility associated with these indirect costs. High service voltage customers should only be required to pay their fair share of indirect costs associated with high voltage infrastructure. The ICA's proposal would disproportionally shift indirect costs to the production function and away from the transmission and distribution functions. As a result, large electric users will pay too much of these overhead costs while small users will pay too little. For these reasons, Mr. Johnson's A&G COS proposal should be rejected.

3. New Service Connection Fees

Mr. Johnson recommends that New Service Connection Fees be assigned to the customer function rather than the distribution function. These services directly relate to the distribution system infrastructure required to connect the customer. They are collected for initiating new services and reconnecting after failure to pay.[146] Therefore, these costs are properly functionalized to the distribution system.

B. Classification of Production Costs

Austin Energy classifies fuel and recoverable purchased power as energy related expenses. This classification is consistent with the short-run view and represents a large percentage of AE's short-run variable costs. Use of the short-run view closely reflects actual variable costs incurred by AE when units are dispatched into the ERCOT market. When AE bids generation into the market, the bid accounts for short-run variable costs such as fuel cost (including delivery), variable O&M ("VOM"), and unit start-up and shut-down costs. Mr. Johnson acknowledges this fact in his testimony, which states:

> Under ordinary conditions, generators will submit bids close to the generation unit's variable cost in order to ensure that the unit

[146] AE Ex. 3 at 62 (Exhibit JAM-2).

> operates when it is economic to do so. As a result, the generating units' annual hours of operation will depend on its variable costs.[147]

Despite this acknowledgement, Mr. Johnson recommends classification of production O&M costs using the NARUC Cost Allocation Manual ("CAM") approach. Given AE's current business environment, this approach is inappropriate.

The description of fixed and variable production costs in the CAM were developed when the electric utility industry was comprised of vertically integrated utilities operating in a monopoly business environment. These guidelines were developed long before the deregulation of wholesale power markets. Today's business environment in the ERCOT market is very different from the monopoly environment of vertically integrated utilities that existed when NARUC's CAM Cost Accounting classification guidelines were published. Significant changes in the ERCOT power market have impacted the industry's business operations. Like other Texas utilities, AE is faced with a competitive wholesale power market, aggressive conservation and demand response goals, increased interest in distributed generation options by customers, and long-term, low-load growth projections. All of these factors create load uncertainty, energy volatility, and greater revenue instability. Fixed cost recovery is no longer certain in the wholesale power market or through rates. The CAM's consideration of long-run variable costs are not applicable to generation facilities in a nodal market and are more appropriately considered a demand-related cost. Therefore, the CAM classification guidelines pertaining to production infrastructure that the ICA has relied upon are not relevant and should not be considered by the IHE.

AE's classification of production variable costs aligns with the economics of generation dispatch in ERCOT and reflects costs AE will recover from the market. Depending upon market prices, other costs above and beyond these short-run variable costs may be recovered, but this is

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[147] ICA Ex. 1 at 45:8-11.

not guaranteed. As a result, AE customers are ultimately responsible for some or all of the generation costs above short-run variable costs. Given that it is proper to recognize short-run variable costs as energy related, it is also proper to recognize O&M expenses as demand related. AE generation assets must be in a state of "readiness to serve," or operationally available, when market conditions provide economic opportunities for dispatch. O&M practices are critical in keeping units available to operate on short notice. In the current business environment, AE measures Commercial Unit Availability ("CUA"). CUA is a critical performance indicator that measures the availability of a unit to operate when the unit is "in the money," or struck in the market. With high CUA, AE generation resources can effectively act as a financial hedge and protect customers from costly market events. O&M expenses (excluding fuel and VOM) ensure high CUA and capacity-on-demand for all AE generation resources. Therefore, these O&M expenses are properly classified as demand related costs in the nodal market. For these reasons, Mr. Johnson's production function classification recommendations should be rejected.

C. Allocation of Production Costs

Data Foundry and the Austin Chamber of Commerce ("DF/ACC") argue that Austin Energy's production costs should be allocated based on the Average & Excess ("A&E") 4CP allocation methodology.[148] NXP/Samsung makes a similar claim. DF/ACC and NXP/Samsung, in part, base their recommendations on the traditional recognition and approval of 4CP-based allocation methodologies at the PUC. However, AE agrees with the ICA that historical precedence should play a diminished role in this retail rate examination due to the deregulation of the ERCOT region and the evolving structure of its energy-only market.

Additionally, DF/ACC and NXP/Samsung rely on an erroneous understanding of fundamental ERCOT wholesale market principles to advocate for a 4CP-based allocation

[148] Data Foundry/Austin Chamber Cost Allocation and Revenue Distribution Brief at 6-8 ("DF/ACC Brief").

methodology. In truth, the principle reason for DF/ACC's recommendation is plainly stated as a way to redistribute $10 million of production cost back to the Residential class.[149]

ICA Witness Clarence Johnson recommends AE use a BIP allocation methodology. PC/SC calls for a similar allocation methodology. However, the BIP method, and other methods that overweight the importance of hourly energy needs, is as flawed as the 4CP-based methods in its failure to recognize fundamental market principles. Instead, AE's recommended 12CP allocation methodology more accurately reflects how the ERCOT nodal market impacts production costs and is a reasonable way to assign the recovery of those costs to AE's customer-owners.

Historical Precedence

Since deregulation occurred in 1999, the PUC has conducted little retail rate review of utilities operating in the ERCOT market. Nearly all of the PUC's retail rate examination has focused on the fully-regulated, vertically-integrated utilities operating outside the ERCOT region.[150] To look to vertically-integrated utilities for appropriate cost causation methodologies, as DF/ACC advocates in their brief,[151] is to ignore the significant differences between the ERCOT wholesale market and the fully regulated environment in which these vertically-integrated utilities operate. Unlike Austin Energy, vertically-integrated utilities are not subject to wholesale market forces in which generation companies must compete based on economic efficiency in order to have their units run. And, unlike vertically-integrated utilities, AE's generation resources are not exclusively maintained to meet system peak; rather, they are maintained to be dispatched based on system wholesale price. Consequently, relegating the

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149 *Id*. at 5.

150 The sole case was the appeal of Austin Energy's retail rates for outside city limits customers by Homeowners United for Rate Fairness in 2012-2013. While the PUC approved an A&E 4CP allocation methodology at that time, one case does not substantively establish "historical precedence."

151 DF/ACC Brief at 7.

production cost allocation methodology to a market paradigm that is no longer relevant for AE disconnects the cause of production costs from the allocation of those costs to the appropriate rate classes.[152] Consideration of different methodologies is warranted in order to avoid an overreliance on a traditional approach that is outdated, and it is appropriate for AE to consider other factors in addition to historical precedence when determining the most reasonable production cost allocation methodology.

Austin Energy did, however, keep historical precedence in mind when adopting a coincident peak-based methodology to allocate production costs. The shift from A&E 4CP to 12CP maintains the relationship between those demand-related costs and the classes which contribute to demand during those periods of the year. The 12CP method simply acknowledges that price spikes caused by demand for energy can occur throughout the year in the ERCOT market. As demonstrated by AE Witness Mancinelli, the 12CP allocator recognizes the top 20% of hours in the year and thus, can capture the costs borne by AE to keep its resource fleet available for dispatch when prices warrant dispatch.[153] When market price spikes can occur as often in February as they do in August, critique of the historical precedence of a summer peaking methodology is reasonable.

With regard to historical precedence of the BIP method, NXP/Samsung Witness Gary Goble erroneously testified during his cross-examination by the ICA that PUC staff recommended rejecting the BIP method in the appeal of AE's retail rates for outside city customers in PUC Docket No. 40627.[154] This is factually incorrect as AE did not present a cost

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[152] *See* Tr. at 783:10-784:8. *See also*, ICA Brief at 48, 56.

[153] AE Ex. 3 at 41:20.

[154] Tr. at 463:12-20.

of service model using BIP during its rate review. Rather, AE presented to the PUC the A&E 4CP in its cost of service model.[155]

ERCOT Wholesale Market

DF/ACC's argument in favor of the A&E 4CP methodology demonstrates a lack of understanding of how ERCOT nodal market prices impact the production costs of resources needed to meet demand. The ERCOT nodal market is based on the supply of and demand for energy in five minute intervals, and when demand for energy outstrips the available supply, prices rise to encourage resource owners to make more energy available to the market.[156] These price increases can occur at any time in the year, not only when peak demand is reached. Similarly, generation resources are dispatched based on the marginal price offered by the resource owner, not when demand on the system reaches its peak.

Yet, DF/ACC cites passages from the American Public Power Association's ("APPA") 1979 manual *Cost of Service Procedures for Public Power Systems* which describe the importance of peak demand in determining the proper allocation of production costs.[157] It is notable that this manual was developed during an era that could not contemplate a deregulated, energy-only, wholesale electricity market. DF/ACC's argument fails to recognize that wholesale market price increases do not exclusively occur during peak demand periods of the year. Moreover, DF/ACC broadly and erroneously over-emphasizes the importance peak demand plays in AE's production cost analysis,[158] whereas they should be most concerned with peak price intervals.

[155] AE Ex. 3 at 38:13-14.

[156] *See* AE Ex. 1 at 042-044.

[157] DF/ACC Brief at 6.

[158] *Id*. at 7.

While it is true that average wholesale prices tend to be higher during the summer months when demand typically reaches its peak, AE has shown that high market prices are not exclusive to the four summer months.[159] They can and do occur throughout the year, and spikes can be significantly higher than average prices, even higher than the average summer month prices. Wholesale prices can rapidly escalate from an average range between $20 and $40/ MWh to as high as $9,000/ MWh. Given the wholesale market's fundamental design, MOUs with both generation resource fleets and load-serving obligations must be concerned about the marginal price of electricity in any given 15-minute interval, not the overall average price over the course of month or season. These price spikes represent unacceptable risks against which the MOU must hedge its exposure: in AE's case, it uses its resource fleet to hedge in part against the volatility of the energy-only market.

In order to ensure that its resources are available to provide energy when market prices escalate, AE must maintain its fleet throughout the year. Mr. Mancinelli stated that O&M expenses help maintain the operational readiness and commercial availability of the fleet and are appropriately classified as demand-related costs.[160] It is therefore reasonable for AE to allocate its production costs based on a methodology that considers the impact of market price spikes throughout the year.

Whereas DF/ACC appears to have a fundamental misunderstanding of how the ERCOT wholesale market functions, ICA Witness Johnson adheres to an outdated production stack dispatch model to describe how AE incurs production costs. In reality, ERCOT's Security Constrained Economic Dispatch engine uses an economics-based stack to determine which unit runs next. This fundamental market construct explicitly influences when AE incurs production-related costs.

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[159] AE Ex. 1 at 165.

[160] AE Ex. 3 at 27:13-17.

In the ERCOT nodal market, there are no longer "base hours," "intermediate hours," or "peak hours." Instead, the variation is centered on price: "low priced intervals," "medium priced intervals" and so on. As Mr. Mancinelli wrote, "Given low price market conditions, AE generation resources may sit idle for long periods of time. Conversely, during high price market conditions, all AE generation resources may be dispatched."[161] Because ERCOT dispatch is dictated by market prices, at any given interval during the year, dispatched units may no longer fall neatly within the traditional BIP nomenclature; dispatch goes simply to the next lowest marginal cost unit required to meet system demand. As described above, AE incurs costs to maintain resource fleet "readiness" in the event that prices increase. These high priced intervals can occur during the traditional "base hours" or "peak hours." Thus, reducing O&M costs to three outdated tranches of BIP hours neglects implicit cost causation principles associated with the fact that ERCOT's "peaking" units may run equally during peak pricing events in February and August.

Moreover, the hourly dispatch construct is a moot notion in the ERCOT nodal market. Prices can escalate from $20/ MWh in one 15-minute interval to $500/ MWh (or more) in the next 15-minute interval, and then back to $20/ MWh in the next. In this example, so-called "peaking units" are not necessarily dispatched in the high price interval; it is the next unit with the lowest marginal cost that is called on to run. In this specific case, it may be that a "baseload" unit has available capacity to offer that is cheaper to dispatch than a "peaking" unit, contrary to Mr. Johnson's depiction of the market. The notion that there is a base hour or a peak hour in this scenario belies the principles underlying wholesale market design.

Fundamentally, Mr. Johnson's advocacy for the BIP production cost allocation methodology is rooted in an outdated view of the ERCOT market. Similarly, his analysis and

161 AE Ex. 3 at 33:31-34.

calculations are constructed to attempt to match specific AE loads with specific AE generating resources.[162] In essence, Mr. Johnson's proposed allocation methodology would shift the preponderance of the costs of the most capital-intensive resources to larger commercial classes and away from the Residential class. But, AE has shown that, since the advent of the nodal market, this is not an appropriate way to distribute production related costs because AE no longer serves its own load with its resources. Instead, an allocation methodology that recognizes a reasonable number of wholesale market intervals during which AE readies its fleet for dispatch is a sound way to attribute production costs.

As NXP/Samsung Witness Gary Goble wrote in his cross-rebuttal testimony:

> The cost to AE of meeting its power supply requirements through generation plant construction by AE was decoupled with the operation of the ERCOT nodal market. This separation of identifying peak demand capacity needs and selection of the type of generation plant to build renders obsolete the production allocation methods such as the BIP and the Probability of Dispatch, which match loads and plant types.[163]

Although AE agrees with Mr. Goble in this regard, his critique of AE's proposed 12CP allocator relies on some unconventional thinking and should be discredited by the IHE. First, Mr. Goble confuses the association of costs and benefits in AE's hedging year-round wholesale market volatility.[164] He claims that AE has attributed production costs based on the benefits accrued to customers; this is patently untrue. AE's production cost allocation method assigns cost based on a class' coincidence to ERCOT peak demand each month. AE made this assignment because the utility incurs costs to keep its fleet ready to respond market pricing events every month. By suggesting allocation of costs based on the year-round benefits of AE's

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[162] AE does not offer specific rebuttal to Mr. Johnson's BIP-N or BIP-R methodologies given AE's outright rejection of a BIP-based allocator.

[163] Cross Rebuttal Testimony of Gary Goble, NXP/Samsung Ex. 4 at 7:10-15.

[164] NXP/Samsung Brief at 43.

physical hedging activity and then drawing a link to other assets owned by AE, he misses the simple cost causation principle that cost drivers determine how to allocate expenses, not the benefits. No reasonable party would claim that the costs of metering are attributable on a year-round basis; instead, the costs are appropriately associated with a customer. Similarly, the costs of owning transmission assets are associated with avoiding system reliability issues when peak demand is at its highest. Therefore, the costs are appropriately allocated on a 4CP basis. This confused logic serves only to cloud the issue that AE's generation resource fleet serves as a hedge against volatile market prices which can occur anytime throughout the year, as AE has amply demonstrated.

Mr. Goble's second argument is that AE has confused the cause and effect of owning and operating a generation resource fleet.[165] AE never indicated that it acquired resources before the introduction of the deregulated market to serve as financial or physical hedges. In fact, AE originally acquired those resources to serve its native load in an era and market construct that no longer exists. The fact that the laws, regulations, and market design have all changed since AE acquired its resources is immaterial to the fact that, today, AE uses these resources to mitigate volatile market price impacts for its customers. There can be no confusion that this is an appropriate use of resources for an MOU that has a generation fleet and an obligation to serve load.

Mr. Goble's third argument claims that AE should establish a class revenue requirement based on the cost of providing service and not the benefits of the service. He states, "[c]osts should be allocated based upon factors that drive the costs…."[166] AE has consistently argued that the production cost drivers are associated with maintaining fleet readiness year-round so that

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165 NXP/Samsung Brief at 43-44.

166 *Id*. at 44.

its units can run when economics merit dispatch.[167] In fact, AE's recommended ERCOT 12CP is the production cost allocation methodology that most closely links the costs of maintaining fleet readiness to the customer classes that drive the cost.

Finally, Mr. Goble argues that the 12CP methodology fails to properly recognize seasonal peak demand.[168] In the extreme, Mr. Goble's argument may be correct: a production cost allocation methodology which uses 8,760 peak inputs, such as the one proposed by PC/SC,[169] would obliterate the notion that demand is an important factor in determining cost causation. However, AE has not advocated the use of such a mechanism: it has recommended an allocator using 12 peaks.

The concept of the ERCOT 12CP is rooted in the fact that peak pricing drives production costs, and seasonal peak demand is less relevant in today's nodal market. To AE, the cost of readying its fleet to respond to a two-hour interval in April when market prices are $2,000/ MWh are the same as readying the fleet to respond to a two-hour interval in August when market prices are $2,000/ MWh. Demand is important, but seasonality is less important in the cost causation of production-related costs. It is vital that AE's production related costs be based in the reality of how AE operates in the ERCOT market for it to accurately assess costs to the appropriate customer classes.

However, PC/SC's contention that hourly energy data is the most appropriate input for production cost allocation study is not based on an analysis of AE's operations or business environment. It is based on a cursory review of hundreds of pages of materials by an individual who was not a party to the proceedings. In fact, Mr. Jim Lazar, the individual on whose

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[167] *See* for example, AE Ex. 1 at 047, 108, 114, and 117; AE Ex. 3 at 32-42; Rebuttal Testimony of Mark Dreyfus, AE Ex. 9 at 42-48; Tr. at 176:24-178:18.

[168] NXP/Samsung Brief at 44.

