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

IMPARTIAL HEARING EXAMINER'S FINAL RECOMMENDATION

September 9, 2022

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I. Introduction

This Final Recommendation is issued by the Impartial Hearing Examiner (IHE)[1] to provide the Austin City Council with recommendations regarding the City of Austin's (City) municipally owned electric utility, Austin Energy's (AE) 2022 Base Rate Filing Package (Base Rate Package or RFP). The procedural background of this Base Rate Review is addressed below.

As an initial matter, the IHE notes that AE did not request number-running associated with the issuance of this Final Recommendation.[2] As a result, while the IHE recognizes AE's legitimate goal of increased financial stability, the impact of the IHE's recommendations are unknown. This is, however, a reasonable approach to this Final Recommendation. The IHE discusses certain issues in the context of the policies City Council seeks to employ. For instance, the IHE makes recommendations regarding rate design, which is the manner by which the revenue requirement is collected from different customer classes. The rate design changes sought by AE are well-articulated and consistent with certain City and ratemaking policies and principles.

The IHE proposes, however, that AE explore either a different rate design or expanded targeted programs such as the Customer Assistance Program (CAP), which assists those AE customers who are vulnerable to rate shock due to increased rates. The IHE is aware that certain participants may argue that subsidization of one customer class or residential customer class by another is inconsistent with cost causation principles. AE is also concerned that subsidization creates financial instability. Ultimately, however, departing from certain traditional rate design principles on an issue this important is up to City Council to decide. The IHE provides recommendations, not conclusions, as to the City's direction for AE and its customers.

AE's Procedural Guidelines require the IHE to "[p]resent a recommendation on each issue identified and on other issues as deemed appropriate by the Impartial Hearing Examiner, and explain the rationale for arriving at that recommendation."[3] The IHE notes, however, that on a small number of issues, the parties provided no argument for the IHE to analyze. For uncontested issues, the IHE recommends adopting AE's position as set forth in the Base Rate Package. The

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[1] The Impartial Hearing Examiner is a neutral third party designated by the Austin City Council to review information from AE, community stakeholders, and customer groups participating in the Base Rate Review. A further description of the duties of the Impartial Hearings Examiner may be found at the City's webpages and AE's Procedural Guidelines.

[2] Number-running is a process used in traditional rate cases whereby the hearing examiner issues findings and conclusions based on their recommendations that contain specific numbers resulting from each recommendation. In other words, with a number-running process, the financial impact of each recommendation would be known at the time the hearing examiner's recommendations are issued.

[3] Procedural Guidelines at Section H.1.a.4.

IHE directs questions from the City Council on those uncontested issues to AE's counsel for further explanation.

AE and the Base Rate Review

AE is a non-profit, municipally-owned utility (MOU) with a stated mission to safely provide clean, reliable, affordable energy and excellent customer service. AE has served the community for over 125 years. AE seeks the legitimate goal of remaining financially strong. AE argues for the adoption of its proposals in this case to ensure that AE is able to fulfill its mission and continue to serve its customers and Austin's growth in the future.

Through this Base Rate Review, AE seeks to increase base rate revenue by $35.7 million. AE argues that its proposed revisions to its residential rate design will stabilize revenues and more equitably recover costs. AE's proposals are based on a Cost of Service (COS) Study that compares the base revenue requirement for the test year ending September 30, 2021, adjusted for known and measurable changes to the revenue generated by current base rates, which were previously set based on a 2014 test year. AE calculated the difference between these two balances to determine the proposed changes in AE's base rates. The COS Study confirmed that AE's base rates and base rate structures are not meeting the costs of serving its customers. In particular, AE contends that current residential base rates do not appropriately recover costs.

AE initially proposed an increase of its base rates by $48.2 million. After reviewing the cost of service and working with participants through the Base Rate Review process, AE made adjustments totaling $12.5 million.[4] As a result of these changes, AE reduced its request to $35.7 million. AE contends that the COS Study supports changes to the current base rate class structures. To address these findings and bring base rate financials back into balance, AE proposes to:

- Increase base rate revenues by $35.7 million to account for higher costs and growth;
- Update what AE considers to be an outdated residential base rate structure, to recover the costs to serve customers;
- Better recover fixed costs by relying less on energy sales; and
- Bring customers closer to what it costs to serve them, establishing more equitable charges as the community continues to grow.

[4] As discussed in the rebuttal testimonies of AE witnesses Rabon and Gonzalez, adjustments were made to nuclear decommissioning expense, interest on nuclear decommissioning, late payment fees, GFT, and Build America Bond (BAB) subsidy, reducing AE's request to $35.7 million. In addition, AE agreed to functionalize new service connection revenues to the customer function, rather than demand.

As a result, AE proposes to increase base rates for the first time since the 2012 Base Rate Review and only the second time since 1994.[5] The most recent Base Rate Review in 2016 resulted in a decrease of $42.5 million. Additionally, since AE's last Base Rate Review, Fiscal Year (FY) 2014 prices have increased 16.5% while rates have remained unchanged.[6] AE points out that, in the last 12 months alone, prices have increased 15%.[7]

AE's Concerns over Financial Stability

AE has articulated legitimate concerns over the financial stability of the utility. Through this rate base process, AE seeks to ensure AE's financial stability, allowing the utility to continue to deliver affordable, reliable electric service to its customers. AE contends that changes are needed for several reasons. First, AE has lost $90 million over the past two years in part due to the existing base rate structure and declining average consumption, in addition to rising costs in materials and equipment. Second, AE's current financial condition has resulted in less than 150 days of cash on hand, in violation of the City's financial policies. In response to AE's deteriorating financial condition, on June 28, 2022, Fitch Credit Ratings (Fitch) downgraded AE from 'AA' to 'AA-.' Fitch cited AE's elevated leverage, which has steadily increased during the past three years, and weaker operating cash flows primarily driven by lower base rate revenues that contributed to the utility's rising leverage. Significantly, AE points out that this downgrade assumes approval of the original $48.2 million base rate increase proposed by AE.

Revenue Requirement

As noted above, AE seeks to increase base rate revenues by $35.7 million to account for higher costs and growth. This is a reduction from the original $48.2 million base rate increase proposed by AE. Six participants took exception to AE's proposed revenue requirement. The participants' proposed adjustments to AE's revenue requirement ranged from $11 million to $41.7 million. AE expresses legitimate concerns that acceptance of the majority of the participants' adjustments to the revenue requirement would accelerate the deterioration of AE's financial position, decrease AE's operating cash flow, force AE to expend its cash and reserves, and increase its debt. AE argues that adoption of its base rate proposal is necessary to preserve AE's financial

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[5] The 2012 Base Rate Review resulted in a 6.4% increase. In the 2016 Base Rate Review, base rates were reduced by 6.7%.

[6] As measured monthly by the Consumer Price Index for All Urban Consumers: Fuels and Utilities from the St. Louis Federal Reserve. AE Ex. 3 at 5.

[7] AE Ex. 3 at 5.

health. As explained below, the IHE has largely agreed with AE's proposed revenue requirement, including known and measurable changes.

Cost Allocation

AE has also proposed a cost allocation structure, the details of which numerous participants disagreed with. AE correctly notes that some participants' proposals tend to shift cost allocation to classes that the participant does not represent. The IHE finds that the majority of AE's cost allocation proposals are reasonable and balanced. With few exceptions, the IHE recommends adoption of AE's cost allocation methods.

Rate Design

AE also seeks to revise the current residential base rate design in order to stabilize revenues and recover costs in what AE contends is a more equitable manner. Rate design is the one major issue where the IHE disagrees with AE. To be clear, AE has articulated and supported its rate design to move closer to cost for each of the proposed residential rate classes. And, if City Council prefers a rate design focused on cost causation, it would be appropriate to approve AE's proposed rate design.

As noted above, however, the IHE is concerned that vulnerable customers who do not qualify for AE's current CAP may experience rate shock, rendering the new rate design inconsistent with a known concern of affordability for certain Austin residents.

Through its rate design proposal, AE proposes to:

- Reduce the number of residential base rate tiers from five to three and flatten the tiers;
- Eliminate the base rate differential between inside- and outside-City of Austin customers;
- Eliminate the billing unit adjustment that currently benefits low load factor commercial customers; and
- Increase fixed charges for revenue stability, including increasing the residential customer charge from $10 to $25.

