AUSTIN ENERGY 2022 BASE RATE REVIEW	§ § § § § § §	**BEFORE THE** **CITY OF AUSTIN** **IMPARTIAL HEARING EXAMINER**

RESPONSE OF THE INDEPENDENT CONSUMER ADVOCATE TO THE IMPARTIAL HEARING EXAMINER'S REPORT (EXCEPTIONS)

September 26, 2022

CITY OF AUSTIN 2022 BASE RATE REVIEW

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I. Introduction

The Independent Consumer Advocate ("ICA"), as the representative of the interests of residential and small commercial electric consumers during this 2022 base rate review of Austin Energy ("AE" or "Utility"), takes exception to much of the Final Recommendation issued by the Impartial Hearing Examiner ("IHE") on September 9, 2022 in this matter ("IHE Report"). The ICA urges the City Council to amend or modify the IHE Report as explained herein, in order to better protect all Austin electric consumers from unreasonable electric rate increases.

This rate review comes at a difficult time for many Austinites, to which the public comments received in this proceeding will attest. Inflationary pressures are being felt by residential and small business consumers and many do not feel they have a way to absorb increased living expenses. The housing affordability crisis in Austin is well documented. Electricity is an essential public utility service, closely linked to housing affordability. And the impact this rate review will come on the heels of a potential 70% increase in the PSA surcharge. However, unlike those impacts, the Austin City Council can do something about the size of further base rate increases. When it comes to this base rate review proceeding, the City Council has broad discretion to balance the interests of the electric utility against its citizen consumers.

The ICA is disappointed that the IHE Report sided with AE on most of the revenue requirement issues, as well as on most of the issues related to Class Cost allocations and Revenue Distribution. If followed, those recommendations would place large financial burdens upon residential and small business customers who live within the City of Austin. Even though the IHE largely agrees with the ICA's proposed rate design for residential consumers, that task of implementing a reasonable rate design will be severely complicated if all of the IHE recommendations are followed with regard to revenue requirement.

With the IHE recommendation, the AE base revenue increase would be $31.3 million or **4.9%,** the IHE proposal for the residential class is nearly triple that percentage impact, at $43 million or **14.4%**.[1] In fact, the base revenue increase that would be collected from residential households alone is thus actually $12 million *more than* the total system base revenue increase. In contrast, the ICA concludes that the comparable residential class base revenue increase should only be $6.5 million or **1.2%**.[2]

The ICA's recommendations are guided by accepted utility ratemaking principles, particularly with regard to the goals of maintaining affordability for all Austin ratepayers and ensuring that the electric rates are fair between the various customer classes, and within the residential class. We urge the City Council to amend AE's proposal to increase base electric rates with the ICA's recommended alternatives to the IHE Report, as explained herein.

[1] Based on review of AE's quantification of IHE Report (September 23, 2022).
[2] Exhibit ICA-1, p. 2.

II. Revenue Requirement

AE's originally claimed a rate revenue deficiency of $48,219,749. Based upon its investigation and review, the ICA calculated AE's revenue deficiency as $6,528,255.[3] The IHE report recommendations would allow a total annual revenue requirement increase of approximately $31.3 million. The ICA believes that this amount still significantly overstates the annual revenue needed for the utility.

Below, the ICA explains the revenue requirement issues for which it most strongly disagrees with the IHE report. On some issues, the ICA asks that the City Council adopt the ICA view. On some issues, the ICA suggests a compromise position.

311 Call Center Staffing

As explained by AE in its response to ICA discovery questions, in February 2022, "the Austin City Council approved a new multi-term contract with Howroy-Wright Employment Agency Inc. d/b/a AppleOne Employment for temporary staffing services for the Austin Energy Customer Care team, for up to five years for a total contract not to exceed $68,800,000."[4] As calculated by AE, the annual cost of this contract is $5,382,525 greater than the actual call center staffing expense of $8,372,198 in Fiscal Year 2021. This expense adjustment is 64% over the actual Fiscal Year 2021 expense. The ICA disagrees with AE's contention that full amount of this forecasted increase is a "known and measurable" amount.[5]

[3] Exhibit ICA-2, Schedule DJE-1.
[4] Exhibit ICA-2, p. 11.
[5] Exhibit ICA-2, p. 11.

The IHE agreed with AE on this issue, reasoning that staffing contracts takes time to hire all of the employees contemplated by the contract and that it would be inappropriate to reduce the amount sought by AE while it is still in the process of staffing under the contract. The IHE determined that estimated future increases in staffing levels are known and measurable, because AE "made clear with adequate certainty that it intends to meet full staffing levels".[6]

There is no dispute that AE has stated that "it intends to meet full staffing levels." However, there is no evidence in the record that they are actually doing so. AE was given the opportunity to update the latest known actual staffing levels in discovery and at the final conference in July. AE replied that "There is no update available…".[7] Furthermore, ICA would object to any attempt by AE to claim that updates after the close of hearing support its position. The July hearing (final conference) establishes the evidentiary record in this case, and a fair hearing process should limit AE's ability to rely on additional update evidence, without at least updating discovery responses or providing for the cross examination of AE witnesses regarding such updates.

ICA agrees that an adjustment to the actual staffing expense in the test year is appropriate to the extent that the effects of changes to that expense are actually known and measurable. However, allowing *estimates* of future staffing levels to set electric rates is not a proper application of the "known and measurable" standard. The latest known actual number of employees was 49 fewer than the number of employees assumed by AE in calculating the estimated annual cost of the new staffing contract.[8] ICA continues to contend that the revenue requirement be reduced by $2,880,623 to properly reflect the latest known actual number of employees.

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[6] IHE Report, p. 12.
[7] AE response to ICA RFI 8-1.
[8] Exhibit ICA-2, p 12

Uncollectible Expense

The actual test year (2021) amount of uncollectible expense claimed by AE is abnormally high at $13.9 million, almost three times the uncollectible expense for the previous fiscal year (2020). The COVID pandemic began in March 2020 and continued through the end of 2020 and into 2021. The COVID pandemic caused severe dislocation among AE customers, including loss of employment, inability to work from employers' offices, closure of schools and universities, and staying at home. AE placed a moratorium on disconnections in March 2020, including reconnection of recently disconnected customers. The disconnection moratorium was extended into summer 2021. Furthermore, disconnections were suspended again after Winter Storm Uri.[9]

The IHE agreed with AE and did not accept the argument that the test period was abnormal, stating:

> The IHE largely agrees with AE on this matter. The test year is based on FY 2021, from October 1, 2020 through September 30, 2021. The ICA's proposed three-year average would not include any test year data. While the pandemic's impact began in the first half of 2020, the IHE agrees with AE that the pandemic's impact is continuing and its end is unknown. To a certain extent, the pandemic's effects are long-lasting and can be viewed as the new normal.[10]

The ICA takes exception to this view, given the extensive unusual conditions prevailing during the test year. The ICA continues to believe that a more reasonable approach would be to apply AE's three-year average uncollectible amount, FY2018 - FY2020, as the appropriate level of uncollectible expense.[11] This period is recent and excludes the conditions that affected FY 2021. The three-year average uncollectible amount is $4.574 million.[12] AE continues to request

[9] Exhibit ICA-3, p. 15.
[10] IHE Report, p. 14.
[11] Exhibit ICA-3, p. 16.
[12] Calculation is based on data provided in response to ICA Request 4-8.

$5.99 million annually for uncollectible expense—an amount that is $1.4 million higher than the average for the prior three years. Thus the ICA recommends an amendment to reduce uncollectible expense in the revenue requirement by $1.4 million.[13] AE has not demonstrated that the pandemic did not affect residential uncollectible amounts in 2021, rendering the data unreliable. Therefore, the appropriate remedy is to rely upon uncollectible experience from over the previous three years to adopt a more reasonable projection of future uncollectible costs.