[169] PC/SC Brief at 15.

commentary PC/SC based its production cost allocation recommendations, wrote in the very first paragraph of his letter to the City of Austin's Electric Utility Commission ("EUC"), "[t]he following observations are the result of a few hours examining the cost of service and rate design reports to the EUC and the [Austin] City Council. They should not be considered an exhaustive review, and there may be errors in my interpretation of the methodology that AE has employed…."[170] Mr. Lazar himself notes that his analysis is incomplete; AE recommends the IHE consider it incomplete as well.

Similarly, PC/SC Witness Paul Chernick admitted to conducting an incomplete analysis of AE's production costs in a passage that directly follows the cross-examination testimony cited in PC/SC's closing brief.[171]

> Q. Mr. Chernick, I'm just asking simply, has
> PC-SC recommended that these methods just be analyzed
> for purposes of this proceeding?
>
> A. Well, I'd have to review the text in
> some -- with a great deal of care to try and parse that
> out.[172]

Just as he does in the question and answer cited above, Mr. Chernick admits again later in his cross-examination that he did not participate in the drafting of his testimony or produce any quantitative analysis on behalf of PC/SC.[173] Mr. Chernick's claims cited in PC/SC's Brief should be viewed as an incomplete analysis which did not consider AE's specific operations or business environment, and should be rejected outright.

Throughout the rate review, parties have disagreed over which production cost allocation methodology most appropriately reflects ERCOT market fundamentals and cost causation

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[170] AE Response to PC/SC RFI No. 2-7, PC/SC Ex. 31 at 14.

[171] PC/SC Brief at 16.

[172] Tr. at 701:23-702:3.

[173] Tr. at 712:6-12.

principles. For example, AE agrees with Mr. Johnson that AED 4CP "should be rejected as overly simplistic and inconsistent with ERCOT dispatch principles."[174] But, AE agrees with Mr. Goble that "[f]oremost among the numerous problems that render the BIP-R unreasonable and inappropriate for use is the false notion of how system planning occurs in the ERCOT power supply market in which Austin Energy operates."[175] Accounting for both these concerns, AE's recommended ERCOT 12CP production cost allocation methodology comes closest to mirroring ERCOT wholesale market fundamentals and reasonably balances cost assignment among the various rate classes based on documented cost causation principles.

D. Classification and Allocation of Distribution Costs[176]

1. Classification of Distribution Costs

Distribution transformers and capacitors perform demand related functions and therefore, their costs should be classified as demand related. In addition, meter expenses are customer related and should be classified on a customer basis. Finally, the costs associated with service connections vary based on customer demand requirements; therefore it is appropriate to classify services as demand related.

In contrast, ICA Witness Johnson recommends classifying transformers and capacitors as energy related. He also recommends that meter expenses be classified as both customer and demand related instead of solely customer related. Also, Mr. Johnson recommends the classification of services as customer related, instead of demand related. As discussed in Mr. Mancinelli's rebuttal testimony, AE's classification approach associated with these expense items is appropriate and correct.

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[174] ICA Brief at 58.

[175] NXP Brief at 40.

[176] The briefing outline did not include a heading for issues related to the classification of distribution costs. Accordingly, AE has combined classification and allocation related distribution issues into this section of the brief.

(a) Transformers and Capacitors

To ensure reliability of service to customers, distribution transformers are sized to meet customer maximum demands on the system. These transformer costs are fixed, meaning that they do not vary with energy use. It is standard industry practice to classify transformers as demand related costs and allocate these costs on some measure of customer demand. In the RFP, AE allocates these costs using the Sum of Maximum Demands ("SMD") method. SMD reflects the maximum monthly demand a customer places on the system during each month of the year. This classification approach has been widely accepted by the PUC in prior rate proceedings.[177] Also, Transmission and Distribution Utility ("TDU") rate structures approved by the PUC, and applied to customer classes with demand meters, recover distribution costs entirely from customer and demand charges. This fact illustrates that transmission and distribution costs are not related to energy.

Notwithstanding these facts, Mr. Johnson proposes to classify a portion of transformers and capacitors as energy related. While it is true that energy is lost during the transformation process, the underlying cost driver of this investment is demand. Using Mr. Johnson's logic, a customer using little to no energy would pay nothing associated with the installed transformers dedicated to serve that customer's load. Yet, when this customer needs electricity, the transformer investment is standing by to meet that demand requirement. Clearly, the transformer provides a significant benefit to the customer and that benefit is best measured with demand.

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[177] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695 (Feb. 23, 2016); *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 41791 (May 16, 2014); *Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment*, Docket No. 39896 (Nov. 2, 2012); *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 37744 (Dec. 13, 2010); *Application of CenterPoint Energy Houston Electric, L.L.C. for Authority to Change Rates*, Docket No. 38339 (June 23, 2011); *Application of Sharyland Utilities, L.P. to Establish Retail Delivery Rates, Approve Tariff for Retail Delivery Service, and Adjust Wholesale Transmission Rate*, Docket No. 41474 (Jan. 23 2014).

Mr. Johnson's logic is also inconsistent with the development of standby rates that backup customers who self-generate their own electricity. Among other things, standby rates recover the cost of distribution infrastructure, like transformers, through a monthly fixed charge. The monthly fixed charge recognizes that this utility investment is valuable to the customer in the form of grid access and reliability, regardless of the amount of energy used. For similar reasons, capacitors are classified as demand related expenses. Capacitors are required on the system for voltage support and represent fixed costs to the utility. For these reasons, Witness Johnson's recommendation to classify transformer and capacitor costs as energy related should be rejected.

(b) Meters

The costs of meters are a function of the number of customers and are, therefore, correctly classified by AE as customer related costs. A customer related classification is supported by the NARUC CAM and the PUC routinely uses this classification in TDU rate cases.[178] Additional costs of metering equipment for larger customers have already been accounted for in the COS by the application of a customer count allocation of meter costs using a weighted meter cost.

Classifying a portion of meter costs as demand related, as Mr. Johnson suggests, would result in shifting metering costs from customers with small demand requirements to customers with large demand requirements. This would result in cross subsidization of metering costs where small demand customers, like residential customers, would pay too little for metering expense and large commercial customers would pay too much.

Johnson supports his demand allocation argument by alluding to demand response and load shifting benefits potentially derived with advanced metering infrastructure ("AMI") meters

[178] *Id.*

and new rate designs. Currently, any benefits associated with these types of customer responses are small on the system. According to AE's Response to ICA RFI No. 1-20, all commercial and industrial meters and 10% of residential meters are currently capable of providing interval data.[179] Currently, only 10% of all commercial and industrial customers and 10% of all residential customers are currently sending interval data back to the utility. If benefits do exist, they are related to the avoided cost of future investments on the production, transmission, and distribution systems. These potential future benefits are not related to the metering investment, which remains an investment made on a per customer basis. For these reasons, Mr. Johnson's recommendation to classify a portion of metering costs to demand should be rejected.

(c) Services

Services can be classified as customer related expenses. However, when this classification approach is pursued, the underlying customer allocator is weighted between classes. This weighting recognizes that service costs vary between customers based on the customers' demand requirements. For example, in 2011, Oncor Electric Delivery Company, LLC, in Docket No. 38929, used a weighting of approximately 1 for residential, 10 for secondary >10kW, and 100 for large primary/transmission.[180] Further, in regard to services, the NARUC CAM states:

> This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

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[179] AE Ex. 3 at 63 (Exhibit JAM-3).

[180] *Application of Oncor Electric Delivery Company LLC for Authority to Change Rates*, Docket No. 38929 (Aug. 26, 2011).

Given that any weighting of services is based on class demand requirements, AE's classification of services as demand related and the allocation of the cost to each class based on SMD is a reasonable and fair treatment of these costs.

Even if one assumes services are a customer related expense, rate class weighting factors would be similar to SMD allocators previously discussed. As a result, the impact of this classification change on COS results would be minor. Also, such a classification would make service costs eligible to be included in the customer charge of each rate class rather than a component of demand. Again, however, this change in treatment would have little impact on rate design. This is particularly true for the residential class, where the proposed residential customer charge is less than half of what could be reasonably charged based on the COS analysis. For these reasons, Witness Johnson's recommendation to classify services as customer related should be rejected.

2. Allocation of Distribution Costs

Distribution substations, poles, and conductors should be allocated using the 12 Non Coincident Peak ("NCP") allocator. In contrast, NXP/Samsung Witness Goble recommends using the 4NCP method for allocating distribution substations, poles, and conductors.

As noted in Mr. Mancinelli's rebuttal testimony, the use of 12NCP is more equitable than 4NCP.[181] This is because the 12NCP method recognizes that distribution capacity provides value to customers throughout the year, not just during the peak hour or the summer peak months. Because the NCP calculation is done at the class level, off peak or seasonal customers may not be fully accounted for in a 4NCP calculation. A 12NCP calculation solves this problem. This is important as customers are becoming increasingly interested in distributed generation options and are able to shift load. From a cost allocation perspective, certain rate classes may be able to

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[181] AE Ex. 3 at 43.

avoid a portion of distribution demand related costs by shifting demand during NCP periods. If the demand measure is just a few hours (i.e., the 4NCP), the ability to shift and avoid cost responsibility is easier compared to a 12NCP method. Additionally, the distribution system is spread across the geographic footprint of the system. The system is sized in consideration of localized demand that varies from area to area based on variations in the customer mix. These variations are better represented by a 12NCP allocator which takes into consideration the value of load diversity across the distribution system.

E. Allocation of Customer Service Costs

1. Uncollectible Expense Allocation

Austin Energy has directly assigned uncollectable accounts. Directly assigning the cost of uncollectible accounts to each rate class is a highly supportable and equitable method for recovering these costs from customer classes. The NARUC CAM, regarding uncollectible account expense, states:

> Customer-related costs (Accounts 901-917) include the cost of billing and collection, providing service information, and advertising and promotion of utility services. By their nature, it is difficult to determine the "cause" of these costs by any particular function of the utility's operation or by particular classes of their customers. An exception would be Account 904, Uncollectible Accounts. Many utilities monitor the uncollectible account levels by tariff schedule. Therefore, it may be appropriate to directly assign uncollectable accounts expense to specific customer classes.[182]

NARUC acknowledges that directly assigning these costs to each rate class is appropriate.

In contrast to direct assignment, the ICA proposes to allocate uncollectable accounts to each rate class based on the class revenue requirement. Mr. Johnson suggests that the direct assignment approach could result in volatile results by class. To test his concern, AE Witness

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[182] Electric Utility Cost Allocation Manual, January 1992 at 102.

Mancinelli compared the direct assignments associated with uncollectible accounts included in the prior rate case with that of the current RFP. Because commercial account designations have changed between studies, Mr. Mancinelli compared the allocation of uncollectible accounts to the residential class compared to other rate classes. His analysis is summarized in the following table:

Uncollectible Direct Allocator

Rate Case	Residential	All Other Classes
2009 - Previous Rate Case	90%	10%
2014 - Current Rate Case	91%	9%

The direct assignment comparisons show that the direct assignment method yields a stable result. This result is not surprising given the number of bills rendered and the underlying socioeconomic conditions of various rate classes.

2. Meter Expense and Meter Reading

Meter expense should be allocated using a weighted customer allocator. Meter reading costs should be allocated based upon the number of customers. ICA Witness Johnson proposes that meter expense be allocated using a combination of customer and demand allocators. He further recommends that meter reading costs be allocated using weighted meter investments. Both of Mr. Johnson’s recommendations should be rejected.

Meter expense is a customer related expense. AE has properly accounted for cost differentials between meters through the use of weighting factors used in the customer allocator. Any use of demand in the allocation of meter expense is unsupportable from a cost causation perspective, and unduly shifts metering expense from small to large demand customers.

Meter reading costs should be allocated to each class based on the number of metered customers. This is because AMI meters, including the supporting meter data management and billing systems, represent technologies that readily gather data and render bills. Mr. Johnson proposes to allocate meter reading expenses on a weighted customer allocator. However, metering configurations and rate complexity have no impact on the level of effort to read a meter. As such, it is appropriate to allocate the meter reading costs to each class based on the number of metered customers.

3. Customer Service Accounts

(a) Marketing and Advertising

The proper manner to allocate marketing and advertising costs in FERC Accounts 908-910 is based upon the number of customers. Instead of using this allocation method, ICA Witness Johnson recommends allocating these costs based on weighted allocators representing 50% class revenue requirement and 50% number of customers.

In his criticism of AE's approach to allocating marketing and advertising expenses, Mr. Johnson quotes the NARUC CAM pertaining to Sales Expenses in FERC Accounts 911-917. However, given that Witness Johnson is recommending changes to FERC Accounts 908-910, his quotation is not applicable. Pertaining to Customer and Information Expenses in FERC Accounts 906-910, the NARUC CAM states:

> These accounts include the costs of encouraging safe and efficient use of the utility's service. Except for conservation and load management, these costs are classified as customer related. Emphasis is placed upon the cost of responding to customer inquiries and preparing billing inserts.[183]

NARUC appears to agree with AE's cost allocation approach for these expenses. The best measure of customer inquiries and billing related activities is the number of customers on the system. Allocation based on metered customers is a fair and reasonable approach of assigning these costs to each class.

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[183] *Id*. at 103.

(b) Service Connection Fees

While Mr. Johnson proposes that service connection fees be based on a subjective customer based weighting factor for each class, as discussed in Mr. Mancinelli's testimony, the proper way to allocate service connection fees is based on the SMD or customer billed demand allocator. This is similar to the method of allocating services. . Mr. Mancinelli's recommendation recognizes that:

- The cost related to services varies depending upon the size (KW) of the customer;
- Using SMD is an objective method of recognizing this fact;
- Using a customer weighting approach is subjective; and
- Both methods may yield a similar result.

The logic behind this recommendation is simply that service connection fees are related to services, so both service connection fees and services should be functionalized, classified, and allocated in a similar fashion in the COS study.

F. Allocation of Energy Efficiency Service Charge

In the summer and fall 2015, Austin Energy began updating its COS study and starting developing its Tariff Package. One of the company's goals was to redesign two of its pass-through charges in order to decrease the year-to-year variability of the charges, caused in part by customers transitioning between certain rate classes. Part of the strategy of redesigning the EES charge and the Regulatory Charge was to ensure that there was a steady progression of rates from one rate class to the next so that if a customer moved from S3 to S2, for example, the EES charge would not be significantly different. The EES rates that were ultimately developed and presented in AE's January 25, 2016 Tariff Package were not strictly cost-based but did demonstrate a logical progression that mirrored the increasing amount of energy consumed with each higher rate class. This was done to ensure greater stability and predictability to the charge for each customer class and to reduce unintentional year-to-year interclass subsidies caused by customers moving in and out of rate classes.[184]

Following the filing of the Tariff Package, internal review of the Tariff Package's proposals occurred in order for the utility to develop potential compromise proposals should the need arise. Through these meetings, it became increasingly clear that the proposed EES rate would not ultimately meet AE's objective to reduce year-to-year interclass subsidies and therefore, it would not meet AE's desired cost causation outcomes.

In its direct testimony, PC/SC critiqued AE's original EES rate design, claiming that the rates did not align closely enough with true cost of service for several rate classes.[185] AE staff examined the claimed and found evidence which supported PC/SC's critique, although the evidence pointed to a need to more closely align the residential EES rates with their true cost of service, as opposed to PC/SC's supposition that certain commercial classes should have their rates increased. AE filed the Rebuttal Testimony of Deborah Kimberly and proposed an adjustment to the EES fee which brought the rates closer to class cost of service and maintained one of AE's original objectives to provide year-to-year rate predictability.[186]

In response to the new EES proposal, PC/SC, AELIC and ICA propounded several discovery questions on AE regarding the new EES rate. AE responded fully with more than 250 pages of documents to support the responses. Ultimately, in their Briefs, both the ICA[187] and PC/SC[188] excoriate AE for a "dramatic," "substantial," and "late" change to the EES design. The parties had more than a week to review three pages of rebuttal testimony related to the new EES

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[184] AE Ex. 1 at 170.

[185] Public Citizen and Sierra Club's Corrected Position Statements/Presentation on the Issues, PC/SC Ex. 1 at 30.

[186] Rebuttal Testimony of Deborah Kimberly, AE Ex. 7 at 15:15-17:22.

[187] ICA Brief at 70.

[188] PC/SC Brief at 19.

rate design, were allowed to ask and received responses to discovery questions, had the opportunity to cross-examine three witnesses, and now provide final arguments in their briefs. AE refutes any complaint that parties did not have ample time to analyze the proposed rate redesign.

Despite the fact that the actual EES rates generated by the new rate design are outside the scope of this rate review,[189] the ICA spends nearly one-half of the EES section of its Brief lamenting the potential rate increase to residential customers. Similarly, PC/SC's main critique of the redesigned EES rate is of the potential that "residential customers would pay approximately three times the amount as other classes…."[190] The IHE should not base his recommendation on these claims, but instead should only consider the reasonableness of the rate design. In essence, the IHE should rule exclusively on the appropriateness of the allocation methodology and not on any potential rate that results from that allocation.