AE argues that these changes are necessitated by unprecedented customer growth, resulting in high infrastructure investment, combined with declining residential average energy sales. Despite the large increase in the number of customers, AE's load growth revenue has not kept pace.[8] Customer growth brings increased utility infrastructure investment and costs, but AE's base revenues have lagged. AE attributes the disparity in part to customer demographic trends,

[8] AE Ex. 1 at 8.

including the increasing share of multi-family housing—such as downtown condos and apartments—as compared to single-family homes. Overall, the City's housing mix has become increasingly dense and more energy efficient.

AE notes that declining average electric consumption has kept energy sales flat despite customer growth. AE contends that revenue growth is limited by a base rate design that relies too heavily on energy sales, particularly in the residential class. Currently, most residential customers are billed on a steep five tier structure with each tier priced progressively higher. AE notes that the first and second tiers are priced below cost and are subsidized by the fourth and fifth tiers that are above cost. AE contends that more than 40% of residential customers are subsidized by other residential customers.[9] AE argues there are not enough customers with consumption in the higher tiers to make up the revenue deficit from the under recovery in the lower tiers, as more customers use less energy, in part, due to the evolving housing stock. Additionally, certain commercial customers are paying more than the cost to serve them. As a result, AE proposes moving these rate classes closer to their cost of service. To limit rate impacts on customers, AE proposes gradualism in the form of moving the residential class to 50% of cost, rather than all at once.

Despite AE's gradualism proposal, which the IHE recommends, the IHE remains concerned that AE's new proposed rates may induce rate shock among residential customers who are not covered by CAP and yet are still economically vulnerable to rate increases. Although AE has presented well-reasoned arguments for its rate design, it proposes a fixed monthly customer charge increase from $10 to $25 per month—a 150% increase.

The City retained the Independent Consumer Advocate (ICA) to represent the interests of residential and small commercial electric consumers during the Base Rate Review. The ICA is concerned that AE's new rate design will shift cost responsibility from larger customer classes onto the residential and small business customer classes, and further shift that cost responsibility onto the smallest users within the residential class. Although the ICA raises other concerns, it argues that a fixed charge of $25.00 falls outside the range of residential fixed rates currently charged by the other two largest municipal electric utilities in Texas.[10] Based on its calculations, the ICA proposes a maximum residential customer charge of $13.00 in this case.[11] The IHE

[9] AE Ex. 3 at 12, *citing* AE Ex. 1 at 289.

[10] ICA Ex. 2 at 13. The IHE acknowledges, however, that Austin is a unique and rapidly growing city; the IHE addresses the relevance of these comparators in rate design, below.

[11] ICA Ex. 2 at 8.

provides these proposed customer charges to City Council to frame the discussion of this matter in Rate Design, below.

The ICA also estimates that customers that use less than the average amount of electricity could experience increased monthly bills in the range of 30-50%. There is evidence that increases above 25% could result in rate shock for those on the lower end of the usage spectrum.[12] The ICA developed the table below to illustrate the customer impacts of AE's proposed rate structure versus the ICA's proposals at different usage levels:[13]

	ICA- 1		**AE Filed**	
kWh	Increase	Percent	Increase	Percent
375	$ 0.59	1.56%	19.16	50.75%
625	$ 1.24	2.07%	19.15	31.90%
875	$ 2.30	2.67%	$ 15.34	17.81%
1,625	$ 0.88	0.49%	(8.20)	-4.59%
3,250	$ 4.34	1.04%	(92.63)	-22.2%

The ICA is not alone in expressing concerns over AE's proposed rate design. The ICA and other participants presented three basic recommendations: (1) leave the base rate design unchanged; (2) direct AE to develop a new proposal; or (3) make only minor changes to the current base rate design. The IHE does not propose a specific alternative rate design. This would be speculative without number-running. However, the IHE does recommend that AE either revisit its current rate design or consider a targeted assistance program like CAP, perhaps to be phased out over time, similar to the gradualist effect of AE's revenue distribution proposal, as discussed below. To be clear, the IHE understands that one way or another AE must recover its revenue requirement through its rates.

Value of Solar

Finally, AE also proposes a new approach to its Value of Solar (VoS) rate design that is intended to provide greater transparency and flexibility. AE's proposal is intended to fairly compensate customers for their onsite renewable energy production and adequately stimulate customer-sited solar adoption to help meet the City's Resource Generation and Climate Protection goals. AE contends that certain components historically used to calculate the VoS rate are based

[12] According to AE's Brian Murphy, a Residential class revenue increase of 25.7% would constitute "rate shock." Murphy Rebuttal, AE Ex. 9 at 13.

[13] ICA Ex. 2 at 73.

on assumptions that no longer align with AE's underlying costs. As a result, AE proposes a new methodology that is intended to more accurately allocate costs in accordance with standard utility ratemaking practices. As explained below, the IHE recommends approval of AE's VoS proposal.

Summary

The IHE recommends approval of a substantial portion of AE's revenue requirement, cost allocation methods, and VoS. Besides rate design, these are the basic elements that facilitate AE's duty to remain financially stable. AE presented well-reasoned arguments based on ratemaking principles, City and Financial policies, and its status as a non-profit MOU. Where the IHE departs from AE's Base Rate Package is rate design. Although certain participants challenge whether AE is correct on its cost concerns, AE is focused on assigning cost recovery to those customers who create the costs and moving from declining energy sales to better recover demand costs.

The IHE agrees with certain participants, particularly the ICA, who express concern over potential rate shock. AE's proposal to increase the customer charge from $10 to $25 may not result in rate shock for certain AE customers. However, the IHE is concerned that, for those customers who are vulnerable to rate shock and yet ineligible for CAP (as it is currently designed), AE's proposed increases may exacerbate a known affordability problem in Austin. As a result, the IHE recommends that AE's proposed rate design and targeted customer assistance programs like CAP be revisited by AE and the participants.

A. Procedural Background

On April 18, 2022, AE issued the 2022 Base Rate Package, which initiated a Base Rate Review process (Base Rate Review). On the same date, AE also issued Austin Energy's Letter to Participants regarding Cost of Service Model (AE Cost of Service Letter).

The Base Rate Review had three basic stages:

- After AE initiated the Base Rate Review, the participants sought and were admitted to the process.[14] Thereafter, the participants engaged in discovery, including some discovery disputes, and then settlement conferences with AE. The participants filed statements of position and testimony, including cross-rebuttal to each others

[14] The admitted participants were: 2WR – Holly Cooper and Vicki Dennis (2WR); Austin Regional Manufacturer's Association (ARMA); Coalition for Clean Affordable and Reliable Energy (CCARE); Data Foundry, LLC (Data Foundry); Homeowners for United Rate Fairness (HURF); The Independent Consumer Advocate (ICA); Victor Martinez; National Instruments (NI); NXP Semiconductor (NXP); Paul Robbins; Sierra Club and Public Citizen (SCPC); Solar and Storage Coalition (SSC); Solar United Neighbors (SUN); and Texas Industrial Energy Consumers (TIEC).

positions where there were differences among them. AE filed its rebuttal testimony and the parties generally prepared for the Final Conference.

- The next stage of the process involved preparation for and attendance of the Final Conference by AE and participants. The IHE noticed[15] and convened a Preliminary Conference on July 12, 2022. During the Preliminary Conference, the parties discussed final issues to facilitate a fair, impartial, and efficient Final Conference. The Final Conference began at 9 a.m. on July 13, 2022, and lasted through the end of the day on July 15, 2022.[16]
- Thereafter the parties submitted briefs to the IHE for consideration. At the Final Conference, the parties agreed to extend the briefing deadlines, such that AE filed its brief on August 9, 2022. The IHE drafted this Final Recommendation, which was issued on September 9, 2022.

The IHE notes that the Final Conference was not an evidentiary hearing in the normal sense, because the Administrative Procedure Act[17] did not apply, nor was the IHE authorized to swear in witnesses.[18]

II. Revenue Requirement

A. Approach

AE developed its revenue requirement using actual historical costs from FY 2021 with adjustments for known and measurable changes[19] in system costs, revenues, and customer composition. AE notes that its budget facilitates certain known and measurable adjustments to

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[15] The IHE issued notice of the Preliminary Conference and the Final Conference in Order No. 1 (April 28, 2022). Order No. 1 gave parties notice of the time, date, and location of the Preliminary (July 12, 2022) and Final Conference (July 13-15, 2022), (Austin Energy Headquarters, 1st Floor, Shudde Fath Conference Room, 4815 Mueller Blvd, Austin, Texas 78723).

[16] Although 14 participants were admitted in this Base Rate Review, only 10 filed position statements and nine participated in the Final Conference. In addition to AE, the Final Conference was attended by representatives and witnesses on behalf of: 2WR, Data Foundry, HURF, the ICA, NXP, Paul Robbins, SCPC, SSC, and TIEC.