Moreover, the view of AE during the test period in question recognized that it was an unusual and unreliable period of time upon which to base electric rates. See AE's Memorandum sent by General Manager Jackie Sargent to the City Council, dated August 21, 2020 (attached to end of this document), which raised concerns about the abnormal impact that the pandemic was having on the utility's finances at that time.[14]

Heavy Equipment Lease

AE's actual expense for heavy equipment in Fiscal Year 2021 was $5,338,897. Of this amount, $5,275,317 was charged to Account 593 Maintenance of Overhead Lines – Distribution. AE has adjusted the heavy equipment lease expense to reflect the *forecasted* three-year average expense for Fiscal Years 2023 – 2025. The effect of this adjustment is to increase test year distribution O&M expense by $7,407,652.[15]

However, AE has not demonstrated that this three-year average is known and measurable. In response to discovery, AE acknowledged that the projected lease costs for FY 2023-2025 are not

[13] Exhibit ICA-3, p. 16.
[14] https://www.austintexas.gov/edims/pio/document.cfm?id=345962
[15] AE Work Paper D-1.2.12

contractual obligations.[16] Referring to the attachment in the response to ICA Request 2-8, it can be seen that the major increases in the forecasted heavy equipment lease expense are not expected to start until May 2023, which is too remote from the Fiscal Year 2021 test year and too uncertain to be considered "known and measurable," in the view of the ICA.[17]

The IHE agreed with AE, stating:

> Based on the testimony of AE's rebuttal witness, Mr. Dombroski, the IHE agrees that the heavy equipment lease projections out to FY 2025 are known and measurable. According to Mr. Dombroski, the lease sets out the future costs, and the City Council regularly approves the extensions on an annual basis – and has done so since 2007. As a result, while the ICA raises a legitimate concern over such projections, the IHE concludes that the adjustment meets known and measurable criteria as set out in the executed contracts and extensions.[18]

The IHE mischaracterizes the record in this case. There are no "executed contracts and extensions" for the costs subsequent to 2022 contained in the record.[19] *The claimed amounts for FY 2023-2025 are not contractual obligations*. The known and measurable ratemaking principle means that the adjustment to the test year data must be *both* known and measurable. The AE adjustment may be "known" to a minor degree, but the costs for the years 2023-2025 are not known and measurable based on the standard required for setting rates. Forecasts or projections of future amounts are not adequate to make a test year adjustment "measurable." The amount of a known and measurable adjustment must have a reasonable degree of certainty. For this reason, ICA recommended limiting the adjustment to FY 2022 data.

[16] AE response to ICA Request 4-4.
[17] Exhibit ICA-2, pp. 9-10.
[18] IHE Report, p. 16.
[19] AE response to ICA RFI 4-4.

In Fiscal Year 2022, the budgeted heavy equipment lease expense charged to distribution O&M is $5,338,896.96[20]—the only portion of this expense which is truly "known and measurable". This is $7,344,072 less than the projected three-year average of $12,682,969 for Fiscal Years 2023 – 2025. That fiscal period extends four years beyond the test year. The time period used for expenses must reasonably match the time period used for revenues; adjustments based on forecasts extending four years beyond the test year violate this matching principle.[21] Accordingly, the AE revenue requirement should be amended to reduce it by $7,344,072.[22]

Non-Nuclear Decommissioning

Prior to the 2016 Base Rate Review, AE had not been adequately funding the non-nuclear decommissioning fund, which is intended to fund the cost of demolition and removal of non-nuclear generation plants at the end of their useful lives. Based on the ICA's recommendation at the time of that case, and the need to catch up, it was agreed that the annual contribution to the non-nuclear decommissioning reserve be set at $8,000,000 in the revenue requirement. AE has been making that $8,000,000 contribution ever since. ICA believes that the decommissioning fund has now caught up to an appropriate amount, and future contributions can be reduced.

The IHE Report supports the AE proposal to continue the current level of contribution in the current rate review and bases its proposal upon the city's NewGen decommissioning study. However, the utility provided no workpapers or calculations to show how its financial policies or the cost study estimates result in a continued need for an annual contribution of $8,000,000.

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[20] AE response to ICA Request 2-8, Attachment Page 2.
[21] Application of Southwestern Public Service Co. Docket No. 43695 (2016) Order on Rehearing, FOF No. 24A.
[22] Exhibit ICA-2, Schedule DJE-1.

Based on both the estimated cost of decommissioning documented in AE's study and the amount AE has already recovered in rates for non-nuclear decommissioning, $8,000,000 is now well in excess of the appropriate prospective annual allowance for non-nuclear decommissioning.[23] The ICA calculated a mid-point estimate, based on the average of the "Low Range Estimates" and "High Range Estimates" shown in the decommissioning study, resulting in a total of $62.8 million for the three generation plants in the study. This is the best unbiased estimate and most appropriate starting point for the purpose of determining the appropriate annual contribution to the decommissioning reserve.[24]

The rates established in the 2016 Rate Review will have been in effect for six years when the rates in the present case go into effect. Thus, AE will have recovered in rates and funded $48 million (that is, 6 years times $8 million) of the non-nuclear decommissioning reserve as of January 1, 2023. At that time, approximately only $14.8 million of the estimated total decommissioning costs of $62.8 million will remain to be recovered.[25] ICA's expert witness Mr. David Effron recommends that this $14.8 million be recovered over the remaining lives of the non-nuclear generation plants. On DJE-2, he calculated that the average remaining life, weighted by the estimated decommissioning cost of the plants, is approximately 9.4 years. This results in annual non-nuclear decommissioning expense of $1,570,000. To be conservative, he recommends that the calculated non-nuclear decommissioning expense of $1,570,000 be rounded up to $2,000,000 and that this amount be included in the test year revenue requirement. The ICA's proposed adjustment to the non-nuclear decommissioning expense reduces the test year AE revenue requirement by $6,000,000.

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[23] Exhibit ICA-2, pp. 5-7.
[24] Exhibit ICA-2, p. 5.
[25] Exhibit ICA-2, Schedule DJE-2.

AE complained in rebuttal testimony that previous decommissioning cost overruns portend that future decommissioning projects could be higher than expected. However, those very cost overrun experiences have already been taken into account in the outside consultant's decommissioning study.[26]

The IHE Report states that "seeking to fully fund the non-nuclear decommissioning reserve is the best way to mitigate intergenerational equity concerns".[27] However, the referenced NewGen Report does not show how the decommissioning estimates result in an annual cost calculation of $8 million. There is no dispute that fully funding the nonnuclear decommissioning reserve is the best way to mitigate intergenerational equity concerns. That is exactly what the ICA proposal seeks to accomplish. *Over-funding the decommissioning fund will lead to "intergenerational inequity".*

It should be recognized that current customers are already paying for AE's failure to provide any funds for decommissioning prior to its last rate review proceeding. It is unreasonable to further require the present customers fully fund the decommissioning reserve in an arbitrarily short time. The ICA's proposal to reset the annual contribution to the fund at $2,000,000 does the best to match the cost to the consumers who are benefiting, and thus the IHE revenue requirement recommendation should be amended with a $6,000,000 reduction.

Winter Strom Uri and COVID-19 Expenses

In February 2021, "Winter Storm Uri" struck most of Texas, including Austin. This was an extreme storm, rare in terms of intensity and duration. Over 220,000 customers in Austin

[26] Exhibit ICA-2, p. 7.
[27] IHE Report, p. 19.

experienced electric outages for 4 – 5 days.[28] Given the deadly nature of this storm, restoration of electric service was a priority for AE, and it impacted several aspects of AE's operations.