Since this EES rate review is focused exclusively on the rate design and not the rate itself, it should come as no surprise to any party that AE's intent from the outset was to design a rate that met two objectives: (1) align more closely with costs; and (2) offer predictability for its customers. PC/SC critiqued the allocation of the EES costs in the underlying rate design, and therefore, AE is perfectly entitled to respond to that critique by offering a revised proposal. Not coincidentally, that revised rate design is entirely consistent with the objectives stated throughout this rate review. Because the redesigned rates may shift more cost to the Residential class and

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[189] The EES charge is a component of the Community Benefit Charge. Regarding the Community Benefit Charge, Impartial Hearing Examiner's Memorandum No. 11 limits the scope of this rate review process to whether costs related to costs recovered through AE's Community Benefit Charge are being recovered through base rates and, if so, how should such costs be allocated to the customer classes, and whether such costs are more appropriately recovered through base rates. The actual EES rates generated by the new rate design do not pertain to these issues and, therefore, are outside the scope of this proceeding.

[190] PC/SC Brief at 19.

reduce the costs to commercial classes, advocates for residential customers are vehemently opposed to the proposal. This is not a basis for rejecting a sound cost allocation methodology.

The EES charge funds programs that provide direct benefits to individual customers in the form of rebates and reductions in monthly bills due to lower energy consumption. These programs also provide indirect benefits to all customers in the form of a somewhat lower Regulatory Charge, reduced plant emissions, and decreased capital costs due to offsetting the need for new generation resources. At its core, though, the costs of the EES program are caused by the customers directly participating in EES programs and who directly receive financial and non-financial benefits. The fact that AE has successfully offset more than 400 MW of new demand over a seven-year period is a societal benefit that results from the activities of direct program participants. Even though delaying the need for new resources is a primary goal of the EES programs, these strong program outcomes do not fundamentally drive the cost of the programs: the participants receiving the direct benefits do.

Irrespective of which customer class receives the larger share of direct benefits, AE's EES rate design proposal will align costs with the customers responsible for those costs. Furthermore, AE recognizes that there is year-to-year variability in the proportion of benefits received by different rate classes. Therefore, AE proposes to allocate the EES program costs on a three-year rolling average of total EES costs, divided by the share of residential costs and non-residential costs. The non-residential rate will be adjusted for voltage. This allocation methodology will ensure that if, in the future, the ratio of benefits shifts from one group to another, the EES rate will reflect those changes and will assign the cost to the proper recipients.

Incidentally, AE has shown that residential customers receive a larger percentage of the direct benefits funded from AE's EES charge than commercial customers.[191] Even if multifamily properties are included in the commercial category, residential customers still receive more of the direct benefits. Additionally, no large commercial customer will get "a free ride" on either direct or indirect benefits, contrary to the ICA's claims.[192] Large industrial customers in the P4 and T2 rate classes do not have to contribute into the EES recovery pursuant to tariff design decisions already approved by the City Council. Though these customers will enjoy the benefit of indirect system-wide benefits, their tariffs have been designed to mirror more closely the tariff structures of industrial customers served in the competitive choice areas. This decision was made to help bring the bills of these customers more in line with typical bills in the competitive choice area and was essentially a risk management decision. Moreover, these customers cannot participate in the EES programs because they do not contribute to the program costs. This decision is consistent with the allocation of costs to the direct beneficiaries of the program and is aligned with fundamental cost causation principles.

AE's proposal is reasonable, reflects cost causation principles, and is rooted in policy objectives that have been clear since the beginning of this rate review. AE recommends the IHE adopt the revised EES rate allocation methodology. In the alternative, the IHE could recommend that the City Council require Austin Energy to present the underlying rate calculations during the budget approval process later this summer. This is the time of year when the City Council approves the pass-through charges, and AE could be asked to demonstrate completely the data which support the ultimate EES rates.

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[191] *See* CES Performance Measures Summary, FY 2014 From Customer Energy Solutions Program Progress Report 2014-2015, PC/SC Ex. 29; FY 15 CES Performance Measures Summary From Customer Energy Solutions Progress Report 2015-2016, PC/SC Ex. 30; Tr. at 941:20-943:13; Tr. at 959:10-18.

[192] ICA Brief at 72.

IV. REVENUE DISTRIBUTION / ALLOCATION / SPREAD

Parties do not agree how revenue should be distributed because ultimately the customers that receive the largest share of the revenue spread will receive the largest decrease in their monthly bills. In fact, most all intervenors recommended disallowance of some additional amount of AE's proposed revenue requirement for the self-serving purpose of reducing further the rates they will pay next year. In fact, some proposed revenue requirement adjustments are so extreme they ensure all rate classes could enjoy a rate decrease, even though the evidence indicates that not all rate classes should receive a rate decrease. At the end though, the dispute about the revenue spread has aligned parties into their classic battle lines: residential customers versus commercial customers. As a community-owned utility with goals established by the City Council, AE has attempted to recognize the continuing need to address the interclass subsidy of the Residential class and weigh the affordability concerns for both residential and commercial customers.

When undertaking the initial process to design rates that reduce annual base rate recovery by $17.5 million,[193] AE considered several factors including the current class COS recovery, and implications of proposed changes to pass-through charges. Despite what intervenors Data Foundry/Austin Chamber of Commerce ("DF/ACC") and NXP/Samsung state in their Closing Briefs, Austin Energy did not "turn fundamental ratemaking policies on their head in order to justify artificially low residential rates"[194] or simply "tread water" with respect to interclass subsidies. Instead, AE balanced the myriad financial, political, policy, and community objectives it must meet to develop a reasonable proposal on behalf of all stakeholders and to lay the ground work for future progress toward resolving the disparity in class COS.

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[193] The total amount of revenue to distribute is now $24.5 million with the inclusion of CAP-related revenues.

[194] DF/ACC Brief at 12.

The first objective was to ensure that no increases were imposed on class revenue requirements in the first year of new retail rates (FY 2017). Customer classes below COS were held revenue neutral—except for T2[195]—in order for the community to engage in a substantive dialogue, using the 2014 COS study, about how quickly and how close each class should get to COS.[196] However, because several commercial classes are significantly above COS, the second objective was to deliver the greatest relief to the classes furthest above COS.

To achieve this goal, the S2 and S3 customer classes initially received a $10.1 million reduction in annual base revenues. Of this $10.1 million, S2 received approximately $8.3 million, given its greatest disparity to class COS and the large number of customers assigned to the class. The remaining $7 million reduction primarily benefited the P1, P2, and P3 classes. However, rather than distribute a pro rata share of the reduction to each customer class based on the COS results, AE also acknowledged the impacts of estimated pass-through charges. Austin Energy has proposed a relatively significant change to the Regulatory Charge rate design in an effort to bring the P2 rate class closer to COS. Without any other mitigating efforts, this Regulatory Charge change would likely result in a significant bill increase for P2 customers, an illogical result given the overall context of a revenue decrease. Therefore, P2 received a larger share of the remaining $7 million as an offset to what would have been an overall bill increase.

Generally, parties have not disagreed with AE's proposed $17.5 million revenue distribution. Instead they have focused on further reducing the revenue requirement or on how quickly classes reach COS. Notably, the ICA suggests using a kWh allocator so that all classes can receive benefit from the system-wide rate reduction.[197] AE fundamentally disagrees with this

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[195] In the fall 2015, Austin Energy designed the T2 rates to recover the full COS. By keeping the T2 class at 100% COS, the remaining customer classes are able to receive more immediate benefit from the revenue reduction.

[196] AE Ex. 1 at 024.

[197] ICA Brief at 73.

proposal because the Residential class is already under-recovered by more than $46.3 million with consideration of the CAP revenue adjustment, it should not be entitled to a rate decrease, an action which would exacerbate the disparity in class cost of service.

AE intends to distribute the additional $7 million of revenue related to CAP funds in the same manner as the first $17.5 million: using a balance of financial, community, and technical policies. However, AE has not rerun its COS study to include the $7 million of additional revenue, so class impacts of the additional $7 million are not reported here. AE will rerun the model on request from the IHE and the City Council.

AE acknowledges that the total $24.5 million revenue distribution proposed in this rate proceeding is the next step in the continuing and gradual approach to achieving full COS among all customer classes ("unity"). The first step occurred back in 2012 with the approval of the first new retail rates in nearly 20 years. Austin Energy recommends that additional steps be taken in rate years two (FY 2018) through five (FY 2021) to help bring each customer class closer to unity and to minimize persistent interclass subsidies. AE recognizes that affordability goals and community priorities must be considered in developing the next steps. To assist in that process, intervenors have suggested proposals to address future rate year adjustments in this rate review process.

NXP/Samsung and DF/ACC both recommend that the Residential class be brought closer to COS in the first rate year. In some instances, DF/ACC[198] and NXP/Samsung[199] suggest that all rate classes be brought to unity COS in the first rate year. DF/ACC's vehement assertion[200] that the interclass subsidies have not been addressed by AE or the City Council belies the fact that over the past four years, the Residential class has improved its class COS significantly: in 2009,

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[198] DF/ACC Brief at 9.

[199] NXP/Samsung Brief at 55.

[200] DF/ACC Brief at 11.

the Residential class was under-recovered by over $70 million; in 2014, that figure was $46.3 million. This is due to deliberate and careful efforts of the City and AE in the past two retail rate reviews. The IHE should reject such a dramatic move in the first rate year; instead, AE recommends a continuing effort to move the classes closer to unity over time.

In addition to suggesting an immediate move to class unity, at other instances throughout their brief, DF/ACC appears to suggest that AE adopt a 2% increase for the Residential class in rate year one, in an attempt to keep somewhat consistent with the Council's affordability goals.[201] NXP/Samsung does not support this more moderate proposal as it "allows the existing unreasonable and unfair rate subsidies and burdens to continue into the foreseeable future."[202] The ICA does not specifically address either proposal proffered by DF/ACC, but given its recommendation to enable the Residential class to benefit from some class revenue reduction, the ICA presumably does not support any proposal that would end up increasing Residential class rates.

A 2% increase allocated to the Residential class in one year is inconsistent with AE's guiding principles of utilizing a deliberate, gradual approach to bringing each customer class closer to its COS. The IHE and City Council may want to consider, though, if a 2% or 3% rate increase for residential customers phased in over rate years two through five would be consistent with AE's and the City's principles and policies. Balancing the affordability goals of capping system rate increases to no more than 2% per year and maintaining rates in the lower 50% of Texas utilities requires the City Council to weigh carefully the competing needs of the Residential and commercial classes. As outlined in the initial Tariff Package, the IHE and City

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[201] *Id.* at 13.

[202] NXP/Samsung Brief at 55.

Council have several different policy tools related to moving all customer classes closer to COS to consider.[203]

AE recommends the IHE adopt the proposed revenue spread policy outlined for the initial $17.5 million revenue reduction. Assuming the IHE accepts this proposal, AE will allocate the additional $7 million using these same principles. If the IHE includes other changes to the revenue requirement in his recommendation to City Council, then AE requests the IHE propose an appropriate methodology for allocating the total revenue requirement reduction, including the $24.5 million of revenues already offered by AE.

V. RATE DESIGN

A. Billing Adjustment Factor

A billing adjustment factor accounts for the difference between the amount AE books as revenue and the amount it should have booked based on the billing determinants (*e.g.*, number of customers, kW and kWh) and the prevailing rates.[204] It is a common adjustment in utility cases and accounts for various factors, including errors in prior billings, partial bills, and estimated meter reads. AE calculated a billing adjustment factor in this case on a system-wide basis. This was done because information for calculating it on a class basis was not available. AE Witness Mancinelli admitted that it would be preferable for the billing adjustment factor to be calculated on a class-by-class basis. However, he noted that "AE is not able to calculate reliable, class-specific billing adjustment factors at this time."[205]

NXP/Samsung Witness Goble recommends rejecting AE's proposed adjustment on the grounds that AE purposefully hid the customer class data. However, he provides no evidence of deception to support his accusation. Indeed, Mr. Mancinelli testified that "AE's systems do not

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[203] AE Ex. 1 at 024.

[204] AE Ex. 3 at 51:2-4.

[205] *Id*. at 51:9-10.

allow for accurate base revenue reporting by customer class, in part due to the need to allocate revenues from certain customers on long-term contracts."[206] If such information is available in the future then it could be incorporated into future cost of service studies. However, there is currently not a reliable means to identify the billing adjustment factor by customer class. Regardless, the lack of data to calculate class-specific billing adjustment factors should not result in a complete disallowance as proposed by Mr. Goble. Based on the data currently available, the system-wide billing adjustment factor used by AE is appropriate and should be adopted.

B. Seasonal Power Supply Adjustment

Austin Energy proposes to implement a seasonal PSA instead of charging seasonal base rates. This proposal is supported by the ICA and although PC/SC objects to this approach in its closing brief, PC/SC's argument is based on concern over reducing conservation during the summer, not the appropriateness of seasonal rates in general. No other intervenors took a position on this issue in their closing briefs, suggesting the parties support, or otherwise do not object to, a seasonal PSA.

Austin Energy proposes a seasonal PSA to improve the timely recovery of power supply costs and help maintain pricing incentives consistent with City Council's goals for energy efficiency and conservation. The PSA includes revenues from the sale of power to ERCOT, fuel costs, net Purchased Power Agreement costs, power purchased from ERCOT to supply AE's customer load, and any adjustment for the over- or under-recovery PSA costs balance. The charge is set to recover current year power supply costs, based on the preceding year's expenditures. Because the charge is driven in large part by fuel prices, the underlying cost drivers of the PSA vary with the season. Austin Energy has a summer peaking load, meaning that on a system-wide basis, most electricity is consumed during the summer. As demand

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[206] *Id*. at 51:12-14.

increases during the summer, the power supply is constrained, thus triggering price increases within ERCOT's competitive wholesale power market. Therefore, a seasonal PSA is appropriate because the price of power changes with the season. By adjusting the PSA to reflect this seasonality, AE is able to better align price signals sent to customers with the cost of power supply in ERCOT. AE currently accounts for seasonal power prices by charging seasonal base rates. However, because the seasonal price differential stems from ERCOT's market prices, it is more appropriate to reflect seasonality in the PSA. Austin Energy is thus recommending a seasonal PSA in place of seasonal base rates. These changes are supported by rate design principles, provide incentives for energy conservation, promote the efficient use of resources, and encourage consumer investment in energy efficiency by more accurately reflecting the real-time cost of power.

Austin Energy recommends adjusting the PSA to reflect the two seasonal periods, summer and non-summer. AE is not proposing changing the process for setting the PSA, which is during the annual budget process in the fall. AE will simply set both the summer and non-summer PSA rates simultaneously during the normal budget process, using historical PSA costs. This process protects customers by ensuring that they receive adequate notice of the rates before they become effective, which allows customers to plan conservation measures for summer and calculate a return on any energy efficiency investments. These protections are noted in the ICA's testimony supporting a seasonal PSA:

> High summer bills produce the most difficulties for household budgets, and potentially the elimination of the base rate summer/winter differentiate will moderate bill impacts and reduce customers' need for deferred payment plans. To some extent, this can be viewed as a trade-off between putting the summer/winter differential in the PSA versus base rates. From a costing standpoint, the differential is only related to the production function. 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. 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.[207]

This testimony is consistent with the reasoning behind AE's proposal for a seasonal PSA and evidences the benefit to customers it would create. The ICA repeats this analysis in its post-hearing brief while concluding that it "does not object" to the seasonal PSA proposal.[208]

PC/SC is "concerned that the elimination of the summer rates will decrease the signal to conserve and will reduce investment in energy efficiency measures," and that "[t]he inconsistency inherent in moving the seasonal rate differential from energy rates to the PSA would reduce the incentive to conserve and would confuse customers."[209] PC/SC relies on the statement of its Witness Paul Chernick that reducing summer prices reduces the conservation incentive for summer to argue that "it is most important to send a strong signal to conserve during the summer, when Austin Energy and ERCOT experience the highest demand."[210] PC/SC also notes that its Witness Paul Chernick "pointed out that seasonal energy rates are a better tool to encourage conservation because they give the utility more control."[211] However, PC/SC provided no further discussion as to why or how this is true.

Austin Energy does not agree with PC/SC's position on this issue and finds PC/SC's reliance on Mr. Chernick's testimony in opposing the seasonal PSA misplaced considering Mr. Chernick admitted he has not even examined AE's PSA proposal.[212] Questions on

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207 ICA Ex. 1 at 82-83.

208 ICA Brief at 75.

209 PC/SC Brief at 24.

210 *Id*.

211 *Id*.

212 Tr. at 707:24.

Mr. Chernick's authority to comment on AE's proposed PSA aside, he also testified that in determining whether to incentivize summer conservation or winter conservation, "the question is which of those is more important and which are customers more able to respond to."[213] AE shares the goal of incentivizing conservation with PC/SC and urges the IHE to recognize that doing so at any point in time is important. As Mr. Chernick states, customer response to price differentials must also be considered. Addressing these two objectives—incentivizing conservation while also protecting customers—is precisely why AE is proposing a seasonal PSA in place of seasonal base rates. The ICA correctly pointed out that high summer prices are more difficult for customers to budget,[214] a fact PC/SC itself notes by stating "variation in summer price premium would also leave customers vulnerable to rate shock."[215] A seasonal PSA accomplishes incentivizing conservation during the summer season by increasing prices to reflect the high summer demand in the ERCOT market, but does not create as drastic a change in seasonal prices as accounting for seasonality in base rates. Thus, with a seasonal PSA instead of seasonal base rates, customers' bills will not vary as dramatically with the season and, therefore, be easier to budget for and pay. This will be *less* confusing to customers. AE does not agree that more moderate seasonal price differentials would be *more* confusing to customers as PC/SC suggests. AE also does not agree that the seasonal PSA would not provide adequate summer conservation incentives. Instead, the seasonal PSA creates the right balance of higher prices during high demand periods to encourage energy efficiency measures, but not such varied seasonal prices as to leave customers unable to plan for and afford the higher summer rates. For these reasons, AE recommends the IHE approve a seasonal PSA.