[17] Tex. Gov't Code ch. 2001.

[18] Procedural Guidelines Section G.1.a. and G.2.f.

[19] The Texas Supreme Court has explained that "future rates are made on the basis of past costs" and "[c]hanges occurring after the test period, if known, may be taken into consideration . . . to make the test year data as representative as possible of the cost situation that is apt to prevail in the future." *Suburban Util. Corp v. Public Util. Comm'n*, 652 S.W.2d 358, 366 (Tex. 1983). AE acknowledges it must show the adjustment (1) is quantifiable, and (2) reflects investment or expense that either is used and useful in the delivery of electric service or will become so prior to the effective date of the supporting rate structure. AE Rate Filing Package at 27, n.11; *see also Application of Oncor Electric Delivery Company, LLC for Rate Case Expenses Pertaining to PUC Docket No. 35717*, PUC Docket No. 36530, Order at 3 (Sept. 21, 2009).

historical accounting records, such as personnel costs, equipment, or supply cost increases. In other instances, AE annualized certain costs incurred for part of the historical year to reflect 12 months of operations.

Participants proposed a number of reductions to AE's revenue requirement. AE argues that while some participants challenged AE's proposed known and measurable adjustments, they did not challenge the reasonableness of the actual test year expenses. AE posits that each post-test year adjustment is known and quantifiable and reflects investment or expense that is used and useful in the delivery of electric service or will become so prior to the effective date of the supporting base rate structure. Accordingly, AE requests that the participants' recommended disallowances be rejected.

As explained below, the IHE largely agrees with AE on challenges to its revenue requirement request, in many instances because AE's proposal is designed to best conform to its financial policies or determinations by City Council. The IHE, however, raises policy questions or disagrees with AE on certain issues, such as the General Fund Transfer and the effect of Winter Storm Uri on present sales and billing determinants. The IHE addresses the contested issues identified by the parties below. Uncontested issues are not addressed. The IHE defers to AE's positions and evidence, including the Base Rate Package, on uncontested issues.

B. Cash Flow Methodology

AE uses the cash flow method to develop the return component of its revenue requirement.[20] Under the cash flow method, the total revenue requirement includes the gross annual cash AE needs to operate, maintain, and capitalize the utility, including the cost of operations and maintenance, transfers and shared services, cash funded capital, funding for decommissioning obligations, replenishment of reserve funds (if needed), annual debt service payments on bonds, satisfying debt covenants, and financial policies. AE notes that not-for-profit public power utilities like AE frequently use the cash flow method to develop the return component.

NXP Semiconductors, Inc. (NXP) argues that AE's inclusion of depreciation and amortization in the development of the return under the cash flow approach is in error.[21] In response, AE notes that NXP's witness, Chuck Loy, acknowledged that the Public Utility

[20] AE Ex. 1 at 28.
[21] NXP Ex. 1 at 51-54.

Commission of Texas' (PUC or Commission) Transmission Cost of Service (TCOS) Rate Filing Package for Non-Investor Owned Utilities (TCOS Non-IOU RFP) contemplates use of the cash flow approach and depreciation expense.[22] AE argues that, because depreciation is a part of the expenses included by the utility, the cash flow approach must recognize this non-cash expense when developing the cash flow return.[23]

It has been noted that the Brownsville Public Utilities Board (BPUB) filed a TCOS RFP at the Commission using the cash flow approach that did not include depreciation. AE points out that this is unusual and BPUB's fallout rate of return was incomparable with other non-investor owned utilities. AE argues that NXP's approach places both the return of and the return on utility plant investment into the return amount. This makes the resulting return dissimilar from the returns of other utilities, which obtain return of investment through depreciation and return on investment through the calculated return.

AE points out that removing depreciation and amortization from the development of the revenue requirement would increase the implied return on rate base. It would not, however, change the overall revenue requirement because removal of depreciation and amortization amounts from the analysis increases cash needs by the same amount.[24] AE notes that this differs from the utility basis relied on by for-profit investor-owned utilities (IOUs) to develop a revenue requirement, where the return on rate base is relevant.

AE did not use the utility basis in developing the revenue requirement because it does not seek profits. AE is a not-for-profit entity; the application of the utility basis would be complicated by difficulties in determining an appropriate return. The cash flow approach better aligns with the key considerations for a MOU, such as AE. The IHE agrees with AE and recommends use of the cash flow methodology with inclusion of depreciation and amortization. AE's approach is consistent with non-investor owned utility TCOS rate filings at the Commission, including – as noted by AE - AE's last full TCOS case.

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[22] *See* Instructions for Transmission Cost of Service Rate Filing Package for Non-Investor Owned Transmission Service Providers in the Electric Reliability Council of Texas (Non-IOU TCOS RFP); specifically Schedule C-3 (cash flow method) and Schedule E-1 (depreciation expense): https://www.puc.texas.gov/industry/electric/forms/rfp/Non_IOU_TCOS_Instr.pdf.
[23] AE Ex. 6 at 21.
[24] AE Ex. 6 at 22.

1. Operations and Maintenance Expenses

a. 311 Call Center

The 311 Call Center is a 24 hours per day, 365 days per year contact center to connect City residents and customers to city services and information.[25] The AE Utility Contact Center (AE Call Center), which performs the functions of a call center for AE customers, operates limited hours: Monday through Friday from 7 a.m. to 9 p.m. and Saturdays from 9 a.m. to 1 p.m.[26] The 311 Call Center acts as call support back-up for the AE Call Center during storms and emergency events and when the AE Call Center is closed.[27] Costs associated with the 311 Call Center are allocated to city departments, including AE, based on the total duration of all calls in minutes, consistent with cost causation.[28]

AE seeks test-year operations and maintenance (O&M) expenses for the staffing of the AE Call Center, back-office personnel, and the 311 Call Center, which totals $8,372,198.[29] AE notes that City Council approved the execution of a new five-year staffing contract for the AE Call Center in February 2022, which has an expected annual cost of $13,754,724. As a result, AE seeks a known and measurable adjustment to the test year in the amount of $5,382,525 (i.e., $8,372,198 + $5,382,525 = $13,754,724).[30]

The ICA argues for a reduction in AE's request for the AE Call Center because the basis for AE's known and measurable adjustment is only an estimate of the annual expense under the new contract and because the full staffing level outlined in the contract document has not been met at this point.[31] The ICA notes that the annual cost of the contract is $5,382,525 greater than the actual call center staffing expense of $8,372,198 in Fiscal Year 2021, or 64% over the actual Fiscal Year 2021 expense.[32]

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[25] AE Ex. 5 at 6.
[26] AE Ex. 5 at 6.
[27] AE Ex. 5 at 6. For instance, on weeknights, the 311 Call Center functions as the AE outage call handler for ten hours of each 24-hour period, from 9 p.m. to 7 a.m. On weekends and holidays, the 311 Call Center handles outage calls from 1 p.m. on Saturday until the AE Utility Contact Center opens at 7 a.m. on Monday.
[28] AE Ex. 5 at 7.
[29] AE Ex. 5 at 4.
[30] AE Ex. 5 at 5.
[31] ICA Ex. 2 at 11-12.
[32] ICA Ex. 2 at 11.

First, the ICA argues that the AE Call Center expense overage is not a known and measurable adjustment because it must be known and measurable "with reasonable certainty."[33] The ICA points out that AE's discovery responses state "[t]he quantities listed . . . are *estimates* for year one of the contract. The City reserves the right to purchase more or less of these quantities as may be required during the contract term."[34] AE responds that the new five-year staffing contract was executed in February 2022, and is thus a known agreement, whether or not it contains an estimated quantity.

In a second and related argument, the ICA proposes a reduction to AE's known and measurable adjustment for the AE Call Center by $2,880,623, because as of April 2022, AE had filled only 185 of the 234 positions for the AE Call Center.[35] ICA notes that despite further discovery, and cross examination at the conference, AE could not provide any actual updates to its staffing at the time of the conference.[36] As a result, the ICA argues that, in calculating the revenue requirement, allowable cost under the new staffing contract should be reduced by 20.9%, or $2,880,623.[37] AE responds that it has continued to fill positions and "anticipates meeting the full staffing level outlined in the contract by 2023, which would align with the timing of the implementation of the base rates approved from this Base Rate Review."[38] Therefore, the amounts in the contract are quantifiable and reflect expenses that would be incurred prior to the effective date of the supporting base rate structure.