But although this event occurred during the test year, AE's cost of service was not adjusted for Winter Storm Uri to remove the effect going forward. Notably, this event was not a routine or "normal" winter storm and should be considered abnormal for rate making purposes.[29]

AE provided an estimate of $6.8 million for labor and benefits, overtime pay, and contract labor for Winter Storm Uri restoration, which AE said was recorded in March 2021.[30] ICA expert witness Mr. Clarence Johnson recommends amortizing this expense over five years. Regulatory authorities frequently amortize costs caused by extraordinary storms and hurricanes. Generally, the amortization period is intended to represent the interval between events of similar magnitude. Given that the magnitude of Uri is quite rare in central Texas, that approach would imply a lengthy amortization period. Because some normal level of storm restoration costs is likely to occur in the future, a five-year period is a reasonable balance. As a result, the ICA proposed that only $1.36 million of the $6.8 million test year amount be included in cost of service. The difference is $5.44 million, which represents the reduction to the annual cost of service of the utility.[31]

The IHE Report disagreed with the ICA's recommendation; however, it stated that part of the ICA's adjustment could be reasonable:

> The IHE notes that the evidence regarding overtime and contractual labor costs is slightly different than labor and benefits. The ICA points out that 2021 overtime and outside labor expense exceeded average historical experience by an amount approximately the same as the reported Uri restoration cost for those items. The ICA notes that, if the 2017-2020 fiscal years are averaged, the 2021 annual overtime and contract labor exceeds the historical

[28] Exhibit ICA-2, p. 14.
[29] Exhibit ICA-2, p. 14.
[30] Response to ICA Request 4-12.
[31] Exhibit ICA-2, p. 15.

> average by $1.5 and $1.55 million, respectively. These amounts are higher than the reported Uri restoration overtime and outside labor expense.[32]
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> . . .
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> Although the ICA raised reasonable concerns related to overtime and contractual labor costs, the IHE finds that AE established that expenses associated with those outages were not exceptional as compared to other years. As a result, the IHE does not recommend adjusting AE's revenue requirement for storm costs associated with Winter Storm Uri. To the extent that the City Council may disagree, the IHE recommends that any adjustments or amortization be limited to overtime and contractual labor costs.[33]

Therefore, as a compromise on this issue, the ICA urges the City Council to amend the recommended revenue requirement by an amount that at least recognizes the abnormal amount of overtime and contract labor costs, which would result in a reduction of $3,050,000.

Rate Case Expense

AE has included rate case expense of $597,000 in its revenue requirement. This amount was calculated by normalizing total estimated rate case costs of $1,791,000 over three years.[34] However, the last AE rate case was six years ago. Therefore, the ICA recommends a normalization period of at least five years would be more appropriate. Normalizing total rate case costs of $1,791,000 over five years rather than over three years reduces the annual rate case expense by $238,800.[35]

The IHE Report agrees with AE, but the ICA still contends that a five-year amortization better reflects the frequency of AE's base rate reviews. An amendment reducing the revenue requirement by $238,800 is the most reasonable approach here.

[32] IHE Report, p. 21.
[33] IHE Report, p. 22.
[34] AE Work Paper WP D-1.2.7.
[35] Exhibit ICA-2, p. 8; Schedule DJE-1.

Late Payment Fees

This is another issue where the abnormal test period puts consumers in an unfortunate situation. Late payment fee revenues are a reduction to customer costs in the cost-of-service study. Due to the COVID pandemic, late payment fees were suspended for most of 2020 and part of 2021. After late payment fees resumed in 2021, AE continued to encourage payment arrangements that included waiver of the late payment fee.[36] The ICA recommends normalizing this expense using the average annual late payment fee revenue for 2018 and 2019 to set a revenue amount for the cost of service, because the late payment fee revenue in those years should be more representative of future revenues.[37]

AE's late fee revenues declined sharply in 2020 and recovered somewhat in 2021, but not to the level of prior years. The average annual amount of late fee revenue in the two years prior to 2020 is $5.55 million.[38] The test year amount of late payment fee revenues is $3.34 million.[39] On rebuttal, AE proposed a $1.15 million adjustment which estimates late payment fees for months in which the fees were suspended. The IHE Report agrees with AE.[40]

Although this represents movement in the right direction, ICA continues to support the $2.2 million adjustment because the more appropriate basis for estimating future late payment fees is the amount collected in the two-year period prior to the pandemic. Thus, the ICA recommends an amendment that would further increases the offset by $1,050,000.

36 Exhibit ICA-3, pp. 16-17.
37 Exhibit ICA-3, p. 17.
38 AE Response to 2WR 1-11.
39 WP E-5.1.
40 IHE Report, pp. 42-43.

Other Revenue (<u>Facilities Rentals</u>**)**

AE adjusted the actual 2021 test year revenues for facilities rentals, which are included in "Other Revenues," by $1,836,826.[41] AE describes this adjustment as an adjustment to revenue to reflect a change in rental revenue from a particular customer. AE stated that "The adjustment to facilities rental is related to a disputed bill for pole attachments. Austin Energy does not expect to collect payment from this invoice."[42] In response to ICA Request 4-6, AE further stated, that "This is due to the uncertainty of collecting on AT&T pole attachment bills due to an ongoing dispute and negotiations on an expired contract." AE has established that these bills are in dispute. However, this does not establish with a reasonable degree of certainty that there will be no recovery of the balances due.[43] In fact, further discovery indicates that AE is still seeking to recover the amounts in dispute.[44] Accordingly, the ICA recommended that the adjustment to reduce Other Revenues by $1,836,826 be eliminated.[45]

The IHE Report acknowledges that some amount may still be collected by the City, but still sided with AE, stating:

> The IHE recommends approval of AE's adjustment to reduce the Facility Rentals amount. This amount is associated with one customer, has been past due for over a year, and has been adjusted in AE's books. While ICA may be correct that some amount may eventually be recovered, whether or in what amount is not known and AE provided evidence that it followed Generally Accepted Accounting Principles to reduce receivables and adjust revenues.[46]

[41] AE Work Paper E-5.1.2.
[42] Exhibit ICA-2, Attachment ICA 2-11.
[43] Exhibit ICA-2, p. 13.
[44] See Response to ICA Request 8-3.
[45] Exhibit ICA-2, p. 13-14.
[46] IHE Report, p. 43.

It should be noted that GAAP accounting principles are not dispositive of the costs and revenues which the regulatory authority considers for purposes of setting rates. GAAP guidelines are for accounting purposes, and are not relevant for rate-setting purposes.

As a compromise, the ICA urges the City Council to allow approximately one-half of the adjustment proposed by AE, resulting in a revenue requirement reduction of $900,000. There is no dispute that AE is still attempting to recover the fee, or that a new fee may be negotiated in the future. Excluding the total revenue amount, as AE proposes, provides no incentive for AE to aggressively seek recovery of some portion of this fee.

III. Cost Allocation

Cost-of-service studies involve a certain amount of subjective judgment. The IHE Report recommends adopting AE's position on almost all of the issues and sub-issues raised regarding how the utility's cost of electric service should be divided up amongst the various customer classes. [47] The consequences of following such an approach would be dramatic rate shock for many small business and residential consumers. The ICA still stands by each of its recommendations regarding cost allocations.

If, in fact, the City Council adopts all of the ICA's recommendations in this area, the resulting cost study would show that the residential customer class is no longer significantly below the cost to serve them. The ICA's proposed cost-of-service study shows that the residential class

[47] As explained below, the City Council, as the ultimate rate-setting authority, does not need to rely solely on any particular study's view of cost responsibility. At the end of the day, there are a variety of public policy factors, other than cost causation, that should inform the City Council's decisions regarding how costs are to be shared between the industrial, commercial, small business, and residential customers.

relative cost position is *not* above system average.[48] This suggests that AE's proposed base revenue increase vastly overstates its claim that the residential class is heavily subsidized. Furthermore, all studies should be taken with a grain of salt because none of the cost-of-service studies is unambiguously correct. Reasonable arguments can be constructed for multiple methods of dividing up particular costs among customer classes. Indeed, the City Council could examine the results of the different cost of service studies in order to determine a reasonable range of allocation outcomes. As will be discussed in the Revenue Distribution section below, cost study results are only used as a guide in evaluating how any base revenue increase is distributed among classes. Cost studies are but one factor that must be considered by the rate-setting authority.