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[213] Tr. at 708:24-709:1.

[214] *See* ICA Brief at 75.

[215] PC/SC Brief at 25.

C. Residential

Austin Energy has proposed changes to its residential rates to ensure greater revenue stability and help prevent potential erosion of the residential class' cost recovery in the future. While there are a number of measures that would help achieve this goal, AE has chosen to only propose adjusting the tiered pricing structure and removing seasonality from base rates in this rate proceeding. AE is not proposing a change to its customer charge, although the COS supports increasing it. This decision is intended to gradually address residential under-recovery so that AE's customers' bills are not significantly negatively impacted but experience only moderate bill impacts.

AELIC is the only intervenor who addressed AE's general approach to residential rate design in its closing brief. AELIC's chief concern seems to be that AE's residential rate design proposal would shift risks from AE to customers.[216] This concern is unfounded. AE's proposed changes to its residential rate design address substantial changes to AE's class load characteristics since its last rate review in 2012. Since then, AE's residential class peak demand has moved closer to the AE system peak while at the same time, there has been a downward trend of average residential energy consumption. The decline has occurred because of successful energy efficiency programs, implementation of the five-tier inclining rate structure, greater multi-family construction than single family dwellings, and more energy efficient building codes. The ultimate result of these shifts is that AE is under-recovering its residential class fixed costs. This scenario is not remedied by the recovery of reconcilable variable costs as AELIC suggests.[217] Indeed, AELIC seems to imply that AE's ability to collect the regulatory charge, the EES, and the street area lighting ("SAL") rates as pass-through charges somehow mitigates AE's need to otherwise recover its residential fixed costs. This is not correct.

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[216] *See* AELIC Brief at 18-20.

[217] *Id*. at 19.

A basic ratemaking principle is that recovering fixed costs through fixed charges more closely aligns the customer's bill with the customer's COS.[218] The TY 2014 COS analysis shows that Austin Energy needs to better align its fixed cost recovery with its fixed revenue stream because 64% of AE's costs are fixed while only 25% of AE's revenue is collected via fixed charges.[219] The remaining fixed costs are recovered through variable charges.[220] AE's proposed residential rate changes are designed to address fixed cost recovery through gradual measures that slowly improve cost recovery alignment while minimizing customer impacts.

1. Customer Charge

Austin Energy is not proposing a change to its residential customer charge in this proceeding. However, AE takes the position that its COS analysis supports an increase to the customer charge. The ICA, PC/SC, and AELIC do not agree with this conclusion.

During the 2012 rate review, AE's residential fixed customer charge was set at $10.00 per month and the electric delivery (or wires) charge, was set at $0.00 per month (i.e., there is no Residential Electric Delivery Charge).[221] Generally, these charges should reflect the minimum amount of equipment and service needed for customers to access the electric grid, since these costs vary with the addition or subtraction of customers and do not vary with energy usage.[222] Austin Energy's Residential customer class has grown by 8.08% since 2009.[223] The fixed customer-related costs have grown at a similar rate, but only 12.5% of these customer-related costs are being recovered in the fixed monthly customer charge.[224] The remaining portion of

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[218] AE Ex.1 at 134.

[219] *Id*.

[220] *Id*.

[221] *Id*. at 144.

[222] *Id*.

[223] *Id*.

[224] *Id*.

customer-related costs is recovered in the variable energy charge within the tiered rate structure, where customer consumption is decreasing each year.[225] For TY 2014, the COS analysis shows AE's total residential fixed costs are $39.27 per customer per month, of which, $21.68 is customer costs and $17.59 is electric delivery costs.[226] The current $10.00 per month customer charge and $0.00 per month electric delivery charge only recover about a quarter of what is identified in the COS analysis.[227]

The ICA and AELIC do not object to AE's proposed $10 customer charge. However, the parties argue that AE is inappropriately including some costs that do not vary with the number of customers in the customer charge and, thus, AE's COS indicating a customer charge greater than $10.00 is incorrect.[228] The ICA also comments that AE's customer charge is higher than other bundled Texas electric utilities.[229] PC/SC supports the $10 monthly customer charge for single-family residential customers but recommends decreasing the multi-family dwelling residential customer charge to $6 because they have a lower cost to serve.[230] PC/SC does not provide any calculations or analysis to support the $6 multi-family customer charge, as noted by the ICA.[231]

AE maintains that its customer charge calculation includes appropriate cost components that do, in fact, vary with the number of customers and that its COS supports a $21.68 customer charge. AE also notes that its $10.00 residential customer charge is less than half of the $22.50 customer charge of the utilities surrounding AE's service territory, Pedernales Electric Cooperative and Bluebonnet Electric Cooperative, which provide a more accurate comparison

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[225] *Id*.

[226] *Id*.

[227] *Id*.

[228] *See* AELIC Brief at 21 and ICA Brief at 77-78.

[229] ICA Brief at 77.

[230] PC/SC Brief at 25.

[231] ICA Brief at 79.

than the utilities cited by the ICA that likely have different cost structures for labor and materials. Additionally, AE urges the IHE to recognize that there is no evidence supporting a $6 customer charge for multi-family dwellings and, as the ICA aptly stated, "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."[232]

2. Tiered Energy Rates

Austin Energy is proposing adjusting its tiered rate structure as a means of improving revenue stability by increasing the bottom tier rate and decreasing the top tier rate. While the ICA recognizes the value of increasing revenue stability, it does not agree with AE's approach to adjusting the tiers out of concern that doing so would result in low-use customers being unable to reduce consumption to lower their electric bills.[233] AELIC and PC/SC object to AE's recommendation regarding its tiered rates over concern that adjusting them will discourage conservation.

Austin Energy proposes to modify its current five rate tiers for residential customers by raising the bottom tier rate and reducing the top tier rate, along with some refinements to the middle tiers.[234] Revenue collection in the lowest rate tier, currently at 1.8 cents per kWh in the non-summer period and 3.3 cents per kWh in the summer period, is unaligned with consumption in this tier: 47.3% of Austin Energy's residential base usage occurs in Tier 1 while only 21.6% of revenue associated with the tiered charges occurs in Tier 1.[235] Significant usage in the upper

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[232] *Id*.

[233] *Id*. at 81-82.

[234] AE Ex. 1 at 025.

[235] *Id*.

tiers must occur to offset the under-collections in the first tier.[236] Because there has been more multi-family construction than single-family construction and energy efficiency programs have succeeded in lowering the average residential customer's energy use, AE anticipates under-recovery in the lower rate tiers to be a growing problem.[237] Additionally, as noted by the ICA, AE's "revenue collections are particularly sensitive to weather conditions with its steeper tiers."[238]

While these adjustments will not change total revenues for the customer class, some customers within the residential class will see bill increases and others will experience bill decreases. Recognizing the importance of gradualism in making rate adjustments, Austin Energy recommends these changes be implemented in year one, prior to assessing any additional charges on the residential class to move the class closer to COS.

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."[239] The ICA is concerned that extreme weather events could push some customers into a higher than usual tier causing "rate shock,"[240] and that low use customers in the first tier who "have little room to further reduce consumption … may be unable to lower their bills in response to the higher rate."[241] The ICA recommends assigning part of the system base revenue reduction to the residential class and using a "portion of the residential share of the base revenue reduction … to fund the changes to the rate structure without increasing rates for the lowest tier."[242]

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[236] *Id*.

[237] *Id*.

[238] ICA Brief at 81.

[239] *Id*.

[240] *Id*.

[241] *Id*. at 82.

[242] *Id*.

Austin Energy shares the ICA's desire to mitigate "rate shock" to customers and is sympathetic to customers who may have less opportunity to reduce consumption in response to higher energy prices. Indeed, moderate customer impact is a key component of AE's residential rate design recommendation. However, some customer impact is necessary to bring the residential rate class into closer alignment with the cost to serve. AE's proposal of creating a more moderate rate structure by moving certain residential class tiers closer to cost of service balances policy priorities of gradual customer impact with appropriate intra- and inter-class subsidies, while achieving greater revenue stability. Therefore, AE recommends the IHE approve AE's proposed modifications to its tiered rate structure.

Additionally, AE urges the IHE to recognize that AELIC and PC/SC's claims that AE's proposal to modify the tiered rates will discourage conservation are baseless. Just as it does now, the tiered rate structure modified according to AE's recommendations will continue to send conservation signals to consumers by increasing the rate with increased usage. PC/SC states "[t]here is no need to cover costs for consumption in each rate tier individually" and that the goal of reducing uncertainty that costs will be covered "should not trump the goal to increase energy conservation."[243] PC/SC also claims that "[a]s a municipally owned utility, Austin Energy operates in a low-risk market and can afford to establish and maintain rates that support other policy goals."[244] First, AE disagrees with the notion that it can "afford" to operate in order to promote certain policies. AE's role is to provide electric service to the City of Austin at reasonable rates, not to charge rates in furtherance of a political agenda. Second, AE's policy goals are dictated by the City Council, not PC/SC. While City Council's policy includes encouraging conservation, it is not the supreme policy driving rates above all others. Rates must be set in accordance with multiple policies, including fair rate class subsidization and alignment

[243] PC/SC Brief at 27.

[244] *Id*.

with cost to serve. Austin Energy's recommended adjustments to its tiered rate structure maintain conservation signals while also more closely aligning prices with the cost to serve to improve revenue stability. This proposal appropriately balances various policy factors and as PC/SC Witness Mr. Chernick admitted, "as long as you're not giving the energy away for free there's some incentive to conserve."[245]

3. Seasonal Base Rates

Austin Energy is proposing to eliminate seasonality in its base rates. As discussed above, AE has determined seasonality is more appropriately reflected in rates through a seasonal PSA. Thus, AE recommends establishing a seasonal PSA in place of seasonal base rates. The ICA does not object to this recommendation, but PC/SC does. No other intervenors addressed this issue in their closing briefs.

Austin Energy based its recommendation to eliminate seasonality in base rates on findings from its COS study that the underlying base rate cost drivers do not vary significantly with the season.[246] This is in part because the base rates recover costs that are primarily fixed in nature and are less influenced by seasonal price volatility.[247] Seasonal base rates have increased AE's financial risk because a large portion of its revenue requirement is designed to be recovered in the summer months, which creates a financial incentive to increase sales while at the same time encouraging its customers to improve their energy conservation efforts.[248] This effect is inconsistent with AE's policies.[249] Additionally, removing the seasonality from base rates will benefit customers by resulting in more predictable monthly bills that are easier to manage

[245] Tr. at 709:18-20.

[246] AE Ex. 1 at 136.

[247] *Id*.

[248] *Id*. at 136-37.

[249] *Id*. at 137.

financially due to less seasonal volatility.[250] In conjunction with eliminating the seasonality in base rates, Austin Energy proposes converting the PSA to a seasonally-adjusted rate.[251] Unlike non-power supply fixed costs, the price of power in the ERCOT market is highly volatile and reflects changes in seasonal demands.[252] AE further discusses the advantages of a seasonal PSA over seasonal base rates in subsection V.C.3 above.

"The ICA does not object to AE's proposal to eliminate the seasonality in base rates and establish a seasonal Power Supply Adjustment."[253] PC/SC, however, opposes AE's recommendation due to concern that "[a]bandoning the summer and winter energy rate differential would risk ending the pattern of increased efficiency that the existing summer tiered energy rates have created."[254] PC/SC asserts that the seasonal PSA "would not provide the consistent signal" to conserve that seasonal base rates provide. AE disagrees with this position. As explained in subsection V.C.3, the seasonal PSA will continue to incentivize conservation by reflecting an increased price during high demand periods, but the seasonal price variation will be less drastic than seasonal base rates, and thus, less financially challenging for customers. For these reasons, AE recommends the IHE adopt the proposal to eliminate seasonality from base rates and implement a seasonal PSA instead.

D. Non Residential Customer Charge

A summary of Austin Energy's proposed non-residential rates can be found in Figures 6.17 and 6.18 of the Rate Filing Package.[255] No parties have objected to Austin Energy's

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[250] *Id.*

[251] *Id.*

[252] *Id.*

[253] ICA Brief at 83.

[254] PC/SC Brief at 28.

[255] AE Ex. 1 at 159.

proposed non-residential customer charges. The ICA is the only party that briefed this issue, however, "[g]enerally ICA does not object to AE's rate design for these classes."[256]

The ICA does not object but merely "has some concern about AE's adherence to strict fixed/variable pricing and the stated desire to pursue pricing which promotes high load factor."[257] According to the ICA, "AE should avoid raising the small commercial customer charge in the next rate review, if possible," and "refrain from shifting costs from energy rates to the demand charge in the next rate review."

While AE notes the ICA's suggestions, AE cannot commit to future handling of individual rate components in the next rate review. Cost elements could change significantly in a future rate case and, therefore, require different treatment. Thus, AE recommends the IHE adopt AE's proposed non-residential customer charges.

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

In its initial Tariff Package, Austin Energy recommended changes to its current Thermal Energy Storage ("TES") tariff.[258] Internally, the TES tariff can be difficult to administer and externally, there are often delays in implementing new TES customers due to the complexity of current processes. Additionally, the current tariff is not well aligned with emerging technologies, like battery storage. To resolve these concerns, AE recommends creating a Load Shifting Voltage Level discount rider for commercial customers that can shift a year-round load using various, non-fuel based storage technologies. PC/SC supports the proposal but advocates several modifications to AE's proposal.[259]

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[256] ICA Brief at 83.

[257] *Id*.

[258] AE Ex. 1 at 156.

[259] PC/SC Brief at 28.

As noted during the cross-examination of AE Witness Mark Dombroski, AE supports PC/SC's call for additional clarification to the name of the rider and to the tariff language in order to elucidate the tariff's intent to address shifts in peak load and not energy reduction.[260] AE also supports PC/SC's recommendation to create a load-shift rider geared for residential customers and to explore other demand response tariffs focused on different storage technologies. However, AE would like to develop pilot programs to test these different ideas and gain a more clear understanding of the benefits and costs of the ideas, how customers would ideally use the tariffs, and the administrative requirements for rolling out full programs.[261]

AE does not support, however, PC/SC's proposal that any storage-related pilot programs be developed with stakeholder, Electric Utility Commission, Resource Management Commission, and City Council participation, except as required by Council policy.[262] Once pilot programs are completed and the data validate the idea's feasibility, AE will consult with relevant stakeholder groups, City of Austin Boards and Commissions, and the City Council prior to rolling out full programs. Pilot programs are addressed in greater detail in Section VII. I.

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

Within AE's initial filing, the demand billing determinates for customers in the S2 and S3 customer classes with less than a 20% load factor were reduced by a greater amount than what would likely be experienced in the rate year. This adjustment was based on aggregated data rather than individual bills. When the proposed rates were applied to the proper billing determinants, it resulted in AE over-collecting its revenue requirement. Unfortunately, it wasn't until the discovery process that AE became aware of this fact. As a result, this error was

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[260] *See* Tr. at 617:9-14.

[261] *See* AE Ex. 2 at 48:18-21, and Tr. at 617:22-618:1.

[262] AE Ex. 2 at 49:1-50:15.

corrected in AE's rebuttal presentation and described in Mr. Dombroski's rebuttal testimony.[263] The revised approximation is based on individual bills of customers with less than a 20% load factor. The energy charges for the S2 and S3 customer classes were recalculated at a 20% load factor to receive their target revenue requirement and reduce the over-recovery produced. The new proposed rates are less than what was proposed in the COS study.

The impact of this adjustment is to reduce the rate year revenue that AE would have collected from the S2 and S3 customer classes. As noted, the initially developed rates would have resulted in an over-recovery. This adjustment is being made to keep AE from over-collecting its proposed revenue requirement. However, it has no impact on AE's overall revenue requirement.

No party opposed this change at the hearing or in their briefs. Indeed, the only intervenor to address this issue in their brief, the ICA, supports the adjustment. Specifically, the ICA noted that this "new provision could mitigate rate shock among certain types of small commercial customers."[264] Additionally, the ICA pointed out that "[s]pecial rates for customers with exceptionally low load factors are justified because the customer's unusual load characteristics are not well suited for demand charge billing."[265] Finally, the ICA indicated that "[t]he 20% load factor floor may also benefit some HOW customers."[266] For all of these reasons, the adjustment is reasonable and appropriate.

G. Group Religious Worship Discount

Following the four-year transition period, Austin Energy recommends that the City Council discontinue the discount for certain group religious worship accounts, commonly called

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[263] *Id*. at 8-9.

[264] ICA Brief at 85.

[265] *Id*. at 85-86.

[266] *Id*. at 86.

House of Worship ("HOW") accounts as intended by the 2012 rate review. Notwithstanding this proposal, Austin Energy understands that this is a policy issue that will ultimately be addressed and decided by City Council. In the event that Council chooses to adopt a HOW discount, AE recommends that it be an extension of the transition period with a specific ending date in order to phase out the discount in a reasonable time period.

Prior to the Council's adoption of the new tariffs in 2012, HOW accounts were typically billed under the residential rate schedule in a rate class identified under the tariffs then in effect as "E01C."[267] Consistent with the design of the residential rate, E01C was an all energy rate. In the 2012 rate case there was recognition and agreement that HOW accounts should be moved to the appropriate commercial customer classes. Additionally, there was concern that special rates for churches were "no longer common in Texas and any such rate treatment would likely be disallowed by the PUC in a rate appeal."[268] A widely discussed precedent was the transition tariff adopted by El Paso Electric in its then most recent rate proceeding before the PUC.[269] Accordingly, in the 2012 case, the City Council adopted a transition policy leading to the eventual elimination of differential rate treatment for HOW accounts.