The IHE agrees with AE and does not recommend the reduction that the ICA seeks. It is the nature of staffing contracts that it takes time to hire all of the employees contemplated by the contract. It would be inappropriate to reduce the amount sought by AE while it is still in the process of staffing under the contract, which staffing levels are known and measurable, because AE made clear with adequate certainty that it intends to meet full staffing levels.

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[33] ICA Brief at 6 (citing Texas PUC Order on Rehearing, <u>Southwestern Public Service Co.</u> Docket No. 43695 (2016), FOF No. 26B).
[34] ICA Ex. 1 at 11-12.
[35] AE Ex. 5 at 10-17. Exhibit ICA-2, p. 11-12. The attachment to AE's response to ICA RFI 2-9 includes 234 employees in the estimate of the annual cost of the new contract. Based on AE's response to ICA RFI 4-5, the actual number of employees as of end of April 2022 was 49 fewer than the number of employees assumed by AE in calculating the estimated annual cost of the new staffing contract.
[36] AE's Response to ICA 4-5 and 8-1.
[37] ICA Ex. 2 at Schedule DJE-1.
[38] AE Ex. 5 at 6.

Participants Holly Cooper and Vicki Dennis (2WR) argue that AE failed to establish the reasonableness of the 311 Call Center's costs or its surcharge to AE.[39] However, AE's witness Mr. Galvan testified that it is reasonable for AE to be responsible for the cost of after hour and weekend calls.[40] 2WR also asserts that the allocation of 311 Call Center costs are unreasonable because "not all customers utilize this service, many don't."[41] The IHE rejects 2WR's argument. Calls centers are designed to be available to all customers and accessed on an as-needed basis for situations that usually do not apply to all customers at all times. In this regard the call center benefits all AE customers. The IHE also agrees with AE that, in providing this critical service, it is sound public policy to recover the costs from all AE customers. AE notes that no 311 Call Center costs unrelated to AE customers are being recovered in AE's base rates.

2WR also argues that the 311 Call Center cost is unreasonable because AE has invested in digital meters, and thus there is no need for a call center for AE to learn of outages.[42] However, as AE points out in rebuttal testimony, the 311 Call Center provides services beyond the benefits of digital meters.[43] AE notes that customers can call to report an outage and ask questions about an outage at a residence, a downed wire on a street, to request additional information on restoration efforts, and inquire about other matters or issues that cannot be addressed by information from a digital meter.[44]

The IHE agrees with AE on this matter. Digital meters only provide certain information that is less than the information that can and should be available through access to a call center serving AE customers. The IHE also agrees with AE that after-hours surcharge amounts should not be excluded from the annual operating costs of the 311 Call Center allocated to AE. The consistent provision of electric energy is a fundamental need of any electric utility customer 24-hours per day, seven days per week.[45] The 311 Call Center supports this need.

The IHE recommends the City Council approve the full amount of AE's requested expenses (test-year expenses and post-test year adjustments) associated with the 311 Call Center and AE Call Center.

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[39] 2WR Brief at 8.
[40] Tr. (July 15) at 6:7-33 (AE Rebuttal).
[41] 2WR Brief at 8.
[42] 2WR Brief at 5.
[43] AE Ex. 5 at 7.
[44] AE Ex. 5 at 7.
[45] 2WR Ex. 1 at 5-6.

b. Uncollectible Expense

AE seeks uncollectible expense in the amount of $5,994,177, after a known and measurable adjustment to uncollectible expense of ($7,837,013).[46] This downward adjustment is associated with a non-recurring event related to the adjustment made to Other Revenues—Facilities Rental revenue. The ICA argues that the test-year 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 ICA attributes this to Winter Storm Uri and the COVID pandemic.[47] As a result of unusual conditions during the test year, the ICA recommends using AE's three-year average uncollectible amount, FY 2018 – FY 2020, as the appropriate level of uncollectible expense.[48] The ICA argues this period is recent and excludes the conditions that affected FY 2021. The three-year average uncollectible amount is $4.574 million.[49]

The ICA notes that, even with AE's reduction of the test year expense for a known and measurable adjustment (pertaining to a single non-residential customer), the requested cost of service amount is $5.99 million, which is $1.4 million higher than the average for the prior three years. As a result, the ICA recommends a reduction in the uncollectible expense portion of the revenue requirement by $1.4 million.[50]

AE responds that there is no indication that a three-year average is more appropriate than actual test year data.[51] AE points out that the impact of the pandemic is ongoing and neither AE nor any other participant can predict the end of the pandemic or future events.[52]

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 it's end is unknown. To a certain extent, the pandemic's effects are long-lasting and can be viewed as the new normal. Regarding

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[46] AE Ex. 1 at 38, 41, 256.

[47] ICA Ex. 3 at 15. The ICA argues that the pandemic caused severe dislocation among AE customers, including loss of employment, inability to work from employers' offices, closure of schools and universities, an AE moratorium on disconnections in March 2020, including the reconnection of recently disconnected customers, which extended into summer 2021. The ICA notes that disconnections were suspended again after Winter Storm Uri.

[48] ICA Ex. 3 at 16.

[49] Calculation is based on data provided in response to ICA Request 4-8.

[50] ICA Ex. 3 at 15-16.

[51] AE Ex. 4 at 8.

[52] AE Ex. 4 at 8.

the impact of Winter Storm URI, while the IHE acknowledges its severity and magnitude, the evidence does not link the storm to uncollectible expense. AE made a separate adjustment to late payment fees as a result of policies that temporarily eliminated late payments fees as a result of Winter Storm Uri.[53] And the fact that disconnections were suspended for a period after Winter Storm Uri, as pointed out by the ICA, does not establish that the storm contributed abnormally to uncollectible expense in FY 2021; rather, suspension of disconnections would suggest that any uncollectible expenses were delayed or avoided.

Accordingly, the IHE recommends that AE's uncollectible expense be set at $5,994,177.

c. Heavy Equipment Lease

AE made a known and measurable adjustment of $7,421,233 to the heavy equipment lease test-year expense amount, based on a three-year average of lease payments on existing equipment.[54] The ICA proposes a downward adjustment of ($7,344,072) based on FY 2022 costs.[55] The ICA argues that AE's actual expense for heavy equipment in FY 2021 was $5,338,897 – the only portion of this expense which is known and measurable.[56] The ICA notes that AE adjusted the heavy equipment lease expense to reflect the *forecasted* three-year average expense for Fiscal Years 2023 – 2025. The ICA points out that the forecasted fiscal period extends four years beyond the test year, and the time period used for expenses must match the time period used for revenues; a known and measurable adjustment which is based on forecasts beyond the test year will violate this matching principle.[57] The ICA notes that the effect of this adjustment is to increase test-year distribution O&M expense by $7,407,652.[58]

ICA argues that AE failed to demonstrate that the three-year average is known and measurable, because AE acknowledged that the projected lease costs for FY 2023-2025 are not contractual obligations.[59] The ICA argues that the major increases in the forecasted heavy equipment lease expense are not expected to start until May 2023, which are too remote from the

[53] AE Ex. 4 at 7.
[54] AE Ex. 1 at 39, 41.
[55] ICA Ex. 2 at 10.
[56] AE response to ICA Request 2-8, Attachment Page 2.
[57] ICA Brief at 8 (citing *Application of Southwestern Public Service Co*., Docket No. 43695 (2016) Order on Rehearing, FOF No. 24A).
[58] AE Work Paper D-1.2.12. The ICA notes that in Fiscal Year 2022, the budgeted heavy equipment lease expense charged to distribution O&M is $5,338,896.96. This is $7,344,072 less than the projected three-year average of $12,682,969 for Fiscal Years 2023 – 2025. AE response to ICA Request 2-8, Attachment Page 2.
[59] AE response to ICA Request 4-4.

Fiscal Year 2021 test year and too uncertain to be considered "known and measurable."[60] Accordingly, the AE revenue requirement should be reduced by ($7,344,072).[61]

AE responds that the Altec heavy equipment lease has been the historical method by which AE acquires heavy equipment since 2007. AE points out that the current agreement is a fully executed lease contract. The contract provides for annual extensions as set out in the contract. The City Council approves operating budgets on an annual basis that include the extensions. It has done so since the execution of the first lease agreement in 2007. Although City Council authorizes the extensions annually, the financial obligations are set out in the original binding contract. AE notes that the current extension is awaiting City Council approval in September 2022.[62]

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.