The ICA urges the City Council to amend the IHE Report to adopt each of the ICA's cost allocation positions. Below, the ICA highlights some of the decisions in this section of the IHE Report that seem particularly egregious from the perspective of residential household interests.

<u>Generation Plant Allocation</u>

The record contains at least three different perspectives from qualified experts on the allocation issue with the largest dollar value, namely, allocating the costs associated with Austin Energy's power plants among the various customer classes. The IHE Report compared the three different proposed methods for allocating this largest category of costs to the various customer classes: a 12CP method, an A&E 4CP method, and a BIP method.[49]

The IHE Report accurately re-states the ICA proposal:

> First, the ICA distinguishes AE from other investor-owned electric utilities in Texas because it is a bundled utility operating in ERCOT. The ICA notes that AE's

[48] Exhibit ICA-3, Schedule CJ-2.
[49] IHE Report, pp. 65-79.

> generation plants each possess distinct fuel and operational characteristics that determine the hours that each plant will operate in the ERCOT market. According to the ICA, however, the primary deficiency of AE's 12CP methodology is that it does not recognize the existence of different types of generation facilities with varying cost characteristics that are critical to the planning and dispatch of generation capacity. The ICA argues that, although the duration of annual energy output is a major determinant of production plant operations in ERCOT, the 12CP method does not recognize the impact of average annual demand on the dispatch of its generation units.
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> The ICA recognizes that the nodal market in ERCOT dictates the dispatch of AE's generation, and that this should be considered in selecting a production allocation methodology. The ICA understands that AE can go to the market to meet its hourly load requirements, even if it has owned generation that is subject to outage or unavailability. The ICA argues, however, that hourly dispatch within ERCOT is driven by generation unit variable cost characteristics, which in turn depends upon the type of generation facility (baseload, intermediate, peak).[citations omitted.][50]

However, even though the IHE describes the ICA's alternative Baseload-Intermediate-Peak (BIP) proposal as a reasonable alternative, the IHE Report recommends adoption of AE's proposed 12CP methodology for allocating the cost of production facilities.[51] This one judgment call would result in allocating 15% more generation power plant cost onto the residential class, shifting a large amount of revenue requirement responsibility onto household customers.

While the IHE acknowledges that both the 12CP and BIP methodologies are reasonable, the IHE stated a preference for 12CP because of AE's sole argument against it—that BIP is not consistent with the operation of power plants in Electric Reliability Council of Texas (ERCOT) market.[52] However, this position ignores the fact that AE's own rate consultant in 2012 issued a report to the Austin Energy Utility Commission (EUC) that recommended BIP, finding that BIP is the method most consistent with the ERCOT nodal market. AE's previous cost-of-service

[50] IHE Report, pp. 67-68.
[51] IHE Report, p. 78.
[52] IHE Report, p. 70.

consultant, R.W. Beck, recommended BIP during the public involvement (PIC) process for the 2011 rate request.[53] The consultant pointed out that BIP is consistent with the characteristics of ERCOT market dispatch.[54] Additionally, AE's rate filing package for the 2016 rate review included a sub-functionalization of production costs for use in a BIP method.[55]

The Texas PUC has never addressed the appropriate production plant allocation method for the current ERCOT market structure. The nodal market in ERCOT dictates the dispatch of AE's generation, a characteristic which should be considered in selecting a production allocation methodology.[56] The hourly dispatch within ERCOT is driven by generation unit variable cost characteristics, which in turn depends upon the type of generation facility (baseload, intermediate, peak). Therefore, BIP allocation is consistent with the ERCOT market structure. Moreover, the ERCOT market structure differs from the regional market structures faced by other bundled investor-owned utilities, such as SPS, SWEPCO, and EPE, which additionally confirms the need for a different production allocation being applied to AE. [57]

Further proving the appropriateness of the BIP method, the ICA produced an analysis which examined margins earned by AE generation in the ERCOT market which demonstrates that the BIP results are indeed consistent with ERCOT operations.[58] AE erroneously characterized this ICA analysis, claiming that it is based on generation plants serving AE's system demand, rather than reflecting ERCOT actual pricing and demand.[59] This is false. ICA's ERCOT BIP analysis

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[53] Exhibit ICA-15 (RW Beck Report), p. 198-203.
[54] R.W. Beck concluded that BIP mirrored the Probability of Dispatch method (POD) by "maintaining a link between resource dispatch and load requirements, but in a manner more consistent with the ERCOT nodal market design." Ibid., p. 199-200.
[55] 2016 COSS WP F-2.3
[56] Exhibit ICA-3, pp. 19-20.
[57] Exhibit ICA-4, pp. 4-5.
[58] Exhibit ICA-3, pp. 24-25.
[59] Exhibit ICA-3, p. 25.

is based on the weighted average settlement price for nuclear, coal, combined cycle, and combustion turbine plants in the ERCOT market.[60] Therefore, the ICA analysis reflects the operation of AE's power plants based upon ERCOT demand and market prices. The results of ICA's analysis of AE's power plant margins in the ERCOT market substantiates ICA's BIP allocation methodology. AE's misunderstanding of ICA's methodology led to the incorrect conclusion by the IHE that BIP is inappropriate for allocating plants in ERCOT. The ICA urges the City Council to amend this decision and adopt ICA's version of the BIP production allocation method.

Bad Debt Expense Allocation

On another allocation issue, the IHE accepts AE's position that bad debt (uncollectible) expense is related to the customers function, and should be directly assigned to each customer class. Alternatively, the ICA recommends a base revenue allocation of bad debt expense among the customer classes.[61] The Texas PUC has historically allocated this cost on a revenue basis, as the ICA is recommending. The reasoning of the Texas PUC is that bad debt expense is a social cost which is not causally related to any customer currently on the system. That reasoning was thoughtfully explained in an Entergy rate case (Docket 16705) and has been consistently reaffirmed by the state's regulatory commission:

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

[60] Exhibit ICA-3, p. 25.
[61] Exhibit ICA-3, p. 40, footnotes 36, 38.

> jurisdictional and class levels on the basis of jurisdictional and class operating revenues.[62]

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

To the contrary, the IHE apparently accepted AE's position that Docket No. 16705 is "outdated" precedent (1998), and did not follow it.[63] In doing so, the IHE overlooks the fact that the Texas PUC reiterated its adoption of revenue allocation of bad debt expense in a 2016 SPS rate case order (Docket No. 43695). [64]

The SPS case is the only PUC proceeding in the last 10 years in which this bad debt allocation issue was litigated, and thereby reaffirms the continuing validity of the PUC precedent in the Entergy case, Docket No. 16705. The Administrative Law Judges in SPS Docket No. 43695 concluded that "Commission precedent shows that these costs have typically been allocated to each class by its revenue requirement, with the Commission explicitly noting the unfairness…of allocating these costs directly to the classes to which the non-paying customers belonged."[65] Notably, the IHE has approved the ICA's recommendation regarding load dispatch allocation, which was based on the same 2016 SPS rate case order (Docket No. 43695).

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[62] Entergy Gulf States, Inc., Docket No. 16705, Second Order on Rehearing at Finding of Fact No. 231 (Oct. 14, 1998).

[63] IHE Report, p. 56.

[64] Application of Southwestern Public Service Co. for Authority to Change Rates, Docket No. 43695, Order on Rehearing, FOF 310 and 311 (Feb. 2016).

[65] Application of Southwestern Public Service Co. for Authority to Change Rates, Docket No. 43695, Proposal for Decision at 253.