During the transition period, qualifying HOW accounts were eligible for a rate cap for an electric meter that serves a "religious sanctuary" used primarily for group religious worship services open to the public. The current HOW rate cap is set such that the average rate for monthly service will not exceed $0.13051 per kWh.[270] In addition, billing demand for HOW accounts that are billed demand charges is based on measured weekday demand. The Council

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[267] A HOW account had the option to be served on an applicable commercial rate where that may have lowered the account's total bill.

[268] AE Ex. 9 at 28:9-12.

[269] *Application of El Paso Electric Company to Change Rates and to Recognize Fuel Costs,* Docket No. 40094 (May 23, 2012).

[270] *See* applicable tariff at http://austinenergy.com/wps/wcm/connect/e269c3f9-e09b-40eb-9afc-3b9abc24b67c/SecondaryVoltage.pdf?MOD=AJPERES.

phased in the elimination of the HOW discount upon the conclusion of the next rate review (i.e., the current case). No new HOW accounts would receive the discount after the date of the Council ordinance approved June 7, 2012. Council later voted to extend the HOW discount to new HOW accounts established after the adoption of the June 7, 2012 ordinance.[271]

Two parties, the ICA and Bethany United Methodist Church ("BUMC") addressed this issue. ICA Witness Johnson recommends that the transition to conclude the HOW discount be extended to avoid rate shock. He also recommends that the discount not be discontinued until Austin Energy completes certain customer studies. Also, he recommends that Austin Energy continue outreach to HOWs while those studies are underway, and finally that Austin Energy continue and prioritize outreach to the HOWs with the largest rate impacts.

In his rebuttal testimony, Mr. Dreyfus responded to these arguments. Specifically, Mr. Dreyfus testified that S1 customers are not subject to demand charges, do not incur additional fixed cost recovery, and are unaffected by the change in the S2 class boundary. Only the smallest S1 customers will be affected by the elimination of the rate cap, as the cap is not binding on many S1 customers. Similarly for the S2 class, neither the $2.50 monthly increase in the customer charge nor the expansion of the S2 class contributes to rate shock. In addition, the load factor floor proposed by Austin Energy would have mitigated the rate impact for 78% of HOW S2 bills had it been in effect in the test year. Mr. Dreyfus stated that he anticipates a similar benefit if Austin Energy's rates proposals are adopted. While elimination of the rate cap and including the weekend in billing demand will affect the bills of some S2 HOW customers, Mr. Dreyfus testified that this will not implicitly lead to rate shock for the majority of HOW accounts.

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[271] City of Austin Ordinance No. 20130909-003. *See also* ICA Ex. 1 at 86:4-5.

Mr. Dreyfus also demonstrated that Mr. Johnson's recommendation that the rate cap not be lifted until after the completion of the proposed studies is unnecessary insofar as these studies are unlikely to resolve any perceived concerns of those HOW customers. Mr. Dreyfus also stated that Austin Energy is not opposed to Mr. Johnson's two final recommendations regarding outreach to the HOW accounts and believes that, under current practices, these recommendations are being met today. Lastly, Mr. Dreyfus responded to Mr. Johnson's proposal that AE absorb the discount by pointing out that it is Austin Energy's policy, as adopted by the City Council in the rate proceeding in 2012, that whenever discounts are offered to a set of customers, those discounts are passed back to the customers in the same rate class as the customers receiving the discount.

Mr. Wells, on behalf of BUMC, also recommended extending the transition to the lifting of the HOW rate cap and the inclusion of weekend demand in billing demand be extended until a subsequent rate review. In addition, he makes several other recommendations related to outreach by Austin Energy to the worship community, provision of tools to HOW customers to assist in understanding the impacts of demand, changes to Austin Energy's bill format, and independent review and confirmation of Mr. Wells' rate impact calculations.[272]

Similar to the response to Mr. Johnson, Mr. Dreyfus pointed out in his rebuttal testimony that the HOW discount, like all discounts, is funded from customers in the same class as the HOWs receiving the discount. The transition nature of the HOW discount accommodation assured these customers of the temporary nature of the subsidy they have been required to bear. In addition, Austin Energy has made a significant effort to reach out to HOW accounts to inform them of the Council policy and to provide assistance with energy management including tools and education to help manage their energy use. Furthermore, Austin Energy has been engaged in

[272] Bethany United Methodist Church's Initial Party Presentation, BUMC Ex. 1 at 6.

an enhanced outreach program to HOW customers through our Key Accounts Program. Austin Energy intends to continue this outreach to help provide information and opportunities for energy management services to HOW customers.

In summary, Austin Energy has made significant efforts since the 2012 rate review to provide HOW accounts with information and opportunities to assist in managing their energy costs. There is no COS basis for distinguishing HOWs from other similarly situated customers with respect to the discount policy. Consequently, at the conclusion of this transition period, it is now appropriate to sunset the special rate treatment for HOW accounts.

VI. VALUE OF SOLAR ("VOS") ISSUES

A. Commercial

PC/SC proposes that AE implement a commercial VOS rate in the 2016–2017 Tariffs.[273] AE does not support this proposal and requests that the IHE recommend that Council not consider a commercial VOS at this time.

As observed by the ICA, Ms. Deborah Kimberly, Vice President of Customer Energy Solutions, testified that a comprehensive review of AE's solar rate structures would be necessary before adopting a new VOS, specifically noting that "Austin Energy suggests undertaking a holistic review of both residential and commercial rates and supporting technologies such as smart inverters, panel orientation, storage, and demand response."[274] To address these issues, AE proposes a stakeholder engagement process and the development of a glide path "to prevent sudden changes to customers' bills or utility costs."[275]

Unsatisfied with the AE recommendation, PC/SC continues to urge the adoption of a commercial VOS tariff in this rate proceeding "to fairly compensate commercial customers with

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[273] *See* PC/SC Brief at 29-33.

[274] AE Ex. 7 at 9:22-24.

[275] *Id*. at 10:4-6.

solar installations larger than 20 kilowatts for the energy they provide to the utility."[276] This position is the result of a fundamental misunderstanding about the current commercial solar operations within the AE territory.

As Ms. Kimberly testified during her cross examination by PC/SC, commercial customers are encouraged to size their solar installations so that they meet the customer's daytime load,[277] not so that the customer can feed excess electricity back onto the grid.[278] Because of this underlying assumption about commercial solar installations, simply implementing a commercial VOS without undertaking the necessary inquiries could negatively impact the AE distribution system.[279] PC/SC's explanation in their brief about the precautions taken by AE when working with commercial customers to develop and install their solar arrays does not change this fact.

PC/SC also contends that the commercial VOS must be adopted now because current commercial solar incentives are set to expire before AE will conduct its next rate review.[280] PC/SC's conclusion has two flaws. First, it presupposes that AE will not undertake another base rate review until 2021. While the current City Council directive is for Austin Energy to undertake a COS study at least every five years, as Ms. Kimberly noted in her testimony "the next rate proceeding could occur before or after 2021."[281] This could occur because Council modifies its directive or because the utility determines that a new COS is needed despite the fact that five years have not passed. The second flaw in PC/SC's conclusion is that it ignores the fact

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[276] *See* PC/SC Brief at 31.

[277] Tr. at 911:9-12.

[278] Tr. at 922:15-21.

[279] *See* Tr. at 924:3-4.

[280] *See* PC/SC Brief at 31.

[281] Tr. at 919:3-4.

the VOS question is a narrow and discreet issue that could be handled separately from a full COS review.

Because there has been no comprehensive, stakeholder involved process to review the myriad issues raised by the potential introduction of a commercial VOS, AE requests that the IHE recommend that City Council not adopt a commercial VOS tariff during this rate proceeding.

B. Community Solar

As with the commercial VOS tariff, PC/SC urges the IHE to recommend that Council adopt a value of community solar tariff as part of the 2016–2017 Tariff.[282] AE requests the IHE recommend that Council not adopt a value of community solar tariff at this time because the utility is still undertaking the steps necessary to finalize the design of this brand new offering.

While Austin Energy is working to have its new community solar system operational by the end of 2016,[283] as Ms. Kimberly testified, "the solar installation has yet to proceed through the planning review process at the Development Services Department,"[284] making it harder, if not impossible, to accurately predict when the project will ultimately be online. While AE waits for these bureaucratic issues to resolve, the utility is continuing to engage in an interactive stakeholder process and is working on developing a program that will be most beneficial to its customers. For example, AE has conducted various focus groups and is in the process of conducting a survey to gather feedback about potential compensation options for community solar participants.[285]

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[282] *See* PC/SC Brief at 33.

[283] *See* Tr. at 930:6-7.

[284] Tr. at 930:12-14.

[285] *See* Tr. at 931:9-12.

Despite the uncertain timeframe of approval, Austin Energy is hopeful that the tariff will be developed by the beginning of September.[286] While it is possible that this tariff may include a recommendation for value of community solar, given how many steps must be completed before the implementation of this program, Austin Energy believes that it would be premature for the IHE to make a recommendation to Council about a compensation model for the community solar project.[287]

C. Residential

In his motion to intervene and initial party presentation, intervenor Jim Rourke requested that AE provide additional information about the calculations that go into the VOS residential tariff. In response, AE prepared a table which outlines the various components of the VOS value, their definitions, and the formula used to determine the values.[288] Although the IHE should treat Mr. Rourke's initial party presentation as a statement of position and give it no evidentiary value,[289] at the hearing the IHE admitted the table as Jim Rourke Exhibit 3.[290] AE did not object to the exhibit's admission and intends to include the table in the final tariff package presented to City Council for adoption.[291]

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[286] *See* Tr. at 930:14-18. PC/SC's statement that "Ms. Kimberly testified that Austin Energy plans to take the program design to Council for approval by the start of September, at the latest" mischaracterizes Ms. Kimberly's testimony. Instead, Ms. Kimberly testified that "…it is our hope that no later than the August timeframe, hopefully no later than the very first few days of September, we would have the tariff developed."

[287] AE Ex. 7 at 11:4-8.

[288] *See* VOS Methodology table, Jim Rourke Ex. 3.

[289] *See* Independent Hearing Examiner Memorandum No. 17 at 2-3 (May 31, 2016) ("The Impartial Hearing Examiner noted that for any Statement of Position or any presentation addressing relevant issues in this proceeding that was not supported by a witness would not be considered evidence in the proceeding upon which the Impartial Hearing Examiner could or would base recommendations to the Austin City Council.")

[290] *See* Tr. at 736:15-22.

[291] *See* Tr. at 682:5-15.

AE requests that the IHE recommend that the City Council approve the inclusion of the VOS Methodology table introduced as Jim Rourke Exhibit No. 3 in the 2016–2017 City of Austin Electric Tariff.

VII. POLICY ISSUES

A. Funding Discounts

Austin Energy funds discounts by a separate tracking mechanism or by rolling the discount amount back into its prospective customer class.[292] Although AE proposes several changes to the structure of some of its discounts, it does not propose changing the funding of its discounts. For example, AE proposes changing the ISD discount from 10% off the total bill to 20% off the base rate portion only, but will continue funding the discount by rolling the discount back to the remaining customers in the customer class of the account receiving the discount.[293] The ICA is the only intervenor who raised concerns about how AE funds discounts.

Specifically, the ICA raises the issue of how AE is funding the discount given to outside city ratepayers pursuant to the PUC Docket No. 40627 settlement agreement. The "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,"[294] and claims "it is unreasonable to force inside customers to pay higher rates as a result of the discount."[295] AE strongly disagrees.

The ICA is correct that the purpose of continuing the outside city customer discount is to mitigate the risk of future litigation.[296] However, the ICA mischaracterizes Mr. Dombroski's

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[292] AE Ex. 2 at 12:14-16.

[293] AE Ex. 1 at 171, 173.

[294] ICA Brief at 92.

[295] *Id*. at 93.

[296] *Id*.; AE Ex. 2 at 12:20-21.

testimony on this issue.[297] Mr. Dombroski testified, "[i]f 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."[298] This testimony is not "circular," it is simply describing AE's strategy to protect customers against potential financial risk.

The ICA suggests imputation so that the discount is paid out of AE's margin. However, this would also ultimately result in AE's customers bearing the cost of the discount, which is exactly what the ICA opposes. Paying the imputed revenue out of AE's margin would deplete AE's reserves and working capital.[299] AE would then need to recover these depleted reserve revenues from all customers at a later date.[300] Therefore, customers end up paying for the discount regardless.

Finally, it is not unreasonable to pass this cost to inside city customers since they are the ones receiving the benefit of risk mitigation. An unfavorable PUC decision of an outside city appeal could end up increasing inside city rates even more than the nominal share of the discount. Therefore, AE recommends the IHE recognize that it is appropriate to continue to fund the outside city customer discount as AE proposes.

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[297] ICA Brief at 93.

[298] AE Ex. 2 at 12:21-25.

[299] *Id*. at 13:2-3.

[300] *Id*. at 13:4-5.

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

Austin Energy recommends that the revenue requirement reductions for outside customers that were agreed to during the 2012-2013 PUC proceeding in Docket No. 40627[301] be sustained in this 2016 COS and retail rate review. The basis for the recommendation is the same as the basis for the terms of the settlement in 2013: reasonable public policymaking associated with risk mitigation. The unanimous stipulation in Docket No. 40627 settled all of the parties' issues, resolving the significant uncertainty facing the City because of the litigation. The settlement was deemed reasonable and approved by both the Austin City Council and the PUC, and thus, represents a declaration of public interest by those bodies. Accordingly, Austin Energy recommends that those reasonable terms continue at least until the City's next comprehensive rate proceeding.

The Docket No. 40627 settlement adopted several rate differentials for customers outside the City of Austin. Outside city residential customers received a revenue requirement reduction of $5,425,441. Outside city commercial classes received a base rate reduction of $326,451. The residential reduction was achieved in part by adjustments to the five-tier residential rate structure initially adopted by the City Council. The fourth and fifth tiers were reduced to the same level as the third tier, both for summer and non-summer rates. The summer rate for this combined tier was set above the rate of the third tier for residential customers taking service inside the City. The first tier summer rate was raised as well. Outside residential customers also saw a reduction in the Customer Assistance Program component of the CBC and the removal of the SAL component of the CBC. Outside non-residential classes received various reductions in base rates and the removal of the SAL component of the CBC.

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[301] PUC Docket No. 40627 intervenor Data Foundry, while not a signatory to the agreement, agreed that it would not oppose the issuance of the final order in that proceeding consistent with the terms of the agreement. *See Petition by Homeowners United for Rate Fairness to Review Austin Energy Rate Ordinance No. 20120607-055*, Docket No. 40627, Finding of Fact No. 30 (Apr. 29, 2013).

The terms of the settlement in Docket No. 40627 benefit inside city customers because they reduce the litigation risk at reasonable terms. Maintaining the spirit of a settlement agreement in an effort to avoid a potential future appeal to the PUC, and with it the implicit uncertainty and potential cost of a PUC ruling, is a reasonable public interest strategy. AE recommends the IHE adopt these discounts as part of the overall revenue requirement.

Intervenors Paul Robbins and PC/SC disagree with AE's recommendation. Mr. Robbins bases his opposition on a circumstantial argument that the cost to serve customers situated outside the city limits is in fact higher than the cost to serve customers situated inside the city limits.[302] He also contends that it is unfair for inside city customers to pay for franchise fees paid to other cities inside AE's service territory if outside city customers do not bear the same burden for paying for the General Fund Transfer to the City of Austin.[303] In the alternative, Mr. Robbins recommends that AE no longer pay franchise fees to these other cities should the outside city customer discounts be maintained.

AE has stated that the rationale for maintaining the Docket No. 40627 settlement agreement terms is not cost-based; rather, it reflects a risk mitigation strategy that is in the interest of inside city ratepayers.[304] Mr. Robbins himself acknowledges the fact that the discount is not cost-based.[305] Indeed, Homeowners United for Rate Fairness ("HURF")—the same party that brought the appeal of retail rates to the PUC in 2012—intervened in this 2016 rate review "with its principal [sic] purpose now being to protect the fundamentals of the settlement agreement of 2012 rate appeal to the Public Utility Commission."[306] HURF's intervention

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[302] Testimony of Paul Robbins, Robbins Ex. 1 at 6. *See also*, Tr. at 501:21-502:9.

[303] Final Brief/Response of Paul Robbins at 2 (June 10, 2016) ("Robbins Brief").

[304] *See, e.g.*, AE Ex. 9 at 11:6-12; Tr. at 645:7-16.

[305] Tr. at 501:6-9.

[306] Homeowners United for Rate Fairness at 1 (June 10, 2016) ("HURF Brief").

indicates that this perceived litigation risk is a real concern for AE, and the strategy to avoid another appeal of its retail rates by HURF is a reasonable way to mitigate that risk.

Mr. Robbins' alternative assertion that AE should stop paying franchise fees to other cities in its service territory does not recognize the function franchise fees play in the MOU business model. Franchise fees are a payment for the right to serve residents of a city and are one way to compensate those cities for their lost tax revenues. Because AE is an MOU, it is not required to pay property taxes or other business-related taxes. But, AE is allowed to use right-of-way owned by these other cities for its utility assets. In particular, there are several distribution facilities located in these other cities, and these cities do not have the ability to develop those properties to their highest and best use because of the electric easement on those right-of-way areas. The franchise fee payment is a reasonable way to compensate cities for lost revenues and to pay for the right to serve customers in these outside Austin areas.