The IHE recommend that AE's heavy equipment lease expense be set at $7,421,233.

d. Non-Nuclear Decommissioning

City of Austin Financial Policy No. 21 requires AE to set aside funds to pay for the eventual retirement and decommissioning of the utility's non-nuclear generation fleet.[63] The non-nuclear fleet comprises the Decker Creek Power Station, the Fayette Power Plant (FPP), the Nacogdoches Power Plant (Nacogdoches), and the Sand Hill Energy Center. Funds must start accumulating no later than four years prior to commencement of decommissioning activities. AE notes that, 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, in the 2016 Base Rate Review, AE initially proposed to add $19.4 million of additional revenue to cover future decommissioning expenses. The cost estimates were developed and reported by NewGen Strategies and Solutions in a July 2015 study that examined the entirety of AE's reserved funds and policies (NewGen Study). Ultimately, the 2016 case settled with AE agreeing to include $8 million in base rates for non-

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60 ICA Ex. 2 at 9-10.
61 ICA Ex. 2, Schedule DJE-1.
62 AE Ex. 3 at 14-15.
63 AE Ex. 1 at 371.

nuclear decommissioning.[64] AE has reserved $8 million each year since that time.[65] Despite inflation and the acquisition of the Nacogdoches facility since the last case, AE proposes no change to the $8 million funding level approved six years ago.

ICA recommends an adjustment of $6 million, which would reduce the amount of non-nuclear decommissioning to be recovered in base rates to $2 million.[66] ICA correctly notes that AE has the burden of proving the reasonableness of the amount of non-nuclear decommissioning expense. In reaching its conclusions, ICA relied on the only decommissioning study presented, the 2015 NewGen Study. ICA points out that AE has not presented a new study nor any additional analysis to support its position.

ICA argues that $8 million significantly exceeds the appropriate prospective annual allowance for non-nuclear decommissioning. ICA bases this conclusion on the estimated cost of decommissioning documented in the NewGen Study and the amount AE has already recovered in rates for non-nuclear decommissioning.[67] ICA summarized the estimated costs of decommissioning each of the non-nuclear generation plants.[68] ICA's witness Effron calculated a mid-point estimate, based on the average of the "Low Range Estimates" and "High Range Estimates" shown in the NewGen Study, resulting in a total of $62.8 million for three generation plants in the study, which ICA argues is an unbiased estimate and an appropriate starting point for determining the appropriate annual contribution to the decommissioning reserve.[69]

ICA argues that the rates established in the 2016 Rate Review will have been in effect for six years by the time 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. ICA estimates that, by that that time, approximately only $14.8 million of the estimated total decommissioning costs of $62.8 million will remain to be recovered.[70] As a result, Mr. Effron recommends that $14.8 million be recovered over the remaining lives of the non-nuclear generation plants. Based on that remainder, Mr. Effron calculated that the average remaining life, weighted by the estimated decommissioning cost of the

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[64] AE Ex. 6 at 14.
[65] AE Ex. 6 at 14.
[66] ICA Ex. 2 at 5-7.
[67] ICA Ex. 2 at 5-7.
[68] ICA Ex. 2, Schedule DJE-2.
[69] ICA Ex. 2 at 5.
[70] ICA Ex. 2, Schedule DJE-2.

plants, is approximately 9.4 years. According to Mr. Effron, this would result in an annual non-nuclear decommissioning expense of $1,570,000. To be conservative, Mr. Effron 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, instead of the $8 million AE has requested.

AE argues that ICA failed to establish that the reduction is reasonable and the IHE agrees. First, AE notes that ICA was unaware how many generating units are scheduled for decommissioning; Mr. Effron was unaware of the existence of the Nacogdoches plant or the need to decommission it.[71] In fact, AE is now planning for the decommissioning of Nacogdoches, which was not included in the NewGen Study because AE did not own the facility at the time.[72] The IHE finds that this fact alone undermines ICA's calculations.

Second, AE notes that Mr. Effron appears to have conducted a limited investigation to determine whether his recommendation was reasonable.[73] In the 2016 Base Rate Review, the ICA recommended a total decommissioning expense level of $9.89 million.[74] Mr. Effron was unaware of this fact. AE also notes that Mr. Effron's analysis starts by calculating a mid-point estimate of the cost of decommissioning each generation unit based on the low range and high range estimates from the NewGen Study.[75] AE correctly points out that this fails to recognize that the cost to decommission a generation unit has increased since 2015 due to inflation and that decommissioning costs were estimated.[76] The actual cost of decommissioning may be significantly higher. For instance, AE's decommissioning of the Holly Power Plant lasted longer, was more extensive, and more expensive than originally estimated.[77] The original decommissioning estimate for the Holly Power Plant was $19 million, but the total actual cost was approximately $32 million.[78] The IHE finds that these facts undermine confidence in Mr. Effron's analysis and calculations.

ICA, however, raises a good point that AE did not update the NewGen Study. Although the IHE prefers that AE had updated the study, this does not rise to the level of rendering AE's

[71] Tr. (July 14) at 66:30-44 (Effron Cr.).
[72] AE Ex. 6 at 14.
[73] Tr. (July 14) at 65:39-45–66:1-14 (Effron Cr.).
[74] The ICA in 2016 is the same individual acting as the ICA in the current case.
[75] ICA Ex. 2 at 4-7.
[76] AE Ex. 6 at 14.
[77] AE Ex. 6 at 14-15.
[78] AE Ex. 6 at 14-15.

decommissioning request unreasonable. As noted above, the $8 million in estimated costs is still backed by the study, there is evidence in the record that the original estimates of decommissioning each plant have been and will likely continue to be significantly exceeded by actual costs, and in the 2016 rate case, the ICA recommended a total decommissioning expense level of $9.89 million.[79]

Finally, AE provided testimony explaining the nature of decommissioning expenses, which helps establish the reasonableness of retaining the rolling expense at $8 million. AE explains that, because the actual future cost to decommission AE's non-nuclear plants is unknown, decommissioning funding is an estimate.[80] If the $8 million annual figure proves to be too low, AE will need additional funds, such as issuing debt, to pay for the decommissioning obligations for generation units at the time of retirement. AE notes that this would likely involve funding by future customers that may never have benefited from the generation units when they were in service, which presents an intergenerational equity issue.[81] On the other hand, AE explains that if the $8 million estimate proves too high, AE can holdover funds to decommission the next non-nuclear unit to be decommissioned. If, in the future after retiring a unit, it appears that the $8 million per year is going to over-fund this obligation long-term, AE notes that the amount can be reduced. AE contends, however, that there is no indication that $8 million annually is going to over-fund the obligation. Inflation and AE's past experience with the Holly Power Plant would suggest the $8 million figure will prove insufficient to fully fund this obligation.[82]

The IHE recommends approval of AE's $8 million estimate for decommissioning expense. The estimate is backed by the NewGen Report and AE has an obligation to ensure these funds are secured under Financial Policy No. 21 for the eventual retirement and decommissioning of the utility's non-nuclear generation fleet.[83] The IHE also agrees that seeking to fully fund the non-nuclear decommissioning reserve is the best way to mitigate intergenerational equity concerns.[84]

e. Winter Storm Uri and COVID-19 Expenses

In February 2021, Winter Storm Uri struck most of Texas, including Austin. This was an extreme winter storm and rare in terms of intensity and duration. According to the ICA, over

[79] AE Ex. 6 at 14-15.
[80] AE Ex. 6 at 14.
[81] AE Ex. 6 at 16.
[82] AE Brief at 12.
[83] AE Ex. 1 at 371.
[84] AE Ex. 6 at 16.

220,000 customers in Austin experienced electric outages for 4 to 5 days.[85] The ICA, Texas Industrial Energy Consumers (TIEC), and 2WR all propose adjustments to AE's revenue requirement for storm costs related to Winter Storm Uri.[86] AE acknowledges that Winter Storm Uri was an exceptional event, but argues that storm costs associated with it were not exceptional or abnormal. AE points out that it experiences storm outages every year and substantially all of the resources that were used in the Winter Storm Uri response are used in the normal course of a year, including regular storm response.[87] Although outages associated with Winter Storm Uri lasted over an extended period of time, it was due primarily to Electric Reliability of Council of Texas (ERCOT)-directed load shed.