The ICA believes that the same consistency with Texas PUC precedent should be applied to the uncollectible allocation, and urges the City Council to amend the IHE recommendation on this sub-issue. Treating bad debt as a social cost which should be spread to all customers reduces Residential cost of service by approximately $3 million.

Customer Service Expense Allocation

The ICA takes exception to a third sub-issue with the Cost Allocation section of the IHE report, relating to certain Customer Service Expense" (Accounts 911-917).[66] This allocation issue involves $28 million of expense. AE allocates these costs based upon number of customers in each class, which means almost all of such cost is allocated to the Residential Class. ICA recommends allocating these expenses upon the basis of each customer class's share of revenue requirements. The FERC Accounting system specifies that expenditures recorded in these accounts are for activities aimed at influencing or promoting customers' energy usage. The NARUC Electric Cost Allocation Manual states that such costs should <u>not</u> be allocated based on a number of customers, and that a broad allocation such as revenue requirement should be utilized.[67] The ICA notes that FERC Accounts 911 – 917 comprise 61% of the total Customer Service expense; therefore, the Customer Service allocation factor should reflect a 61% weighting to the Revenue Requirement allocation and 39% weighting to the Customer allocation factor.[68]

[66] IHE Report, p. 89.

[67] For Accounts 911 – 917, the NARUC Electric Utility Cost Allocation Manual states:
Allocation of these costs, however, should be based upon some general allocation scheme, not numbers of customers. Although these costs are incurred to influence the usage decisions of customers, they cannot property be said to vary with the number of customers. These costs should be either directly assigned to each customer class when data are available or allocated based upon the overall revenue responsibility of each class. (NARUC CAM at 104; Exhibit ICA-11).

[68] Exhibit ICA-3, pp. 49-50.

ICA's recommendation is exactly consistent with the NARUC CAM's instruction, while AE's allocation proposal does exactly what the NARUC CAM says not to do.

The IHE accepts AE's argument that most of the activities in these accounts are aimed at influencing residential customer use of electricity, and therefore concludes that AE's allocation should be adopted. Even if AE is correct that the advertising is targeted at residential customer usage, the IHE reasoning does not support allocating almost all the cost to residential users. For cost causation determination, the important issue is the purpose and objective of the expenditure, not the target audience for the advertising. AE should be undertaking activities aimed at influencing customer usage only if the action benefits the system as a whole. The purpose of such advertising and other activities aimed at affecting energy use is to reduce the utility revenue requirement for everyone on the system. These costs should be allocated in a similar way to AE's allocation of Energy Efficiency costs, which are not assigned to the "targeted" classes, but is instead allocated among customer classes on a revenue requirement basis. The ICA urges the City Council to amend this sub-issue decision of the IHE Report to follow the NARUC manual method for Account 911-917 costs. Adoption of ICA's position on this issue reduces the Residential class revenue requirement by approximately $8 million.

IV. Class Revenue Distribution

The discussion above regarding cost-of-service studies is only one piece of information pertaining to the proper distribution of the revenue increase among customer classes. Perspectives on cost causation are only the first step in determining the most reasonable distribution of revenue requirements to the various sized customer classes. Rate impacts, non-cost considerations, promoting efficient behavior, and other public policy concerns are also relevant factors.

While the IHE does recognize that non-cost factors should be considered, ultimately, he endorses the AE revenue allocation method which is to move classes 50% in the direction of cost (towards AE's subjective view of cost responsibility).[69] The ICA disagrees and urges a compromise approach. Rate moderation is essential for the proper apportionment of revenue increases among the various customer classes. There are extreme variations in revenue-cost positions between the customer parties in this case. That wide difference in perspective should give the City Council pause. The ICA counsels caution when those studies suggest such dramatic differences in the distribution of costs from one class to another.

Furthermore, the quality of the test period (test year) data examined in this case has been called into question. This period includes the later stages of the COVID pandemic shutdown, which produced significant economic impacts, and thus such related anomalies are embedded in the data. The COVID pandemic is an exceptional circumstance, which affected many customers' ability to pay and likely constrained growth in the billing determinants for some customer classes. AE did not attempt to normalize the energy and demand allocation factors which divide most of the costs among the customer classes. Yet the evidence indicates that the COVID pandemic likely increased the allocation factors for the residential class and reduced the allocation factors applied to commercial classes.[70] As a result, the potential arises that future customer class composition and the capacity for revenue generation will vary significantly from the results of the test period examined in this rate review.

[69] IHE Report, p. 94.
[70] Exhibit ICA-3 at 54-55.

Class cost of service studies are imprecise instruments. The studies will allocate costs to a multiple decimal point level, but this may provide a false sense of security about the accuracy of the studies. While class cost-of-service studies provides useful information for developing the class revenue increases, they should not be the sole consideration. This principle has been recognized in longstanding regulatory texts, such as Dr. James Bonbright's seminal *Principles of Public Utility Rates*.[71]

From its earliest history, the Texas PUC has recognized the principle that cost study results need to be subject to rate mitigation.[72] The Supreme Court of Texas itself has granted broad discretion to utility regulators when considering customer class allocations and rate design. The case Texas Alarm & Signal vs. PUC (1980)[73] stands for the proposition that the rate-setting authority may exercise broad discretion in allocating utility revenue increases among customer classes and types of service. In that case, the Supreme Court said that to blindly follow one utility cost study methodology "assumes the existence of a structured world with only black and white and no gray. . . . and that the adjusted value of property could be allocated in an unquestionably uniform manner. . . [Plaintiff's proposal] would require arbitrary allocations based on a multitude of assumptions. Such assumptions would be subjective and not universally accepted."[74]

Therefore, the City Council, as the regulatory rate-setting authority, is under no obligation to set prices based on any particular cost methodology, because it has the discretion to consider other factors and public policies that are important in determining rates. The City Council is not

[71] James Bonbright, *Principles of Public Utility Rates*, Chapter 16, "Criteria for A Sound Rate Structure," (Columbia Press) (1961).
[72] Exhibit ICA-3 at 54.
[73] https://law.justia.com/cases/texas/supreme-court/1980/b-8620-0.html
[74] Texas Alarm & Signal vs. PUC, **603 S.W.2d 766, 772 (1980).**

bound to pursue a particular percentage movement toward the adopted class cost of service study, as AE claims. The City Council has the authority to amend the IHE Report to adopt the ICA's revenue distribution recommendations. Some factors that should be taken into consideration for class revenue distribution include housing affordability (which is affected by electric bills), the impact of the pandemic and Winter Storm Uri on customer class usage, and the ability of households to afford the rate increase.

Instead of moving a specific percentage toward cost of service, the ICA offers a more appropriate and moderate methodology: The first step is to apply a percentage increase one-half of the system average to customer classes which otherwise would receive a revenue reduction. The second step is to distribute the remainder of the base revenue increase on an equal percentage basis to the remaining customer classes. Based on ICA's revisions to the CCOSS, Secondary classes <10 kW and 10 – 300 kW would otherwise receive a revenue reduction.[75]

This approach suppresses large impacts, broadly shares the revenue increase, and recognizes classes with revenues substantially above cost. No customer class receives a revenue reduction, and the remaining classes pay an equal percentage of the remaining system revenue increase. The ICA urges an amendment to the ICA Recommendation that applies this approach to class revenue distribution.

[75] Exhibit ICA-3, Schedules CJ-3 and CJ-4.

V. Rate Design

AE's proposed rate structure for residential customers is radical and likely to cause dramatic rate shock for Austin households that use less than the average amount of electricity. The rate shock will be particularly acute if the City Council sides with the AE on the overall size of the revenue requirement and regarding the proposed shift of significant costs upon the residential customer class. Unless properly mitigated, the combined impact of these base rate proposals (all opposed by the ICA) would be felt most severely by *low usage customers*, with percentage impacts as high as 50%.