AE disagrees with HURF's characterization that the 2013 settlement agreement implicitly "recognized that those [outside city limit] customers do not receive benefit of the utility's revenues transferred to the City's general fund…."[307] But AE also disagrees with Mr. Robbins' assertion that inside city customers do not benefit from the franchise fees paid to cities other than Austin.[308] Notwithstanding this tit-for-tat dispute, AE maintains that both the settlement agreement and the franchise payments are reasonable costs and recommends the IHE adopt them as part of the overall revenue requirement.

PC/SC's opposition to AE's recommendation stems from its desire to restore the five-tier rate structure for outside city residential customers.[309] PC/SC states the five-tier rate structure sends stronger conservation pricing signals than a three-tier rate structure. Consequently, outside

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307 HURF Brief at 2.

308 Robbins Brief at 2.

309 PC/SC Brief at 34.

city customers do not have the same incentive to conserve energy as inside city customers do. Therefore, according to PC/SC, AE should send the same pricing signal to all residential customers by restoring the five-tier rate structure.

PC/SC offers no evidence to support its theory that price elasticity in a three-tier structure is significantly different than a five-tier structure, especially when the rate of incline between the tiers is as high as it is for AE's residential customers. Moreover, while outside city customers pay the same rate for all consumption above 1,500 kWh/ month, outside city customers will pay higher first and third tier rates than inside city customers throughout the year, if AE's proposal is adopted. Therefore, lower usage customers are paying a higher amount compared to inside city customers for similar consumption. The only justification PC/SC provides for its position is the general comments of Witness Paul Chernick, who admitted during cross-examination that he neither aided in the preparation of the testimony nor conducted any quantitative analysis to support his client's positions.[310] Without any evidence to support the claim that outside city customers receive a smaller conservation pricing signal, the IHE should reject PC/SC's recommendation in favor of supporting a risk management strategy that benefits inside city customers.

The ICA filed testimony[311] supporting AE's proposed discount to outside city customers and reiterated its support in its Closing Brief.[312] The ICA does reiterate its recommendation that AE should impute the cost of the discounts to outside city customers rather than including the amount as a cost paid by inside city customers. AE continues to disagree with the ICA's proposal, and addresses these comments in the previous section VII.A.

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[310] Tr. at 711:25-713:2.

[311] ICA Ex. 1 at 21:17.

[312] ICA Brief at 94.

C. Piecemeal Ratemaking

The ICA and NXP/Samsung each raised concerns about the manner in which the City of Austin sets rates for Austin Energy. These concerns were also detailed in the direct testimony of Mr. Johnson and Ms. Fox.

The ICA's position is that the "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."[313] The ICA bases his recommendation on the observation that when rates are adjusted for an expense item outside of a full rate review, there can be "a mismatch…which distorts the overall cost of service."[314]

Austin Energy generally agrees with the ICA. For example, the ICA would be correct in an instance in which the rates for one customer class are adjusted outside of a general rate review, while the rates of other customer classes are not considered for adjustment. That could lead to a distortion in which customers in that one class pay less (or more) than the COS allocated to that class, while other classes continue to pay at the allocated COS. Austin Energy also agrees generally that this concern applies to rates beyond the established pass-through charges previously approved by the City Council. For the PSA, the CBC, and the Regulatory Charge, the tariffs approved previously by the City Council include embedded processes for setting those charges outside of a general rate review.

Notwithstanding, Austin Energy's general agreement, it is important to note that there may be circumstances that warrant making an exception to this policy. For example, this past year the Council deemed that it was in the public interest to change the structure of commercial electric rates outside of a general rate review. This rates policy change altered the rates of many customers. Nevertheless, the Council found this exception to adjusting base rates outside of a

[313] ICA Brief at 94; ICA Ex 1 at 103:17-19.

[314] ICA Brief at 95; ICA Ex. 1 at 102:6-7.

general rate review to be appropriate. In summary, the Council has previously approved processes for adjustments of the PSA, CBC, and Regulatory Charge outside of a general rate review. Those processes are appropriate. While Austin Energy agrees that changes to base rate components and base rate structures outside of a general rate review may lead to distortions from cost of service, there may be exceptions to this policy when the City Council deems such an adjustment is in the public interest on balance.

NXP/Samsung Witness Ms. Fox also argues that piecemeal ratemaking should be avoided and recommends that the Council review a comprehensive recommendation that includes all base rate components and pass-through charges.[315]

Austin Energy is aware of the general concerns about piecemeal ratemaking and understands that electric utilities in the distant past often filed comprehensive rate cases that reviewed all aspects of a utility's COS. As a result of wholesale and retail deregulation, as well as many other changes in electric utility law over the past decade, this is simply no longer the case. The legislature and the PUC allow utilities to set rates for many specific categories of expenses outside a general rate proceeding. These include adjustments to fuel costs, ERCOT fees, and transition charges.[316] In addition, rate changes may be made outside a full rate case to the following rates pursuant to a variety of PUC rules: Fuel Factor (16 Tex. Admin Code § 25.237) ("TAC"); Power Cost Recovery Factor (16 TAC § 25.238); Transmission Cost Recovery Factor (16 TAC § 25.239); Distribution Cost Recovery Factor (16 TAC § 25.243); Advanced Metering (16 TAC § 25.130); and Energy Efficiency Cost Recovery Factor (16 TAC § 25.181(f)).

Similarly, the Austin City Council has defined processes for setting rates to recover specific categories of cost outside a general rate review. For example, the City Council has

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[315] NXP/Samsung Ex. 1 at 10-16.

[316] NXP/Samsung Ex. 1 at 11:15-17.

adopted—most recently in Ordinance No. 20120607-055 and in adopting the unanimous stipulation in Docket No. 40627—such exceptions for the PSA, CBC, and the Regulatory Charge. In each instance, the individual tariff provides specific guidance on how that rate is to be adjusted. For example, the PSA tariff states: "The PSA shall be determined as part of the City of Austin's annual budgeting process, including a public hearing."[317]

In addition to its general concerns about piecemeal ratemaking, NXP/Samsung also argues that the City's budget processes are inadequate for setting pass-through charges as those processes lack the opportunity for discovery and the ability to establish a protective order allowing the public to review confidential competitive information, and that these procedures must be adopted to avoid piecemeal ratemaking.[318]

As noted in Mr. Dreyfus' testimony, the City's budget process is highly participative, and open to public participation and input.[319] As well, members of the public have the right to submit Requests for Information under the PIA. Most importantly, AE's budget and rates are determined by elected representatives of the ratepayers, except for outside city ratepayers who have a right of appeal to the PUC. By virtue of the public's ability to request and review information under the PIA, the City's budget process is fully adequate for setting these pass-through charges under the provisions of the utility tariff.

In summary, the Austin City Council, acting in the public interest as the governing body of Austin Energy, has appropriately adopted several different pass-through charges and established the methods for setting those charges in tariff language. These methods are consistent with the laws and rules pertaining to other utilities in Texas.

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[317] The PSA tariff can be found at http://austinenergy.com/wps/wcm/connect/15f08b08-adca-4050-93fb-e35897369d33/PowerSupplyAdjustment.pdf?MOD=AJPERES.

[318] NXP/Samsung Ex. 1 at 14.

[319] Approved FY 2015-2016 Budget, Vol. II at 675-76.

D. Service Area Lighting

Austin Energy's rate schedules include a tariff for SAL, a cost-based rate that recovers the costs of providing electric service for illumination (*i.e.*, streetlights) and traffic signal service on public streets and highways. The tariff applies uniformly to these services whether those services are provided to accounts inside the City of Austin or outside. For customers inside the City of Austin, the costs to fund SAL are collected through the SAL component of the CBC. Austin Energy does not collect a SAL component of the CBC from customers outside the City of Austin.

AELIC is the only party to address this issue in their brief. AELIC's position is "…that AE should re-allocate its costs underlying its SAL pass through rate to the City of Austin…."[320] Alternatively, AELIC argues that the SAL tariff be found to be "discriminatory and arbitrary."[321] As a third option, AELIC requests the IHE find "that the current SAL pass through tariff be a non-reconcilable rate consistent with the non-reconcilable tariff [AE] uses for its customers outside the Austin city limits."[322] AELIC did not offer any evidence on this issue but cites Mr. Goble's testimony as support for its position. Ironically, NXP/Samsung's brief includes only the following unintelligible statement: "At this time NXP and Samsung found the arguments made by the other Intervenors and therefore support their treatment of Service Area Lighting."[323]

AELIC's recommendation is based upon its belief that the SAL tariff: (1) inappropriately shifts costs onto AE's retailed residential and business customers; (2) is inconsistent with other utilities in Texas; (3) discriminates against inside city customers; (4) exacerbates affordability

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[320] AELIC Brief at 31.

[321] *Id*.

[322] *Id*. at 31-32.

[323] NXP/Samsung Brief at 62.

concerns; and that (5) the costs should be allocated to the City of Austin.[324] None of these arguments, however, provide sufficient support for its recommendations.

With respect to costs causation, cost shifting, and discrimination, Mr. Dreyfus testified that since its founding over 120 years ago, one of Austin Energy's core missions is to provide light and comfort to the public. SAL provides a public benefit, which includes lighting and comfort to the public, but also promotes public safety, crime reduction, and improved access and reduced congestion on roadways. Moreover, the SAL is one relatively small part of a comprehensive evaluation of affordability. Because of the public benefit all customers within Austin receive from street lighting, it is well within the Council's purview to assess customers inside the City of Austin for the provision of this public benefit through the unbundled CBC.[325]

Prior to 2012, street lighting within the City of Austin was funded by Austin Energy as a transfer to the City. In the 2012 rate proceeding, City Council authorized Austin Energy to collect those funds from customers as part of the CBC. This charge improved the transparency of the source of the funding. The Council determined that on balance it is in the public interest for Austin Energy to assess the SAL component of the CBC to fund street lighting in the City.

AELIC also claims that the SAL is inconsistent with other utilities in Texas. However, they presented no evidence as to how the other 150 MOUs or electric coops collect street lighting service in their rates. The sole reference is to Mr. Goble's generalization that other utilities in Texas establish a separate class and base rate.[326] Regardless of how other utilities treat street lighting service, it is well within the purview of the City Council to assess the SAL charge on inside city customers. In its balancing of evidence and policy, the Council determined in 2012 that such a policy is in the public interest. That policy remains valid today just as in 2012.

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[324] AELIC Brief at 29-31.

[325] AE Ex. 9 at 26.

[326] AELIC Brief at 29, citing Samsung Ex. 2 at 11.

Accordingly, the SAL charge should be maintained as in Austin Energy's rate filing recommendations.

E. Power Production Costs and Rate Treatment

There is no precedent on which parties can rely when deliberating about the appropriateness of the retail base rates of a MOU operating in the ERCOT wholesale market. This makes retail rate reviews simultaneously very interesting and very frustrating because each party is trying to carve out new territory in the complex and inherently subjective ratemaking world. Two parties can look at the same facts and arrive at very different conclusions regarding revenue requirements, cost classification, or cost allocation. Take, for example, Data Foundry's ("DF") extreme interpretation of the ERCOT wholesale market regulatory framework and its final recommendation to disallow every single penny of AE's production costs.[327] When no precedent exists to help guide deliberations, wild and inaccurate claims can be made to seem reasonable. It is, therefore, the IHE's role to cut through these kinds of inventive statements to examine the fundamentals of the market structure and the utility's operating practices in order to arrive at a rationale conclusion about the most reasonable method for AE to recover the cost of running the utility.

When there is no legitimate precedence, one naturally turns to alternative examples that may be used to help define an appropriate approach. For example, many intervenors have used the PUC's review of rates proposed by various Texas-based vertically integrated utilities (*e.g.*, Southwest Public Service Co. ("SWEPCO")) as a proxy for how a MOU should be treated.[328] But in each case, these proxy examples fail to adequately capture AE's relatively unique operating environment. SWEPCO, for example, does not operate in the ERCOT competitive

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[327] Data Foundry, Inc.'s Brief on Revenue Requirements at 1 (June 10, 2016) ("DF Brief"). DF/ACC Brief at 4.

[328] For example, ICA Brief at 45-47 or DF Brief at 9.

wholesale market and any reference to how SWEPCO's production costs are viewed by the PUC or classified by the utility itself fails to recognize the massive impact the competitive wholesale market has on AE's operations. A vertically integrated utility like SWEPCO dispatches its generation to meet its system load demand. It is not required to be as instinctively price-responsive as a competitive wholesale generator is in ERCOT; rather, it operates much in the same way utilities in Texas did prior to market deregulation in 1999. But, AE does not operate in this SWEPCO-like way, and parties' reliance on this inaccurate proxy leads them to erroneous conclusions.

Similarly, other parties rely strictly on examples from the competitive wholesale market in an attempt to define the appropriateness of AE's cost of operations. DF's missive, nominally titled, "Revenue Requirements Brief," is really an attempt to frame AE's role in the underlying structure of the ERCOT market as developed and approved by the Texas Legislature in a way that most benefits large commercial customers. While most utilities were broken up into three separate companies—generation companies, wires companies, and competitive retailers—at the time deregulation became effective, MOUs like AE were permitted to continue operations even while having to adapt their practices to meet the new regulatory requirements. The Legislature knowingly approved a market structure that allows MOUs to run their generation business units in the wholesale market and compete against other merchant generation companies. Similarly, the Public Utility Regulatory Act[329] also allows MOUs to continue serving their native loads with a retail operations business unit, albeit in a non-competitive fashion. This legal market structure required AE, in 1999, to re-envision the strategic objectives of each of its three main business units.

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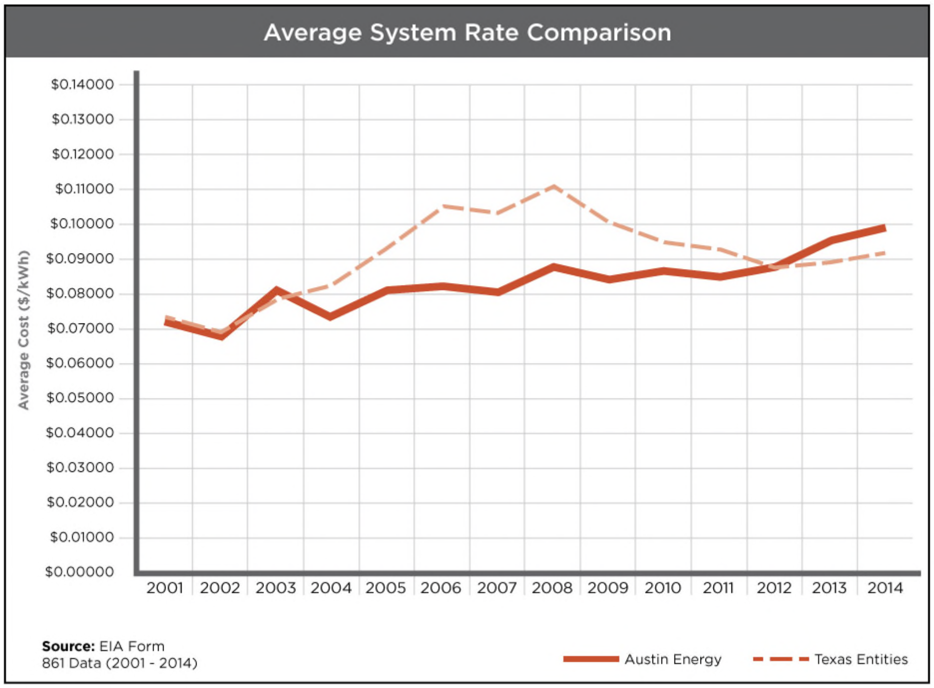
[329] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-66.016 (West 2007 & Supp. 2015) (PURA).

Prior to the introduction of the nodal market in 2010, the company's strategic objectives created a direct causal relationship between AE's generating assets and its customer base. Those assets were built and operated to serve those customers in a manner consistent with the goals and policies approved by the Austin City Council. AE's generation resource fleet was priced in the wholesale market and realized lower than average cost due to the fleet's overall operational efficiency. AE's retail customers enjoyed the direct benefit of lower than average energy costs as compared with retail customers in the competitive market, as evidence by the chart below:[330]



The area between the dotted line (Texas utilities) and the solid line (Austin Energy) represents approximately ten years of savings valued at approximately $1.2 billion AE's customers enjoyed compared with average retail rates in the competitive market during that period.[331] These are the easy to understand, direct benefits of generation owned by AE enjoyed by AE's customers.

[330] AE Ex. 1 at 382.

[331] It is no coincidence that the savings AE's customers realized during this time period corresponded with the time period of normal to high average natural gas prices. When the natural gas market rapidly declined, starting in 2009, the traditional cost-benefit ratio started falling as well.

With the implementation of the nodal market in late 2010, though, that direct, easy to understand relationship between AE's retail customers and AE's generation business unit ("Power Production") operations dissolved. No longer were AE's generation resources directed for use by its retail customers; instead, all energy produced was sold into a centralized, wholesale market and all energy bought was purchased from the same centralized, wholesale market. The relationship between power generation and energy consumption was broken. As with deregulation in 1999, this significant and fundamental change to the market structure altered AE's strategic objectives. AE's Power Production group had to devise a new way to create and measure value for the owners of the generation resource assets because AE's customers were no longer directly tied to AE's resources.