AE estimated $6.8 million for labor and benefits, overtime pay, and contract labor for Winter Storm Uri restoration.[88] The ICA contends that Winter Storm Uri should be considered abnormal for ratemaking purposes and AE's cost of service should be adjusted for Winter Storm Uri.[89] The ICA recommends amortizing the $6.8 million in Winter Storm Uri expense over five years and to include only one-fifth of that amount, or $1.36 million, in the test year revenue requirement.[90] The ICA argues that regulatory authorities frequently amortize costs caused by extraordinary storms and hurricanes to represent the interval between events of similar magnitude. Because some normal level of storm restoration costs is likely to occur in the future, the ICA recommends a five-year period as a reasonable balance. As a result, the ICA proposes only $1.36 million of the $6.8 million test year amount be included in cost of service. The difference of $5.44 million, is a reduction to cost of service.[91]

AE notes that the ICA did not contest the reasonableness of the overall test year costs.[92] Of the $6.8 million in expenses the ICA proposes to disallow, $4.3 million is related to labor and benefits, $1.2 million is related to overtime, and $1.3 million is related to contract labor. AE

[85] ICA Ex. 2 at 14.
[86] TIEC addresses Winter Storm Uri and proposed changes to test year billing determinants, which is addressed in the rebuttal testimony of AE witness Murphy and in Section II.C below. 2WR makes a recommendation concerning late payment fees associated with Winter Storm Uri, which is addressed in the rebuttal testimony of AE witness Gonzalez and in Section II.B.8.a.
[87] AE Ex. 2 at 5.
[88] Response to ICA Request 4-12. AE recorded these expenses in March 2021.
[89] ICA Ex. 2 at 14.
[90] ICA Ex. 3 at 14-15.
[91] ICA Ex. 2 at 15.
[92] AE Ex. 2 at 8.

explains that it regularly incurs labor, overtime, and contractual labor costs during the course of the year, including during periods of storm restoration.[93]

With respect to the $4.3 million in labor and benefits, AE states that these "were regular wages and benefits paid to AE employees who would have been paid during the period that Winter Storm Uri occurred regardless of whether the storm had happened or not."[94] Although the ICA points out that utilities frequently include regular labor and benefit expense when they segregate extraordinary storm expense,[95] the IHE agrees with AE that the regular wages and benefits expense would have been incurred regardless of the storm. Those expenses should not be amortized over 5 years as recommended by the ICA.

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.[96] The ICA notes that, if the 2017-2020 fiscal years are *averaged*, the 2021 annual overtime and contract labor exceeds the historical average by $1.5 and $1.55 million, respectively.[97] These amounts are higher than the reported Uri restoration overtime and outside labor expense. However, as noted below, a direct comparison of FY 2020 and FY 2021 costs for both types of expenses yields mixed results.

Regarding overtime, AE responds that the $1.2 million in overtime costs are identical to those AE regularly incurs during normal operations and annual storm outages. AE stated that overtime costs incurred during the test year are consistent with historical overtime over the last five years, especially in light of yearly wage increases and rising job vacancies.[98]

Regarding contractual labor costs, AE states that the $1.3 million in costs during Winter Storm Uri restoration was attributable to vegetation management companies for their services. AE notes that it paid less to these contractors in total during the test year than in the previous year and not abnormally more than the two prior years.[99] The IHE confirms that total contractual labor costs

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[93] AE Ex. 2 at 6-8.
[94] AE Ex. 2 at 6.
[95] Tr. (July 14) page 88-89.
[96] Tr. (July 14) page 89-90.
[97] 2017-2020 annual averages for overtime and outside labor are $9.3 and $14.3 million respectively, compared to 2021 overtime and outside labor expense of $10.8 and 15.6 million, based upon the tables on page 7 of Maenius Rebuttal.
[98] AE Ex. 2 at 7.
[99] AE Ex. 2 at 7.

for FY 2020 were $17.6 million and for FY 2021 they were $15.6 million.[100] Finally, AE argues that the ICA provided no proof that restoration costs incurred during the test year are atypical and instead focuses on the fact that Winter Storm Uri was an unusual storm.

The IHE acknowledges that Winter Storm Uri was an unusual, dangerous, and deadly storm. The outages associated with that storm had significant impacts on a number energy providers and citizens throughout the state. However, the evidence shows that AE's expenses associated with the storm were not unusual in terms of its use of resources devoted to these types of events. AE explained that the storm-related outages did not result from physical damage to the system. The outages were related to a lack of generation and ERCOT-directed load shed. 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.[101] 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.

f. Rate Case Expense

AE proposes to collect $1,791,000 in rate case expenses associated with this proceeding over a three-year period (i.e. $597,015 x 3 years = $1,791,000).[102] AE notes that no participant objected to the reasonableness of the requested amount. The ICA and 2WR, however, propose a five-year amortization period for the recovery of rate case expenses.[103] Specifically, the ICA argues the last AE rate case was six years ago, so a recovery period of at least five years would be more appropriate than three. The ICA calculates that 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.[104]

AE responds that under the City of Austin's Financial Policy No. 17 "[a] rate adequacy review shall be completed every five years, at a minimum, through performing a cost of service study."[105] AE argues that the policy does not prohibit AE from conducting a cost of service study

[100] AE Ex. 2 at 7.
[101] AE Ex. 2 at 5.
[102] AE Ex. 1 at 129; AE Work Paper WP D-1.2.7.
[103] ICA Ex. 2 at 8; 2WR Ex. 11 at 5.
[104] ICA Ex. 2 at 8 & Schedule DJE-1.
[105] AE Ex. 1 at 21.

in a shorter timeframe, and a three-year amortization period helps ensure that there is not an over-lapping of rate case expense recovery periods between filings. AE points out that preparation of a cost of service study and rate application, conducting public outreach, and the formal IHE process typically takes well over a year, and rate case expenses are incurred throughout this period.

The IHE agrees that over-lapping rate case expense recovery periods should be avoided and that a three-year period for the recovery of expenses is appropriate. As noted by AE, a three-year recovery period is typical of how other utilities collect rate case expenses. A recovery period of less than the five years as allowed under the City of Austin's Financial Policy No. 17 is reasonable because it balances the interests of the utility in obtaining cost recovery with the interests of ratepayers by mitigating rate impacts and spreading the cost over the period that rates are likely to be in effect. Accordingly, the IHE recommends that AE collect $1,791,000 in rate case expenses associated with this proceeding over a three-year period.

g. Town Lake Center

The Town Lake Center (TLC) is a commercial building on Barton Springs Road purchased by AE in 1989 and used as a headquarters building until April 2021, when AE acquired a new building in the Mueller Development as its headquarters. AE continues to maintain certain information technology equipment at TLC. AE anticipates that it will transfer use of TLC to the City of Austin Financial Services Division (FSD) for general municipal purposes in FY 2023, but has not finalized the terms of the transfer nor executed a memorandum of understanding for the transfer.[106] Because TLC is currently owned by AE, no adjustment to the revenue requirement was made to reflect potential proceeds from the sale of the facility.[107]

Although the TLC has not been transferred to the FSD, 2WR proposes to amortize $30.5 million as an offset to AE's revenue requirement.[108] AE responds that 2WR's proposal should be rejected for several reasons. First, AE and FSD have not entered into or agreed to a memorandum of understanding for the sale and transfer of TLC. Second, AE and FSD have not specified the amortization period, interest rate, or payment schedule.[109] As a result, AE argues that 2WR's

[106] AE Ex. 3 at 20.
[107] AE has removed all operating costs of TLC from the revenue requirement and therefore no costs have been allocated to base rates.
[108] 2WR Ex. 1 at 5.
[109] AE Ex. 3 at 21.

proposal does not meet the criteria of a known and measurable adjustment and should be rejected.[110]

The IHE concludes that it is premature to amortize the TLC as an offset. Although the transaction is clearly contemplated – AE has removed all operating expenses of the TLC from its revenue requirement – the transaction has not yet occurred and the terms of the transaction are unknown.[111] The IHE recommends no adjustment to the revenue requirement associated with a potential, future sale of the TLC.

h. Other Expenses

Fayette Power Plant

The FPP is a coal fired generation unit in Fayette County. AE jointly owns FPP units 1 and 2 with the Lower Colorado River Authority (LCRA). AE has attempted to exit its share of FPP, but so far has been unable to reach a mutually acceptable agreement with LCRA to do so.[112] AE notes that the plant is expected to continue to remain in service generating electricity for the foreseeable future, and AE's obligations under the City's participation agreement with LCRA continue.[113]

Sierra Club, Public Citizen, and Solar United Neighbors (SCPC/SUN) argues that all of the costs of FPP should be disallowed because "there is no evidence in the record supporting the prudence of the utility's continued investment in th[e] plant."[114]

In response, AE notes that it does not directly operate the plant. Although AE has some oversight responsibilities as a participant, the day-to-day spending decisions are made by the operator, LCRA, and AE has a contractual obligation to pay its allocated share of these costs. AE cannot unilaterally decide to spend less on FPP as it can with other AE-owned generation assets.