,The following chart[76] for Inside City rate increases based on ICA's proposal compared to AE's rate design with the IHE revenue requirement, shows the wildly divergent impacts that are likely based upon differing usage levels:

	ICA-Proposed Rate Design		**AE Rate Design IHE Rev**	
kWh	Increase	Percent	Increase	Percent
375	$ 0.59	1.56%	17.71	46.9%
625	$ 1.24	2.07%	16.73	27.9%
875	$ 2.30	2.67%	$ 11.95	18.9%
1,625	$ 0.88	0.49%	(14.4)	-8.1%
3,250	$ 4.34	1.04%	(105.1)	-25.3%

[76] Exhibit ICA-2, p. 73; IHE Report, pp. 5-6. AE Quantification of IHE revenue requirement, WP H-3.1.1 (September 23, 2022).

The chart above reflects the impact of ICA's recommendation (1.6% residential increase and four tier rate design) compared to AE's three tier rate design with the IHE revenue requirement change. The divergence shown here is a function of AE's proposal to increase the unavoidable fixed customer charge by 150% ($10.00 to $25.00 per month), combined with AE's proposal to reduce the per kilowatt hour rates for each inclining tier of residential electric usage to the point that high users would experience a rate reduction. AE's current praiseworthy and progressive rate structure would become much less progressive, providing less reward to those customers who engage in energy efficiency and energy conservation. In reviewing rate structure impacts, we urge the Council to focus on inside city customers, who tend to use less electricity per household than outside city residents. Under the IHE's recommendation, inside city residential customers (who comprise the vast majority of AE customers) receive a base revenue increase of 16.4% which is 25% higher than IHE recommended 13.1% residential class base revenue increase.

When AE provided notice of its proposed rate increase, it did not inform its low usage customers that it was seeking rates that could impact residential customers that use less than the average amount of electricity with increases in the range of 27% - 80% on monthly bills. Such impacts would certainly constitute "rate shock" for those on the lower end of the usage spectrum.[77] Therefore, the ICA recommends that moderation and gradualism ultimately guide the final decision in this rate review proceeding.

[77] According to AE's Brian Murphy, a residential class revenue increase of 25.7% would constitute "rate shock." Murphy Rebuttal, Exhibit AE-9 at p. 13, l. 14-15.

The IHE does largely agree with the ICA's affordability concerns:

> The IHE finds that, if AE's proposed rate design is adopted, the billing increases applied to low usage sub-groups of the residential class will likely be large enough to cause rate shock. Accordingly, the principle of gradualism, as proposed by AE and addressed in Section IV above, should be applied to moderate both AE's proposed changes to the customer charge and the tier structure.[78]

However, the IHE ultimately defers to the discretion of the City Council to decide residential rate design issues:

> City Council may be better able to evaluate the competing goals of gradualism, preserving the conservation price signal, fairness, and financial stability in the context of specific competing tier proposals that incorporate updated numbers.[79]

Therefore, the ICA urges the City Council to adopt ICA's alternative rate design proposals as an amendment to the IHE recommendations. ICA expert witness Clarence Johnson offered a rate design solution in this rate review proceeding that would provide significant movement of the rate structure in the direction desired by AE, but would also balance the various policy goals, including gradualism, public acceptability, promoting energy efficiency, fairness, equity, and preventing rate shock on the lowest users.[80]

<u>Residential Customer Charge</u>

AE proposes to increase the residential monthly customer charge from $10.00 to $25.00, an excessive 150% percent proposed increase in this unavoidable charge. $25.00 is extraordinarily high compared to the fixed monthly charge of both bundled and unbundled electric utilities under the jurisdiction of the Texas PUC. The AE proposed residential fixed monthly charge would be

[78] IHE Report, p. 114.
[79] IHE Report, p. 126.
[80]

$13 higher than the highest regulated customer charge in Texas.[81] AE's desire to shift costs to the fixed customer charge is detrimental to low usage residential customers and blunts energy conservation incentives.

The difference between unbundled and bundled electric utilities in Texas is that the generation function is not part of the unbundled TDUs. But the generation function does not include customer costs and would not affect the customer charge. [82] The ERCOT average customer charge represents unbundled electric utilities, and the Non-ERCOT average represents bundled utilities like AE. The IOU average of customer charges are summarized below. Although the IHE did not accept the ERCOT average customer charge as comparable, the average of the four non-ERCOT utilities' customer charges is both comparable to AE and much lower than AE's proposed $25 customer charge. The $9.77 average for these comparable bundled investor owned Texas utilities demonstrates that AE's current $10 customer charge is reasonable.

Texas IOU Electric Utilities
Residential Fixed Monthly Charge

ERCOT Average	**$ 5.11**
Non-ERCOT Average	**$ 9.77**
Average all Texas IOU Electrics	**$ 7.44**

[81] Exhibit ICA-3, Schedule CJ-5.
[82] Although unbundled utilities operate call centers, it is possible this function is smaller than those operated by bundled utilities, because REPs may also operate a call center. However, total call center costs for bundled utilities are typically less than $1.00 per month.

Perhaps the best comparable for residential fixed rates are those currently charged by the other two other largest municipal electric utilities in Texas.[83] The residential customer charge of the three largest Texas municipal electric utilities is shown below[84]:

San Antonio City Public Service	**$ 9.10**
Austin Energy	**$ 10.00**
Lubbock Power & Light	**$ 8.07**

The ICA has calculated its own cost study for the residential customer charge, considering only those costs directly related to the number of customers ($6.11).[85] The calculation includes O&M expense for meters, services, meter reading, and customer accounting, and also encompasses the return, depreciation, and carrying charges associated with meter and service investment, minus credits for other customer-related revenues.[86] This method is known as the "Basic Customer Method." One prominent cost allocation manual concludes that the Basic Customer Method is "by far the most equitable solution" for the vast majority of electric utilities.[87]

Although the IHE casted doubt upon this method, the Basic Customer Method is also consistent with the historic Texas PUC practice for evaluating the customer charge level of bundled electric utilities.[88] Since AE's existing customer charge is $10.00, the current customer charge is more than compensatory for direct customer costs.[89]

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[83] Exhibit ICA-2, p. 13.
[84] Exhibit ICA-2, p. 13.
[85] Exhibit ICA-3, p. 60; Schedule CJ-6.
[86] The calculation also includes a portion of pensions and benefits (Account 926) associated with the O&M expense in the customer charge.
[87] "Electric Utility Cost Allocation for a New Era" at 145, Regulatory Assistance Project.
[88] *See* for example *Application of Houston Lighting & Power Company*, Docket No. 8425, Examiners' Report at 264, 16 P.U.C. Bull. 2199, 2488 (June 20, 1990).
[89] Exhibit ICA-3, p. 60.

There are numerous important policy reasons to ensure that the residential customer charge is not excessive. An excessive customer charge can distort appropriate price signals for residential customers. The dominant economic function of a customer charge is to ration access to the utility system. That objective conflicts with the policy basis for regulating monopolies and is counter to the concept of electricity as an essential service. With the exception of its role in rationing access to the system, the customer charge provides no meaningful price signal that is relevant to resource allocation.[90] Because the electric utility's cost structure is dominated by costs that vary with changes in demand and energy usage, the usage-sensitive rate is the primary source of meaningful price signals. A lower customer charge ensures a greater proportion of costs are recovered through a usage-sensitive price (i.e., kWh charges). That result is more consistent with energy conservation goals and provides pricing policies appropriate for consumption of finite natural resources Minimizing the customer charge provides the ratepayers with a greater ability to control their bill on the basis of usage. [91]

At a time when electric utilities spend millions of dollars on energy efficiency programs, maintaining the fixed monthly charge at a reasonable level is a relatively inexpensive action to incentivize energy conservation. If AE is allowed to increase the residential basic customer charge by 150%, while cumulatively *reducing* energy usage rates by 9%, there is likely to be a significant weakening of the price signal for energy conservation. This is contrary to AE's record and goals for conserving energy.[92]

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[90] Exhibit ICA-3, p. 62.
[91] Exhibit ICA-3, pp. 61-62.
[92] Exhibit ICA-3, p. 64.