Thus, the parties' debates about short-run versus long-run variable costs or the appropriateness of retail customers paying for wholesale market activity is really a manifestation of the fact that there is no readily identifiable paradigm for parties to use when considering the appropriateness of AE's cost of service study. So, while intervenors struggle to find the correct frame of reference for their analyses, their opposition about the classification of production costs reverts to disagreements over which customer class will pay for which costs. The ICA, for example, disagrees with AE's classification of all non-power supply production costs as demand-related[332] because, ultimately, residential customers will have to pay a higher share of those costs than if the costs were split between demand and energy. That their faulty, supporting rationale results in erroneous conclusions about the most appropriate cost allocation methodology underscores the importance of the IHE's review and final recommendation to City Council. In some aspects, the IHE's recommendation will be first independent examination of the MOU-ERCOT nodal market paradigm.

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[332] ICA Brief at 41-48.

Key to understanding the MOU-ERCOT nodal market concept is the fact that AE's customers are also its owners. While this has always been the case, it has never been more important to highlight the two roles they play. Clearly, for AE's retail customers there is a direct relationship between the cost AE incurs to buy energy from the ERCOT wholesale market and the price the customers pay for that energy. But, less clear to many is the fact that these customers are also the owners of the utility much in the same way that a merchant generation company has shareholders. The shareholders are responsible to pay for the capital infrastructure and operational costs of running the business through contributions of equity. AE's customer-owners are similarly responsible to pay for these fixed production costs; though, they contribute their funds through the base charges on the bill because there are no shares to purchase.

Shareholders of merchant generators receive benefits from the company when the company issues dividends or when share prices rise. These mechanisms to pass on the benefits of owning generation assets do not exist for an MOU's customer-owners: there are no shares or dividends. Instead one of the primary values AE's customer-owners receive is in the form of a revenue stream that can offset the cost of owning and operating the utility. There are other values as well that are outlined by City Council policy, including environmental benefits, emphasis on community-oriented programs, and support of the greater Austin area through sponsorships and fund transfers. For purposes of the rate treatment argument, the remainder of this section will focus on the financial value AE's customer-owners receive.

Because AE's retail customers also own the utility's wholesale assets, the most direct way to causally link the cost and benefits is to recognize the revenues earned from sales of electricity into the wholesale market with an offset to the Power Supply Adjustment paid by customers for wholesale market purchase (among other expenses). The value of this benefit—a revenue stream that can offset the cost of owning and operating the utility—can most easily be characterized as a hedge value.

AE's Power Production group breaks the hedge value into two distinct strategies. First, AE operates the utility's resources to maximize unit availability so that the fleet is ready to run when wholesale market prices merit dispatch. Second, AE attempts to predict when market prices might expose AE's retail customers to unfavorable price volatility. Rapid price escalation is not necessarily the result of high demand, so a crucial component to achieving these strategies is to maximize Commercial Unit Availability ("CUA") throughout the year. Market prices can change dramatically and quickly, and if left exposed, AE's customers could face significant financial risks.[333] The hedge value then results in a separate revenue stream that offsets part of the costs of owning and operating the utility and protects retail customers (who are also the owners) from significant financial risk due to market volatility.

Hedging programs rarely turn a profit because their basic objective is to minimize the potential downside of a transaction. The same is true of AE's Power Production strategies: these resources are not solely focused on maximizing revenue, they are focused on protecting AE's customers from market volatility by being available when prices merit dispatch.[334] Though DF would assert otherwise, AE's Power Production operations is conducted optimally on behalf of its customer-owners with results similar to other generators supplying power to the ERCOT market. That AE may not have earned enough revenue to cover both the variable and fixed costs of owning and operating its generation resources is a result of wholesale market pressure due to historically low natural gas prices, not because of some fundamental problem at AE. In fact, it is a phenomenon being experienced by nearly every competitive generation company in the market

[333] In Subsection II.M.2. of this brief, AE documented that a one-hour event with market prices at the cap could cost AE's customers more than $20 million, payable in two business days.

[334] As noted above, Power Production also has other, non-financial objectives that are included in its strategic planning.

today. The difference between the revenues earned in the market and the revenue required to meet long-term financial investment strategies is called the "missing money" problem and has been debated extensively over the past five years at ERCOT, the PUC and the Texas Legislature. There is nothing unique to AE's performance or to the results of hedging in a historically low market situation. DF's critiques are baseless and need not be considered.

Understanding ERCOT wholesale market fundamentals is critically important to debunk baseless arguments about retail customers in appropriately subsidizing AE's production costs through base rates. Generation resources are offered into a wholesale nodal market that is priced based on short-run variable costs—costs which including fuel, unit start-up costs, and variable operations and maintenance costs ("O&M").[335] Merchant generators (and MOUs with competitive generation business units) typically offer their resources at the short-run variable cost of the generating unit.[336] If a generation company is able to sell energy from that unit for more than the unit's short-run variable cost, then the company can recover some of its long-run costs. Notwithstanding claims made by NXP/Samsung,[337] there is no market guarantee that generators can or will earn more than the short-run variable cost. In the event that they do not earn revenue to cover those costs, shareholders (for merchant generators) and customer-owners (for MOUs) are ultimately responsible to bear those costs.

Despite DF's effort to question the validity of the relationship between AE's retail customers and its wholesale activities, it is clear that AE's customer-owners interact with the utility in a fundamentally different way than do shareholders of a merchant generator or

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335 AE Ex. 3 at 26-27.

336 In the energy-only market, energy offers are ordered from least to greatest costs and the price of the last unit required to meet system demand sets the price for electricity in that moment. Generation companies typically minimize their offer price to include only the short-run variable cost to make it more likely the unit is selected for dispatch. Offers above the short-run variable cost would increase the offer price and make it less likely that the resource would be selected for dispatch.

337 NXP/Samsung Ex. 2 at 41:18-20.

customers of a competitive retailer: AE's customers serve both roles simultaneously. Through this explanation, it becomes evident how the MOU-ERCOT nodal market paradigm has changed the relationship between the utility and its customers, and the determination of the appropriate revenue requirement, cost classification, and cost allocation becomes more clear.

Intervenors have confused the relationship between the utility and its customer-owners because they appear to not understand how an MOU functions in the ERCOT nodal market. This confusion has led to erroneous conclusions about the appropriateness of the revenue requirement and rate treatment. AE's understanding of the market paradigm is clear and reasonable, and thus its recommendations on this cost of service study and retail rate design are appropriate. The IHE should reject DF's and DF/ACC's lengthy and fundamentally flawed critique of the underlying market structure, the ICA's misunderstanding of how production costs are recovered in the wholesale market, and NXP/Samsung's reliance on outdated understanding of what drives the need for CUA. Instead, the IHE should embrace the basic concept of AE's customer-owner and the relationship between the competitive generation company and the retailer. This paradigm most accurately represents the nature of the wholesale market in which AE operates and best captures the inherent relationship between AE and its customer-owners.

F. Studies Supporting Future Cost of Service

Austin Energy proposes certain studies be conducted prior to AE's next comprehensive rate review. The ICA and PC/SC are the only parties who address these proposed studies in their briefs.

AE's proposed studies are listed in Appendix E of the RFP and include studies on the following issues: tier structure of residential rates; lifeline study of minimum residential energy uses; customer-related cost recovery charges for multi-family, single-family, and solar-installed residences; charges for three-phase residential customers; rate structure for secondary voltage service 1; downtown network rates; peak usage measurement; and power factor charges.[338] AE intends to complete these studies before its next comprehensive rate review, however, City Council must grant approval of budgets and procurements.[339]

The ICA recommends that "there should be no change to the House of Worship transition until after the study of weekend demand is completed," and that "AE should provide opportunities for customer involvement in these studies."[340] Specifically, the ICA suggests that AE engage and provide technical expertise during the studies to the Electric Utility Commission and stakeholder groups such as residential consumer advocates, low-income advocates, solar advocates and representatives of ratepayers outside the City.[341]

PC/SC "support[s] a study to evaluate a reduced customer charge for multifamily residents," and "oppose[s] studies focused on customers with on-site solar installations."[342] Also, according to PC/SC, "[b]efore any changes are made to the steepness of the tiered residential rates, a study should be done to examine the impact on energy conservation and low-income customers."[343] Lastly, PC/SC asserts that "[s]tudying the cost of service between serving inside city versus outside city customers is also needed and will help determine to what extent different rate design and structures should be implemented."[344]

Generally, the positions of the ICA and PC/SC are not inconsistent with AE's recommendation. However, AE does not agree that studying residential solar customers "would

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[338] AE Ex. 1 at 372-73 (Appendix E).

[339] AE Ex. 9 at 65:1-5.

[340] ICA Brief at 98.

[341] *Id*. at 99.

[342] PC/SC Brief at 35.

[343] *Id*.

[344] *Id*.

be a waste of money."[345] While it is true that "Austin Energy already has a well-designed method for ensuring that residential solar customers are both compensated for the value they provide and are paying their fair share of costs," AE posits that studies of residential solar customers could help determine how to expand residential solar or how best to develop a commercial solar tariff. Moreover, AE strongly disagrees with PC/SC's assertion that an additional study is needed before reducing the steepness of AE's tiered rate structure.[346] As discussed in subsection V.C.2, AE has already determined that adjusting its tiered rate structure is appropriate.

For these reasons, AE recommends the IHE adopt AE's studies supporting future COS as proposed.

G. Customer Assistance Program

Intervenor Paul Robbins raised the issue of enrollment in the CAP in his motion to intervene and his party presentation/testimony. Mr. Robbins asserts that as currently structured, the CAP Program enrolls certain customers who should not be eligible to receive the CAP discount.[347] To address this perceived deficiency, Mr. Robbins requests that the IHE recommend to Council that the enrollment process involve stricter screening requirements or income verification. He also attached a December 1, 2014 letter to Council to his testimony suggesting some specific modifications to the enrollment process.

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[345] *Id.*

[346] *Id.*

[347] *See* Robbins Ex. 1 at Issue 3: Imprudence in Customer Assistance Program Spending.

AE, along with AELIC,[348] NXP/Samsung,[349] and the ICA,[350] disagree with Mr. Robbins' position. AE requests that the IHE recommend to Council that no changes are currently needed to the CAP discount enrollment process.

As Kerry Overton stated in his rebuttal testimony, for FY 2016, participating AE CAP customers are "eligible for a 10% bill reduction on kWh-based charges…[and]…are exempt from the monthly customer charge and the CAP component of the Community Benefit Charge."[351] Customers qualify for discounts:

> if the customer, or a member of the customer's household, participates in any one of the following programs: the Comprehensive Energy Assistance Program, the Travis County Hospital District Medical Assistance Program, Supplemental Social Security Income Program, Medicaid, Supplemental Nutritional Assistance Program, the Children's Health Insurance Program, the State Telephone Lifeline program, or the Veterans Affairs Supportive Housing program.[352]

SOLIX, the third party vendor, conducts a screening process to identify eligible customers.[353] Since October 2015, this screening process has included reviewing a customer's Travis County Assessment District ("TCAD") Home Improvement Value.[354] If a customer's home improvement value is greater than $250,000, the customer will not be eligible for

[348] AELIC Brief at 32 ("The more credible evidence in the record supports AE continuing to review and analyze its procedures to determine eligibility for its bill discount program; and that an adjustment to CAP costs is not supported by the record.").

[349] NXP/Samsung Brief at 62 ("NXP and Samsung support the recommendation made the Austin Energy Low Income Customer." (sic)).

[350] ICA Brief at 99 ("ICA agrees with the rebuttal testimony of Austin Energy regarding the CAP program.").

[351] Rebuttal Testimony of Kerry Overton, AE Ex. 6 at 6:3-6.

[352] *Id*. at 6:9-15.

[353] *Id*. at 6:18-19.

[354] *Id*. at 7:11-13.

enrollment in the CAP discount program.[355] The list of qualified customers is next sent to Austin Energy which then enrolls the customers, updates the billing system, and then notifies the customers via a letter sent to the billing address.[356] The final enrollment-related step is that one month prior to a customer's annual recertification, AE will send the customer an opt-out letter.[357] The customer "must respond with 30 days to remain enrolled in the CAP discount program."[358]

In addition to making these modifications to the enrollment process, Austin Energy is continuing to evaluate the process and is regularly updating City Council on progress made.[359] AE believes that this incremental process is the correct approach to take and requests that the IHE recommend that City Council take no specific action at this time with respect to the CAP enrollment process.

H. Customer Satisfaction

In the direct testimony of Clarence Johnson on behalf of the ICA, Mr. Johnson raises questions about the customer satisfaction levels reported by Austin Energy customers.[360] The ICA also reiterated these issues in its closing brief.[361] Specifically, the ICA proposed that Austin Energy seek to improve its overall satisfaction rating.[362] AE does not believe that any specific Council action is required with respect to improving customer satisfaction, and as such, requests that the IHE recommend to Council that it need not do anything now on this issue.

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[355] *Id*. at 7:13-15.

[356] *Id*. at 7:1-5.

[357] *Id*. at 7:21-22.

[358] *Id*. at 7:22-23.

[359] *Id*. at 11:5-18.

[360] ICA Ex. 1 at 91:2-93:7.

[361] ICA Brief at 100.

[362] *Id*.

As a customer-owned utility, Austin Energy is always focused on improving customer satisfaction levels. Indeed, as Mr. Overton stated in his pre-filed testimony, Austin Energy has reviewed the data it received from the J.D. Power and Associates survey and is focusing "on the categories where customers reported lower satisfaction levels and [has] set goals to improve the scores in those categories."[363]

It is also important to note that AE receives high customer satisfaction scores when customers directly interact with representatives of the utility.[364] Similarly, "some of the overall satisfaction survey respondents' only interaction with Austin Energy is paying their monthly utility bill, of which electricity is only a part."[365] This limited, monetary-focused interaction would not allow a customer to form a sufficient option about Austin Energy and therefore these customers cannot provide an accurate customer satisfaction response.[366]

Because Austin Energy is actively engaged in addressing customer satisfaction concerns, Austin Energy requests that the IHE recommend to Council that it take no action on this issue at this time.

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[363] AE Ex. 6 at 15:14-23. ("For example, customers indicated that they wanted more frequent communications during outages. As a result of this feedback, Austin Energy is implementing improvements to the outage communication process that will utilize a variety of formats to provide more timely information.")

[364] AE Ex. 7 at 19:4-8.

[365] *Id*. at 19:11-13; *see also* Tr. at 952:13-23.

[366] AE Ex. 7 at 19:13-16.

I. Pilot Programs[367]

Three intervenors, AELIC,[368] the ICA,[369] and PC/SC[370] raised various issues about current and proposed Austin Energy pilot programs. Austin Energy requests that the IHE recommend to Council that no action is needed on any of the pilot program issues at this time.

Both the ICA and AELIC have shared concerns about the current residential prepayment pilot, specifically with respect to the availability of the program to lower income customers and the applicability of the City's regulations to program participants. This limited pilot program was properly adopted by City Council during the last budget process. At the conclusion of the program, it is Austin Energy's intention to review the data and gather all necessary pertinent information about the feasibility of expanding the program. If the utility determines that continuing and expanding this program is something that it believes will be in best interest of Austin Energy's customers, 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."[371] If Austin Energy opts to pursue expanding or extending the prepay pilot program, Austin Energy will take into consideration the various questions and concerns raised by the ICA and AELIC. But it would be premature for Council to take any action on this pilot program as it will close later this fiscal year.[372] Therefore, Austin Energy requests that the IHE recommend that Council take no action on the prepay pilot at this time.

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[367] It is important to note that the pilot programs at issue here were designed and implemented outside the test year and AE has not proposed to include the costs associated with these pilot programs in rates at this time. AE Ex. 2 at 49:6-9.

[368] AELIC Brief at 34-38.

[369] ICA Brief at 100-103.

[370] PC/SC Brief at 36.

[371] AE Ex. 6 at 18:7-10; *see also* Tr. at 886:20-887:10.

[372] AE Ex. 6 at 18:11-16.

PC/SC requested that either Council adopted the new programs proposed by PC/SC or that AE be directed to develop new pilot programs to test new tariffs related to demand response and storage technologies.[373] PC/SC's specific suggestion includes recommendations that Austin Energy create "a special discount for residential users that shifts peak demand using storage technologies and…develop a Demand Response tariff."[374] As outlined in Mark Dombroski's rebuttal testimony, "any new programs will take time and resources to develop and will not be properly developed within the timeframe of the current rate process."[375] Given these facts, Austin Energy requests that the IHE recommend that Council take no action on any additional demand response or storage technology pilot programs at this time.

Finally, AELIC, ICA, and PS/SC all make recommendations that seek to modify Austin Energy's general pilot program development process.[376] For example, the ICA proposes "that stakeholder input should be sought in the development of the pilot, and proposed pilots should reviewed by the Electric Utility Commission and the Council."[377] These proposals are adopted by PS/SC.[378] Because these suggested modifications would negatively impact Austin Energy's ability to timely develop effective pilot programs, Austin Energy requests that the IHE recommend to Council that no action is needed at this time with respect to the pilot program development process.

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[373] PC/SC Brief at 36.

[374] AE Ex. 2 at 48:16-17.

[375] AE Ex. 2 at 48:19-20.

[376] *See, e.g.*, PC/SC Brief at 36 and ICA Brief at 103.

[377] ICA Brief at 103.