AE further responds that excluding the costs associated with continued ownership and operation of FPP from base rates would be confiscatory and at odds with basic ratemaking principles. AE explains that FPP is operational and provides benefit to AE's customers and the ERCOT grid. AE presented evidence supporting the reasonableness of the costs. AE provided

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[110] AE Ex. 3 at 21. If, however, an adjustment would be made as a result of the proceeds, AE proposes a reduction would be made to internally generated funds for construction in Schedule C-3.
[111] AE Ex. 3 at 21.
[112] AE Ex. 3 at 22; *see also* Austin Energy Announces Update to Generation Portfolio (Nov. 1, 2021) https://austinenergy.com/ae/about/news/news-releases/2021.
[113] AE Ex. 3 at 22.
[114] SCPC/SUN Brief at 2, 5-10.

power production costs, which include FPP fuel, labor, routine maintenance, system control, and dispatch costs.[115] AE notes that the O&M expenses for FPP were not separately identified in the RFP because AE did not make a related adjustment to the historical FY 2021 amount. AE, however, provided the capital spending for FPP in the RFP.[116] AE states that the test year amount was based on the three-year average of actual historical expenses.

The IHE finds SCPC/SUN's position to be unreasonable. AE's costs associated with FPP are supported by the evidence. The plant is used and useful and it is appropriate for the costs associated with the plant to remain in AE's rates. The IHE recommends that AE's costs to operate and maintain FPP are reasonable and necessary based on ratemaking and cost recovery principles and should be approved.

Nacogdoches Power Plant

Paul Robbins proposed that lowering the cost of Nacogdoches Power Plant be analyzed.[117] Mr. Robbins proposed two potential points of savings associated with the plant.[118] Mr. Robbins conditioned his recommendation on the plant being included in base rates. AE provided evidence that costs associated with Nacogdoches are not included in base rates. AE points out that the costs are instead recovered through the Power Supply Adjustment (PSA), which is outside the scope of this rate review. The IHE agrees with AE that Mr. Robbins' recommendations are not ripe for consideration in this case.

2. Depreciation Expenses and Amortization of Contributions in Aid of Construction

Contributions in aid of construction (CIAC) are contributions from customers that offset the cost of building infrastructure. CIAC revenues reduce the revenue requirement of a utility. AE notes that CIAC and its impact on base rates are discussed in Section 4.2.2 of the Base Rate Package.[119] AE also reflected CIAC on Schedule C-3 and the associated workpapers in the Base Rate Package.[120]

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[115] AE Ex. 1 at 30.
[116] AE Ex. 1 at 93.
[117] P. Robbins Ex. 1 at 11.
[118] P. Robbins Brief at 10.
[119] AE Ex. 1 at 31.
[120] AE Ex. 1 86, 93-94, 97-98.

2WR argues that it has not received an answer as to how AE books and tracks the CIAC funded capital or how it is treated in the COS Study.[121] AE contends it has responded to 2WR's questions about CIAC at both the second technical conference[122] and in its response to 2WR RFI 3-7.[123] The IHE does not view the CIAC-related information AE provided as deficient.

2WR recommends that AE be required to track capital paid for with CIAC for purposes of rate setting and that the IHE recommend City Council direct the Electric Utility Commission (EUC) to supervise a study addressing growth.[124]

In response, AE states that in 2014 City Council adopted a resolution (City Council Resolution No. 20140612-057) directing the City Manager to "plan for full cost recovery of line extensions, with an exception for certain affordable housing," which AE points out has been done. AE also states that, at its June 13, 2022 meeting, the EUC discussed the CIAC policy and the allocation of system growth costs. AE claims that the EUC voted that City Council should review the CIAC policy and AE should provide a presentation to the EUC regarding the CIAC policy. As a result, AE argues 2WR's recommendations are unnecessary because the EUC will be reviewing the CIAC policy over the next few months and making recommendations to City Council on possible revisions.

The IHE has no reason to doubt the veracity of AE's representations regarding the EUC's review of the CIAC policy. Accordingly, the IHE agrees with AE that EUC's planned review and oversight should satisfy 2WR's request for a review of capital paid for with CIAC.

Mr. Robbins argues that AE is not following City Council's policy to have growth pay for itself. AE responds that its CIAC policy as reflected in the design manual requires collection of 100% of the costs for line extensions and new infrastructure associated with requests for new electric service, with an exemption for certain affordable housing. AE points out that a customer applying for new service will be charged all estimated costs for labor and material required to modify existing infrastructure and to extend service from AE's existing infrastructure to the customer's point of service to serve the requested load. This would include the service drop and meter. The IHE agrees with AE that Mr. Robbins has provided no evidence that AE is not following the intent of City Council.

[121] 2WR Ex. 1 at 3.
[122] AE Responses to Questions Related to Technical Conference #2 at 22-24 (Bates 53-55) (May 27, 2022).
[123] AE Response to 2WR Third Request for Information at 48 (Jun. 22, 2022).
[124] 2WR Ex. 1 at 3.

3. Capital Expenditures

Discussion of the parties' contentions regarding capital expenditures, which focused on FPP, is located in Section II.B.1.h - Other Expenses, above.

4. Internally Generated Funds for Construction

AE funds capital projects through a combination of cash (equity) and debt. Internally generated funds for construction (IGFFC) represent the cash component available to help fund capital projects. AE attempts to fund capital projects using a combination of 50/50 cash and debt.[125] AE explains that this approach reduces overall carrying costs associated with higher levels of debt and is consistent with AE's financial policies. Specifically, Financial Policy No. 14 states that capital projects should be financed through a combination of cash and debt and that "[a]n equity contribution ratio between 35% and 60% is desirable."[126]

NXP recommends AE change the IGFFC level so that it targets 35% rather than the 50% currently used.[127] AE responds that, although NXP's recommendation falls within the lower end of the range set out in Financial Policy No. 14, it fails to take into account other relevant considerations. First, the range of potentially acceptable funding in Financial Policy No. 14 has to be balanced with the other financial policies, such as Financial Policy No. 6, as well as AE's objective to maintain its credit rating. AE points out that City Council instructed AE, at the conclusion of the 2012 Base Rate Review,[128] to prospectively implement a policy of 50% funding for IGFFC. AE argues that adopting NXP's suggestion would be contrary to the direction of City Council. Additionally, on June 28, 2022, Fitch downgraded AE to 'AA-.' Fitch cited AE's elevated leverage, which has steadily increased during the past three years, and weaker operating cash flows primarily driven by lower base rate revenues that contributed to the utility's rising leverage.[129] Adoption of NXP's recommendation would result in even greater levels of debt and put AE at risk for additional downgrades.

TIEC argues that AE's financial policies do not mandate a particular IGFFC. TIEC suggests that IGFFC be reduced to 40%.[130] AE responds that, although accurate, this suggestion overlooks City Council's direction on this point. AE reiterates that in 2012 the City Council

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[125] AE Ex. 6 at 23.
[126] AE Ex. 1 at 21.
[127] NXP Ex. 1 at 54-56.
[128] *See* City of Austin Ordinance No. 20120607-055, Part 7 (Jun. 7, 2012).
[129] AE Ex. 3 at 6.
[130] TIEC Ex. 3 at 13-15.

approved a policy dictating that AE implement a policy of 50% funding for IGFFC. AE points out that this directive is consistent with AE's other financial objectives.

The IHE agrees with AE on this issue. If the City Council has instructed AE to implement 50% funding for IGFFC, then AE is obligated to do so. The City Council's policy directives should be implemented by AE. The IHE recommends no change to AE's proposed IGFFC.

5. General Fund Transfer

IHE Recommendation Summary on General Fund Transfer Adjustment

AE seeks to include a $120 million general fund transfer (GFT) amount in its proposed rates based upon a known and measurable adjustment to the test-year GFT to align the GFT with the proposed base rates that, if approved, would be in effect for at least five years. As explained below, the IHE recommends that GFT be calculated in accordance with AE's financial policies using known data. While AE asserts it *has* calculated GFT in accordance with its financial policies and that AE cannot summarily change the GFT amount to a historical level, the IHE is persuaded that AE's proposed adjustment based on future revenues under new rates is too speculative, which is borne out by actual GFT payments. Without number-running, the IHE cannot recommend an actual revenue requirement. As a result, the IHE recommends that the GFT be set based on the test-year GFT of $114 million or, at most, the $115 million estimate that AE used for FY 2023.