Given that the current $10.00 customer charges exceed the Basic Customer Costs shown on Schedule CJ-6, maintaining the existing customer charge level is not unreasonable (particularly at relatively low residential base revenue increase percentages). However, the combined effect of the customer charge with the tier block energy charge rate structure is an additional consideration. A reasonable approach would seek to maintain the existing relationship between customer charge and energy charge revenues, and thus the ICA recommends limiting the customer charge increase based on the residential base revenue increase ultimately adopted. A maximum residential customer charge of no higher than $13.00 would be reasonable, which would be applicable only if AE's proposed residential revenue increase is adopted.[93] $13.00 should be viewed as a ceiling, not a floor, as suggested by the IHE Report.[94]

Residential Usage Tiers

The current residential rate structure consists of a $10 customer charge and five tiers (blocks) of energy charges. This structure is sometimes referred to as an inverted block rate, because energy charges for each tier increase as the customer's total kWh usage increases. The objective of this rate structure is to promote energy conservation. [95] AE proposes to reduce total revenues recovered from energy charges, and to further reduce the number of energy charge tiers from five to three. As a result of this restructuring, for inside city customers, low usage customers will pay a substantial increase in rates (34% - 52%), and higher usage customers will receive revenue reductions with a magnitude as high as -47%. AE's witness Mr. Murphy attempts to

[93] As noted previously, AE's proposal imposes a 26% base revenue increase on inside city customers.
[94] IHE Report, p. 114.
[95] Exhibit ICA-9. AE's public information website describes the residential 5 tier rate structure's energy conservation objective.

justify the changes as cost-based, but this is a serious misuse of the class cost of service studies.[96] Those studies estimate costs for *classes* of customers, not tiers within the class. The class cost of service study does not provide data regarding the contribution of various usage tiers to Residential class costs. ICA contends that the principle of gradualism should override flawed assertions of a cost basis. Therefore, ICA recommends tier rates with less extreme disparities in the rate change percentages.

The ICA's proposed rate design would be a more moderate change that includes four tiers. This is a compromise between AE's three tier proposal and the current five tier structure. Eliminating one tier should be sufficient to mitigate revenue volatility. Furthermore, the three tier structure is an obstacle to limiting absolute rate reductions in the upper usage tiers. As a matter of logic, reducing rates for upper tier customers is not a path for solving a class revenue deficiency. Furthermore, compared to AE's three tiers, the four tier structure addresses the energy conservation objective. Finally, ICA's proposed Tier 2 broadly covers 500 kWh – 1,300 kWh. Tier 1 and Tier 2 would encompass, on average, almost 90% of residential bills, which should increase revenue stability.[97]

The ICA urges the City Council to amend the IHE Report to adopt the ICA's four tier proposal.

<u>Current Rate Design Inappropriately Blamed for Utility Financial Performance</u>

AE's claim that its current rate structure is "unsustainable" is an exaggeration. Rate levels in any rate structure are not intended to remain the same over a lengthy period, and thus the

[96] ICA Ex. 3 at 74.
[97] ICA Ex. 3 at 72.

"unsustainable" characterization is inappropriate. The fact that Austin has a policy of periodic rate review as frequently as every three years should permit gradual corrections of the rate structure's billing units. Moreover, focusing on rate structure as the "problem" detracts from a critical review of rising costs and whether additional cost control is necessary.[98]

AE expresses concern that 2020 and 2021 required it to rely upon cash reserves. Yet both 2020 and 2021 are affected by extraordinary events—the COVID pandemic in both years, and Winter Storm Uri. The COVID pandemic caused a national economic shock which is unprecedented in history. Besides any potential impact on customers' power usage, AE responded to COVID by increasing funds for customer relief, additional discounts for the CAP program, ceasing disconnections, waiving late payment fees, and rates for the top two tiers in the residential rate structure. Winter Storm Uri resulted in lost revenues from 220,000 customers suffering more or less continuous outages for five consecutive days. In addition, AE subsequently gave credits to its customers and made other billing adjustments. AE has not quantified most of these impacts.[99] But these issues can affect the actual revenues and costs shown in the data that AE uses to tie its claim of financial stress to the residential rate design.[100]

AE's perspective on residential rate design is paradoxical. AE recognizes that the purpose of the five-tier structure is to promote reduced power usage and energy efficiency.[101] AE lauds its

[98] Exhibit ICA-3, pp. 65-66.
[99] However, the significant cost impacts of the pandemic were certainly acknowledged by AE in a memorandum to the City Council on August 2020. That historical memorandum is attached to the end of this document.
[100] Exhibit ICA-3, pp. 66-67.
[101] AE's web site advises customers: "Austin Energy has a five-tier rate structure that rewards customers who use less electricity with lower rates. With the five-tier rate structure, you can see how lowering your electric use can result in lower bills. You can lower your electric usage by modifying your energy use or by making energy-efficiency improvements to your home."
https://austinenergy.com/ae/rates/residential-rates/residential-electric-rates-and-line-items

energy efficiency programs and the city building codes. However, AE's objection to the five-tier rate structure is essentially that it has been too effective at promoting energy conservation. Furthermore, AE position ignores any potential long run reductions in utility cost which accompanies reduction in energy consumption.[102] Despite AE's recognition of the City's goal of energy conservation, the effort to re-structure the residential rates is likely to increase future electricity consumption.

Impacts on Low Income Customers

The IHE report agreed with the concerns raised by parties regarding how AE's proposed rate design would harm most low income (non-CAP) customers:

> The IHE notes that, according to the analyses of Mr. Robbins and SCPC/SUN, there is a positive correlation between income and energy consumption. If this is the case, then leaving aside the 7% of CAP customers, the reduction and flattening of tiers and increased customer charge would tend to increase the rates of lower and median income customers. The participants' contention that lower income customers consume less electricity raises questions regarding AE's opposite conclusion.[103]
>
> . . .
>
> The IHE is concerned that CAP does not encompass all or even most of AE's economically vulnerable customers. This concern extends to median customers as well. Furthermore, for whatever proportion of economically vulnerable customers are low usage, the ICA's analysis raises concerns for the IHE that their rates would rise sharply under AE's proposals.[104]
>
> . . .
>
> Outside the small percentage of customers served by the CAP program, bills will likely increase for lower usage customers, and decrease for higher usage customers. AE has not persuaded the IHE that the rates of these residential customers outside the CAP program will not increase significantly as a result of the rate redesign. As a result, the IHE is not

[102] The Regulatory Assistance Project Cost Allocation Manual at 157 states:" Energy efficiency costs are typically caused by the opportunity to reduce total costs to consumers. For most costs, revenue requirements would be lower if customers did less to require the utility to incur those costs."
[103] IHE Report, p. 112.
[104] IHE Report, p. 112.

persuaded that AE has adequately addressed the affordability of the new rates for economically vulnerable customers.[105]

While the ICA supports the utility's Customer Assistance Program (CAP), we do not believe that changing this program can solve the broad concerns about the unaffordability of AE's proposed rate design. While CAP customers may consume the same level or slightly more electricity than the average consumer, the preponderance of low income customers (who are not enrolled in that program) would be detrimentally impacted by a rate design that sharply increases rates for most low usage customers.

Clearly, CAP customers are not an accurate surrogate for all low income customers. For whatever reason, CAP customers use more energy than do most economically vulnerable households. The correlation between energy usage and income does seem to be universal. According to a government report on the federal Low Income Home Energy Assistance Program (LIHEAP):

> Low income households had average residential energy consumption of 73.8 MMBtus (about 13 percent less than all households) and average energy expenditures of $1,768 (about 15 percent less than all households). Their mean individual residential energy burden was 17.2 percent, over twice that for all households and over five times that for non-low income households.[106]

A similar trend appears to be true of LIHEAP participants as for AE's CAP participants.