[378] PC/SC Brief at 36.

Under the current pilot program development process, Austin Energy will examine goals that City Council has set for the utility[379] or industry best practices and new trends.[380] AE's skilled and experienced staff then develops and implements the pilot program.[381] At the conclusion of the program, "AE reviews the data to see how cost effective the program was, determine the feasibility of the program and its acceptance by customers."[382] If Austin Energy concludes that it would be prudent to implement the program on a large scale, "it is submitted to the Electric Utility Commission and City Council to review, discuss, and approve."[383] By incorporating this more in-depth review process at the back-end of the pilot program development "allows AE to develop programs quickly and test and evaluate them at the cheapest cost."[384]

Moreover, while Austin Energy remains open to receiving feedback and input from stakeholders before a pilot program is expanded and implemented on a utility-wide basis,[385] "[r]equiring Austin Energy to participate in a stakeholder process before even determining if a large-scale implementation of the project is possible would limit the utility's ability to gather concrete data and develop an internal understanding of innovative potential solutions[.]"[386] Because the current pilot program development process strikes the appropriate balance between

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379 AE Ex. 2 at 49:10-17.

380 AE Ex. 6 at 17:6-8.

381 *Id*. at 17:8-15.

382 AE Ex. 2 at 49:21-23.

383 *Id*. at 50:1-2.

384 *Id*. at 50:4-5.

385 It is this broad, utility wide implementation that Mr. Overton was referring to in his testimony when he stated that "Austin Energy is always interested in receiving feedback from its customers and before implementing a new project or program, Austin Energy will…hold discussion about the revisions with the Electric Utility Commission, City Council, and other stakeholders[.]" AE Ex. 6 at 18:6-10. The ICA's characterization of Mr. Overton's testimony is inaccurate. *See* ICA Brief at 103.

386 AE Ex. 6 at 18:1-4.

utility autonomy, stakeholder input, and Council oversight, Austin Energy requests the IHE recommend to Council that no action is needed on this issue at this time.

J. Pick Your Own Due Date

The ICA recommends that Austin Energy be required to implement a "Pick Your Own Due Date" for customers "as soon as it is technically feasible to do so."[387] This option allows AE to offer customers the ability to choose the date within their monthly billing cycle when their bill is due. As noted, AE is working on developing the technical capabilities necessary to offer this option to customers.[388] Specifically, AE witness Overton testified that "[f]for the past six months, Austin Energy has been coordinating with it billing software vendor to determine whether it is feasible to software vendor to determine whether it is feasible to allow customers to select their own due date for their utility bills."[389] Indeed, Mr. Overton testified that AE "anticipates that beginning in October 2016, certain customers will be able to select their own due date."[390] Austin Energy is planning to offer this program to customers who receive monthly assistance from a government program or who are able to demonstrate a hardship. Once the specifics of the program are finalized, AE will publicly announce the program in advance1 of the implementation of the pick your own due date option.[391] Although AE is already actively working to implement this offering, it is possible that technical issues may arise. As such, AE is not in a position to definitively commit to a specific date for implementing the offering and requests the limitation suggested by the ICA be included in any recommendation in order to account for this uncertainty.

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[387] ICA Brief at 104.

[388] AE Ex. 6 at 14; Tr. at 879:9-881:25.

[389] AE Ex. 6 at 14.

[390] *Id*.

[391] *Id*.

VIII. STATEMENT OF POSITION / OTHER ISSUES

On May 3, 10 intervenors filed party presentations. Subsequently, on May 10, seven parties filed cross-rebuttal testimony. Some of this testimony was beyond the scope of the proceeding or was not sponsored by witnesses. Out of an abundance of caution, Austin Energy prepared rebuttal testimony responsive to all parties' presentations. It wasn't until the week before the hearing at the prehearing conference, however, that it was determined which presentations would be offered into evidence and which ones would be submitted as statements of position. Only at that late date did some parties identify their witnesses. As noted by the IHE, these statements of position are akin to protest statements and are, therefore, not included in the record evidence upon which the IHE may base his recommendations. As a result, the statements of position were not identified as exhibits and not offered into evidence. Consequently, although Austin Energy devoted significant time and resources preparing rebuttal testimony to this testimony, it was not offered into the record since it was no longer rebutting evidence from the intervenors.

Similarly, several intervenors devoted significant portions of their time at the hearing and space in their briefs addressing issues raised in their statements of position. Accordingly, there is considerable discussion, but little supporting evidence, with respect to several issues in the case. These facts, not withstanding, the statements of position are valuable nonetheless as they inform the IHE and counsel as to the positions of certain parties. This is particularly true for parties who sought to present their positions without fully participating in the hearing process. Austin Energy expects that the IHE will treat the statements of position properly. However, in the event that information in the statements of the position is relied upon by either the IHE or City Council, Austin Energy respectfully requests the opportunity to have the previously prepared rebuttal testimony responsive to this information considered as well.

This situation also impacted the briefing outline. In preparing the outline, three such issues, late payment fees, regulatory charge, and Data Foundry's power production cost recommendations stood out as issues that were addressed at the hearing but not supported by intervenor testimony. As a result, sections VIII.A (late payment fees) and VIII.B (regulatory charge) are included in the briefing outline. Discussion of the power production cost issues are contained in section VII.E above since NXP/Samsung Witness Goble addressed these issues from a policy perspective and his testimony is included in the record. Finally, AE will respond to issues raised in NXP/Samsung's brief related to the PIA in Section VIII.C below since this is where they included the discussion in their brief.

A. Late Payment Fees

If a customer of a City of Austin utility makes a payment after the due date of the invoice for utility services, the City of Austin assesses a 5% late payment penalty according to City of Austin Code § 15-9-137(c), Payment Requirements and Late Payment Penalty.[392] Section 15-9-137 provides that "except as otherwise limited by contract, if customer care does not receive full payment by the payment due date on an invoice, a 5% late payment penalty shall be added to the invoiced electric, water, reclaimed water, and wastewater charges." The fee is assessed on the customer's next monthly bill invoice for utility services.[393] The late payment fee is a pricing signal used by companies to encourage their customers to pay their bills on time.[394] For the typical Austin Energy residential customer, the approximate nominal amount of a late payment fee that is attributable to the electric service portion of the invoice is $5.00.[395] The fee was adopted pursuant to Austin City Council Ordinance No. 040805-02 and became effective on

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[392] AE Response to AELIC RFI No. 8-15 and AE Response to ICA RFI No. 2-2, AELIC Ex. 32.

[393] *Id*.

[394] *Id*.

[395] *Id*.

August 16, 2004.[396] AE's late payment fee is consistent with the Public Utility Regulatory Act ("PURA") and the PUC's rules regulating the assessment of a penalty on delinquent bills.

AELIC proposes that AE eliminate the late payment fee. According to AELIC, "[t]he more credible evidence" supports eliminating the fee.[397] In the alternative, AELIC urges the IHE to recommend that the late payment penalty not be applied to AE's CAP customers. This alternative recommendation is also supported by the ICA in their brief.[398]

Initially, AELIC provided testimony on this issue. This testimony was rebutted by Mr. Overton. Subsequently, AELIC chose to not offer this testimony. Therefore, Mr. Overton's rebuttal testimony was withdrawn. The remaining evidence on this issue is AELIC Ex. 32, which is Mr. Overton's response to AELIC RFI No. 8-15 referenced above, and a brief portion of the transcript. As such, the *only* evidence in this case supports continuation of the late payment fee as established by City Council.

Utilities, including AE, typically assess a late fee to prompt customers to pay by the due date of the bill. This is an incentive to prevent the customer from incurring unpaid utility balances which increase month over month. Therefore, the ICA's criticism that the fee is not cost based misses the point.[399] The purpose of the fee is to encourage payment of unpaid bills and thereby reduce the amount of uncollectible expense to be collected from other customers.

In support of its position, AELIC argued that "PUC Subst. Rule 28.8(b) does not allow vertically integrated utility to charge its residential customers a late payment penalty fee."[400] AE assumes that AELIC is referring to 16 TAC § 25.28(b). Initially it should be noted that this

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[396] *Id*.

[397] AELIC Brief at 38.

[398] ICA Brief at 104-105.

[399] *Id*. at 105.

[400] AELIC Brief at 38.

regulation does not apply to Austin Energy as an MOU. In Texas, MOUs generally are treated differently than IOUs, especially with regard to customer service and protection rules. The Austin City Council, not the PUC, has the legal authority to allow the City to assess a late payment fee on the utility bill. Because the City Council mandated the assessment of a late payment penalty, Austin Energy must charge customers a 5% fee for late payments, irrespective of what the PUC regulations provide. But, it bears noting that the 5% fee is identical to the one outlined in the PUC regulations.[401]

16 TAC § 25.28(b) permits Competitive Retailers to assess a penalty of up to 5% for late payment. AELIC is correct that this section applies to delinquent commercial and industrial bills. However, 16 TAC § 25.28(i) provides that a 5.0% penalty for late payment may be included in every deferred payment plan offered by an electric utility. This includes residential customers. Similarly, 16 TAC § 25.480(c) provides that a retail electric provider may charge a one-time penalty not to exceed 5.0% on a delinquent bill. The rule goes on to state that no such penalty shall apply to residential or small commercial customers served by the provider of last resort ("POLR"), or to customers receiving a low-income discount pursuant to PURA § 39.903(h). Obviously, this rule does not apply to AE since is not a retail electric provider. In addition, Section 39.903(h) is set to expire next year as a result of legislative action last session.[402]

Contrary to AELIC's inference, Austin Energy's late payment fee is also consistent with PURA § 17.005.[403] That section requires MOUs to adopt rules that have the effect of accomplishing the objectives set out in PURA §§ 17.004(a) and 17.102. Nothing in those

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[401] This remark, which is contained a page 13 of Mr. Overton's rebuttal testimony was withdrawn and is not part of the record. Nevertheless, the ICA incorrectly characterizes Mr. Overton's statement at page 105 of their brief.

[402] *See* Acts 2015, 84th Leg., R.S., Ch. 706 (H.B. 1101).

[403] AELIC Brief at 38.

sections prohibits a MOU from adopting a late payment fee. In its Statement of Position, AELIC claimed that Austin Energy cannot charge its residential customers a late payment fee because regulations adopted by the PUC do not allow a MOU to do so.[404] In its brief, however, AELIC fails to make such an argument. For all of these reasons, it is reasonable for AE to continue to charge a late payment fee to those customers that do not pay their electric bills timely.

B. Regulatory Charge

Shortly after AE's 2012 rate case, many customers switched classes. This migration caused the Primary 3-20 MW ("P2") customer class regulatory charge rate to go from \$2.92 per kW to \$0.38 per kW. This change was compounded after the expiration of the Long-Term Contracts last summer, which was not corrected in AE's budget process last year.[405] This was done so that when customers moved from P1 to P2 they would not experience significant rate impacts.[406] As a result of these shifts, the regulatory charge for P2 customers is currently significantly below cost. AE proposes to redesign the Regulatory Charge "in order to restore a logical rate design for the class at it compares with the regulatory charge assed on the P1 and P3 classes."[407] Left on its own, this change in the Regulatory Charge would likely result in a significant bill increase for P2 customers. In order to mitigate this impact, AE proposes to allocate a larger share of the overall revenue requirement decrease to P2 in order to prevent what would have been a bill increase.[408]

In its brief, Data Foundry has raised concerns over the proposed increase. Admittedly, from a percentage perspective, the prospective increase may be material. However, there are

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[404] AELIC Statement of Position, AELIC Ex. 2 at 7.

[405] AE Ex. 2 at 47.

[406] *Id*. at 48.

[407] AE Ex. 1 at 5-26.

[408] *Id*. at 5-27.

five important considerations that make the rate design adjustment appropriate. First, it should be noted that the regulatory charge contained in the RFP is illustrative and based on the new voltage level approach.[409] Second, even with this increase, the illustrative P2 regulatory charge is still below cost.[410] Third, the rate based on the new voltage level approach is consistent with what the other primary customer classes, Primary <3MW ("P1") and Primary >20MW ("P3"), will be paying.[411] Fourth, the expected change to the P2 charge is not a disproportionate increase on a percentage basis, because, as explained above, the P2 class has been artificially low.[412] Fifth, P2 customers received a larger share of the rate decrease in order to offset what would have been a bill increase.[413] Based upon these considerations, the change to the P2 regulatory charge is appropriate and should be adopted.

C. Miscellaneous Process Issues

NXP/Samsung devotes four pages in its brief to complaining that the inability to access certain confidential information in this case "resulted in a hearing that was not open and accessible" and caused them "to question many of Austin Energy's motives and assumptions…."[414] These same arguments were raised earlier this year when the City created the IHE review process. The City of Austin legal department has made recommendations on these issues that have been considered by City Council. Regardless, it is difficult to respond to NXP/Samsung's claims because they have failed to state any specific relief they are seeking from the IHE or City Council. As a result, Austin Energy will not respond in this brief to each argument raised by NXP/Samsung. Nevertheless, a few points bear noting.

409 AE Ex. 2 at 47.

410 WP H-2.6 shows the COS for P2 Regulatory is $3.61. The proposed rate is $3.16.

411 AE Ex. 2 at 47.

412 *Id*.

413 AE Ex. 1 at 5-27.

414 NXP/Samsung Brief at 63-68.

Initially, NXP/Samsung's assertions are ironic and inconsistent with their desire for electric deregulation and their own role in competitive markets. None of the confidential information NXP/Samsung complains about would be obtainable from any other generator within ERCOT. In fact, no other generator within ERCOT would provide confidential information to the public regardless of their willingness to sign a confidentiality agreement. Indeed, as private entities themselves, NXP/Samsung are well aware that certain confidential information must remain proprietary if they are to remain a viable ongoing entity in a competitive market. Moreover, NXP/Samsung's criticisms reflect a lack of understanding of public power, Austin Energy's unique role in the wholesale market, and regulation at the Public Utility Commission.

As a public entity, the City of Austin is subject to the requirements of the PIA. This act governs the sharing of city-held information. The PIA provides that "information is excepted from the [disclosure requirements of the PIA] if it is information considered to be confidential by law, either constitutional, statutory, or by judicial decision." While much of the information generated, compiled, and held by the City is public information, certain Austin Energy competitive information is deemed confidential by law. As a result of this designation, Austin Energy is precluded from producing this information during a process governed by the PIA.

NXP/Samsung complains that a protective order or a non-disclosure agreement should have been executed by Austin Energy and the other participants in the process to protect confidential information and address the limitations of the PIA. This was not an option however. The City, as an administrative and legislative body, has no authority to issue protective orders. If cities could, it would defeat the purpose of the PIA.

Similar problems exist with non-disclosure agreements. As the Attorney General has opined, cities cannot require the public to sign a non-disclosure agreement as a condition for receiving public information. Even if Austin Energy had the discretion to release competitive matters information pursuant to the PIA, doing so in this proceeding would unreasonably risk the exposure of Austin Energy's proprietary information. The IHE would not be able to enforce any agreement, requiring the City to file a lawsuit in state court. Moreover, Austin Energy has specifically designed this IHE process to be accessible to all Austin Energy customers, including those who might not fully appreciate the importance of a protective order.

Also, the PIA itself provides that if a public entity voluntarily discloses information to one person, the public entity must make it available to any person. The practical impact of this would be to allow anyone, anywhere to access Austin Energy's competitive information. Therefore, it is unreasonable for the City to publically disclose information that could unnecessarily jeopardize Austin Energy's ability to successfully participate in the competitive ERCOT market.

IX. CONCLUSION

In this proceeding, AE initially proposed to decrease its base rates by $17,474,000. After reviewing the party presentations, AE made an additional adjustment of $7,085,000. As a result of this change, Austin Energy is proposing to *decrease* base rates by **$24,559,000**. This is one of several rate reductions Austin Energy intends to implement this year. Austin Energy presented direct testimony and rebuttal testimony in order to demonstrate the reasonableness of its request. In addition, AE responded to over 1,100 discovery questions. As noted in the introduction to this brief, just two parties conducted an examination of AE's revenue requirement. Those two parties, NXP/Samsung and the ICA, propose significantly different revenue requirement and cost allocation recommendations. Only Austin Energy presented a case that attempted to balance the interests of customers, the utility, and the community as a whole.

Furthermore, Austin Energy entered into a deliberative process in order to receive public input into the setting of its base rates. The City of Austin engaged an ICA to represent customers that may not be able to afford representation and hired an IHE to hear the evidence and make recommendations. From a procedural perspective, Austin Energy established a formal proceeding that facilitated input and transparency to give more access and receive feedback from its customers. In that regard, AE is pleased with the level of participation in this lengthy process by all customer segments. Despite criticisms to the contrary, no other similarly situated utility in the state has undergone such a comprehensive or transparent process. Moreover, that transparency exists only because AE remains committed to such goals. Neither independent oversight nor competition would allow for such public involvement.

Finally, AE extends it appreciation to the IHE for his thoughtful consideration of the evidence and patience with this process. AE anticipates a well-reasoned report that will provide guidance to AE and the City Council on providing better service and reaching the proper outcome in this case. In conclusion, AE requests the IHE grant the relief contained in the evidence submitted by AE and summarized in this brief. AE further requests such other relief in law or equity to which it is entitled.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of this pleading has been served on all parties and the Impartial Hearing Examiner on this 17th day of June, 2016, in accordance with the City of Austin Procedural Rules for the Initial Review of Austin Energy's Rates.

HANNAH M. WILCHAR