> Average residential energy expenditures for LIHEAP recipient households were $1,933, about 9 percent higher than that for all low income households.[107]

The CAP program is a biased sample of low income households, which will tend to have higher average usage. But CAP encompasses only a fraction of low income households. Because low

[105] IHE Report, p. 113.
[106] U.S. Department of Health and Human Services, "Low Income Home Energy Data" (October 2018), p. 2.
[107] Id.

income customers tend to be apartment renters, they will be particularly harmed by increases at lower usage levels.

VII. Conclusion

The ICA urges the City Council to fully review the public comments received in the official record.[108] Comments from individuals who will be paying the rates and bills resulting from this rate review deserve to be heard. The ICA believes that the preponderance of these comments supports its contention that the rate design principle of "public acceptability" weighs in favor of its positions in this rate review.

In these times of rising inflation and cost of living concerns for residents of the City of Austin, the ICA recommends that its proposals be seriously considered, and that the final decision in this matter be mindful of avoiding unintended or dramatic rate impacts for *any* segment of the ratepaying customer base. The ICA believes that its proposals in this matter are just and reasonable, and carefully designed to minimize disparate rate changes among customers. The ICA respectfully requests that IHE's Report recommendations be amended as explain herein.

Respectfully submitted,

John B. Coffman

Date Filed: September 26, 2022

Independent Consumer Advocate

Attachment: AE Memorandum to Austin City Council (August 27, 2020)

[108] Exhibit ICA-5.

CERTIFICATE OF SERVICE

The forgoing filing has been served upon all of the email addresses contained in the official Service List for this proceeding as found on the website for the Office of the City Clerk's website on this 26th day of September, 2022.

Customer Driven. Community Focused.[SM]

M E M O R A N D U M

TO: Mayor and City Council

FROM: Jackie A. Sargent, General Manager, Austin Energy JAS

DATE: August 27, 2020

SUBJECT: Results of Rate Adequacy Review

The purpose of this memo is to inform City Council of the results of Austin Energy's Rate Adequacy Review as indicated at the Austin Energy Utility Oversight Committee meeting on August 19, 2020. This review is required to be completed a minimum of every five years under Austin Energy's Council-approved financial policies.

Executive Summary

Austin Energy has completed a Rate Adequacy Review using 2019 audited financial data as the test year. The review indicates that current base rate levels are adequate to meet current needs and bond covenant requirements, showing a potential revenue surplus of less than 1.5% of total revenues. There are, however, a number of significant changes occurring now and coming in the near future that will impact Austin Energy's finances. These changes include generating unit shutdowns at Decker, exiting the Fayette Power Project, the effects of the pandemic and associated economic impacts on our customers, and the potential impact on Austin Energy's accounts receivable. These factors cannot be adequately reflected in the 2019-based Rate Adequacy Review. Due to this uncertainty during challenging times, Austin Energy plans to maintain current base rates and delay any further rate review processes until the impacts of these events are better known and can be accounted for in a future cost-of-service study.

Rate Adequacy Review

Austin Energy Financial Policy No. 17, states that "a rate adequacy review shall be completed every five years, at a minimum, through performing a cost-of-service study." The policy also provides that Austin Energy's electric rates shall be designed to generate revenues sufficient to support operations and satisfy financial objectives. Additionally, Austin Energy is subject to a Master Bond Ordinance and state law, which require rates to be revised as necessary to ensure revenues sufficient to satisfy all bond requirements. Austin Energy reported to the Electric Utility Commission and City Council earlier this year that it was undertaking a cost-of-service study consistent with the policy.

Austin Energy conducted a cost-of-service study using the audited results of Fiscal Year 2019 as the test year (Test Year 2019). It examined in detail the utility's costs incurred to provide electric services to customers during Test Year 2019 and adjusted those costs as necessary to reflect normal operations. Austin Energy then compared those costs to the amount of revenues collected under current rates during the same time period adjusted for various factors including weather and customer count to "normalize" the results. If Austin Energy knows that a certain cost will change in the near future, it adjusts that cost element to the level it knows it will incur. These cost adjustments are referred to as "known and measurable" and ensure that the cost-of-service study best reflects the conditions when the rates become effective.

The cost-of-service study indicates that Austin Energy's current base rates produce an approximately $19 million revenue surplus, which is less than 1.5% of projected total retail revenues. Importantly, this projected revenue surplus is likely overstated as it is based on assumptions that do not consider impacts of the pandemic or anticipated changes to Austin Energy's generation portfolio. These ongoing and anticipated changes discussed below – which are not yet known and measurable – will impact revenues and cannot yet be adequately accounted for. Minimal changes to costs or revenues could easily eliminate the forecasted over-recovery, potentially putting Austin Energy's financial position at risk. Therefore, Austin Energy does not plan to change base rates at this time, which will avoid rate volatility for customers.

<u>Impact of Future Events</u>

The cost-of-service study is based on Test Year 2019 and does not account for the immediate or lasting effects of the COVID-19 pandemic on the economy and customer electricity usage. The most significant issues for Austin Energy are increasing accounts receivable and the change in how customers are using electricity during the pandemic. While total energy consumption is approximately in line with historic levels, there is a shift in energy consumption and demand among customer classes.

In the months since the pandemic began, residential customer electricity consumption has increased by 6%, commercial customer electricity consumption has decreased by 7%, and average secondary demand is down by 5%. However, Austin Energy does not know if the change in consumption and demand is a short-term event or is something that should be accounted for in future rates. There is also uncertainty with regard to the economic downturn and outstanding accounts receivable.

In addition, the *Austin Energy Resource, Generation, and Climate Protection Plan to 2030* approved by Council in March 2020 identifies specific actions that will result in adjustments to base rates. Decker Creek Power Station Steam Unit 1 will cease operations after the summer of 2020, Steam Unit 2 will cease after the summer of 2021, and Austin Energy will exit the Fayette Power Project (FPP) by year-end 2022. These actions will impact Austin Energy's cost-of-service study, both with regards to determination of the utility's revenue requirements and the allocation of those costs to various customer classes.

While these resource changes will occur prior to the end of the next five-year period, the financial impact of these events cannot be included in the known and measurable adjustments to the 2019 Test Year as sufficient milestones to make such adjustments have not yet been reached for all of these actions. A future cost-of-service study reflecting these impacts could show a revenue deficiency rather than a surplus. While this typically occurs to some extent in the ratemaking process, the magnitude of the current unknown and unmeasurable changes creates an additional degree of uncertainty that should be carefully considered. If rates are changed based on the current cost-of-service study results, they would likely need to be changed again in quick succession, causing rate volatility. To provide rate stability, Austin Energy will maintain existing base rates until the impact of these events can be considered in a future cost-of-service study.

Conclusion

Austin Energy has completed a Rate Adequacy Review on a five-year cycle through the performance of a cost-of-service study, as required by its financial policies, and has confirmed that current electric base rates comply with existing financial policies and bond covenants. Austin Energy has identified future events that are likely to have substantial effects on its cost of service with regards to both revenue requirements and cost allocation. The long-term impacts of the ongoing pandemic, retirement of Decker steam units, and exit of FPP will become known and measurable before the next five-year rate adequacy review and make a delay of rate changes for at least one year a prudent course of action.

No specific action is requested of Council at this time. Austin Energy will continue to monitor and report its financial performance and compliance with financial policies and bond covenants to the City Council. Additionally, Austin Energy is looking at ways to provide additional support for customers in Fiscal Year 2021. We continue to examine possible assistance measures and hope to bring forward a proposal for Council's consideration when we adjust pass-through rates. In the meantime, if you have any questions, please contact me.

Cc: Spencer Cronk, City Manager
Mark Dombroski, Interim Chief Financial Officer