AE's Position

AE argues for the inclusion of a GFT of $120 million for purposes of calculating its revenue requirement.[131] AE submits that the GFT is consistent with standard practice among MOUs and Texas Government Code § 1502.059. AE makes transfers to the City's general fund in lieu of paying franchise fees, taxes, and dividends, and also in lieu of earning a return on investment as is done with IOUs. AE notes that the transfer payment from AE to the City is invested directly back into the local community, rather than flowing to outside investors, which is a benefit to residents in Austin and those in surrounding communities. AE's Financial Policy Nos. 12, 13, and 17 provide for and prescribe how the GFT is determined. AE notes that, per Financial Policy No. 13, the GFT is calculated based on 12% of AE's three-year average revenues using the current year estimate and the previous two years' actual revenues less power supply and district cooling

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[131] Although it initially proposed a GFT of $121 million, AE has indicated it has reduced the proposed GFT to $120 million as a result of the reduction in the overall revenue requirement. *See* AE Brief at 22, n.104.

revenue. AE notes that the GFT is not based on earnings, margins, or profits.[132] The GFT is calculated and determined during the City's budget process. AE has made a GFT to the City since at least 1946.[133] AE argues that it does not have the discretion to reduce the 12% rate used to calculate GFT.

AE argues that the GFT calculation, which is based on its financial policies, is only used for annual budgeting purposes, not for ratemaking purposes. To that end, for purposes of the ratemaking case, AE calculated the GFT amount of $120 million based on the amount of revenue that is estimated from the test year alone, and not from the three-year average method prescribed by its financial policies. To do so, AE proposes a known and measurable adjustment to align the revenue requirement with the proposed base rates. AE submits that it is important to make this adjustment because the proposed base rates may be in place for five years (or longer) and the failure to align the GFT with base rates could result in AE under-recovering this cost.

Separately, AE argues that the GFT is a real cost of doing business that must be recovered from customers. AE submits that cost elements become revenue requirement and are therefore included in the GFT calculation. AE further submits that GFT is functionalized based on revenue requirements (excluding PSA costs and non-electric costs) and then, for the portion that is functionalized to the customer function, sub-functionalized based on revenue requirement. Thus, AE submits the portion of the GFT that ends up in the customer charge has been allocated based on the revenue requirement.

2WR's Position

2WR argues that the GFT used for calculating AE's revenue requirement should be calculated in accordance with AE's financial policies.[134] In addition, 2WR notes (as do other parties) that AE's proposed FY 2023 budget includes a GFT of $115 million, which was calculated in accordance with AE's financial policies.[135] Based on AE's financial policies and the proposed FY 2023 budget, 2WR recommends a reduction of the proposed GFT by $6,000,000.[136]

Regarding 2WR's argument that the GFT be allocated based on revenue,[137] the IHE agrees with AE that the GFT is an expense to AE and not a profit. The GFT is a cost that must be recovered

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[132] AE Ex. 1 at 21.
[133] AE Ex. 3 at 16.
[134] RFP, App. B, p. 21, Financial Policy No. 13.
[135] Tr., (July 15) at 38, Ls. 29-39 to -39, Ls. 1-38; TIEC Ex. No. 25.
[136] 2WR Brief at 7.
[137] 2WR Ex. 1 at 9-10.

from customers. As noted by AE, cost elements become revenue requirement and are therefore included in the GFT calculation. As the revenue requirement increases, so does the amount of the GFT.[138] Also as noted above, the GFT is functionalized based on revenue requirement (excluding PSA costs and non-electric costs) and then, for the portion that is functionalized to the customer function, sub-functionalized based on revenue requirement.[139] As explained by AE, the portion of the GFT that ends-up in the customer charge has been allocated based on the revenue requirement.

NXP's Position

NXP's position is that the $120 million GFT proposed by AE is unsupported, controverts AE's financial policies, and its inclusion in rates does not comport with longstanding ratemaking principles. NXP notes that the $120 million GFT represents approximately 18% of AE's requested base rate revenues.[140] NXP recommends a GFT based on the City's budgeted amount, resulting in a $7 million reduction to AE's proposed GFT amount.[141]

Separately, NXP submits that AE's inclusion of the GFT as part of the ratemaking case does not follow ratemaking standards common to the electric energy industry.[142] In that respect, NXP argues that AE fails to provide any information to substantiate how GFT is invested back into the local community.[143] NXP further argues that Texas Government Code § 1502.59 provides that a GFT is permitted "to the extent authorized in the indenture, deed of trust, or ordinance providing for and security payment of public securities[.]"[144] NXP further argues that Texas Government Code § 1502.59 relates to the payment of bonds and other expenses related to securities, bond defeasance, or a cash infusion to help the city meet its debt coverage covenants; however, there is no mention of these types of payments in AE's GFT description.[145]

NXP argues that the Texas Water Commission (TWC) has held in another case that municipal utility transfers to a city's general fund are acceptable if they reimburse the city for administrative expenses, but that the TWC indicated that unspecified transfers to the general fund would only be justifiable if they are needed to provide the city with adequate debt service

[138] AE Ex. 3 at 16.
[139] Per AE Financial Policy No. 13, this is the basis for the calculation of the GFT.
[140] NXP Ex. 1 at 55-56; TIEC Ex. 3 at 14.
[141] NXP Ex. 1 at 61.
[142] NXP Ex. 1 at 57.
[143] NXP Ex. 1 at 58.
[144] NXP Brief at 12; NXP Ex. 1 at 58.
[145] NXP Brief at 12; NXP Ex. 1 at 58.

coverage.[146] NXP submits that this logic is consistent with the standard ratemaking principle applicable to AE's proceeding that the cost of providing utility service should be the basis of rates.[147] NXP notes that AE has failed to explain how the GFT is related to utility services and failed to indicate how such funds will be used "for and securing payment of public securities" to assist the City as stated in Texas Government Code § 1502.59.[148] NXP submits that, in sum, AE's proposed GFT of $120 million is a backdoor tax on customers both inside and outside the City of Austin's city limits – a tax for which many communities in Texas would require a vote from informed citizens.[149]

The IHE is unpersuaded by NXP's argument that AE failed to establish that the GFT is related to utility service and therefore should not be included in ratemaking.[150] The GFT is paid in lieu of paying franchise fees, taxes, and dividends that a utility would otherwise have to pay to a city. At the end of the day, the GFT is an actual expense of AE that must be included for purposes of ratemaking.

CCARE's Position

Clean Affordable and Reliable Energy's (CCARE) position[151] is that AE overstated its test-year revenue requirement by increasing the GFT to the maximum allowed under the City's Financial Policies and to a level that exceeds recent transfers.[152] CCARE proposes that AE's proposed GFT should be reduced by $11 million. CCARE notes that AE's historical GFT is $110 million, with a historical average of 7.8% of operating revenues.[153] CCARE argues that AE has not provided any justification for increasing the GFT, and it should be reduced to $110 million, which is 10.9% of the proposed operating revenue.[154]

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[146] NXP Brief at 12; NXP Ex. 1 at 58-59, citing Pet. Ex. 5 at 25; JJJ-5 at 949-50; TWC Docket No. 7144-M, *In the Matter of Complaints of Springwoods Municipal Utility District, et al. against the City of Austin*, Findings of Fact Nos. 40 and 41.
[147] NXP Ex. 1 at 59.
[148] NXP Ex. 1 at 59.
[149] NXP Ex. 1 at 60.
[150] NXP Brief at 11.
[151] Although it did not file a Post-Hearing Brief in this proceeding, CCARE included its position with respect to GFT in its Position Statement filed on June 22, 2022 (Doc. No. 140).
[152] CCARE's Position Statement at 1.
[153] CCARE's Position Statement at 1.
[154] CCARE's Position Statement at 1.

As set out below in the IHE's analysis of TIEC's (and other parties' position), the IHE recommends that the GFT be set based on the test year GFT of $114 million or, at most, the $115 million estimate that AE used for FY 2023.

ICA's Position

ICA's position is that AE has not adequately supported its known and measurable adjustment to the GFT. ICA submits that AE's rate filing package did not use the three-year average method dictated by City Council policy.[155] ICA notes that the City Manager's budget request to the City Council includes a $115 million GFT in 2022 and 2023, which is $6 million less than AE's known and measurable adjustment assumption.[156] As explained below in the discussion of TIEC's arguments, the IHE generally agrees with the ICA on this point because AE's known and measurable adjustment is too speculative.

In addition, the ICA submits that because the GFT is itself included in the base rate revenue requirement on which it is calculated, it is necessary to capture the effect of other revenue requirement adjustments and recognize the effect of the GFT on GFT. To do so, ICA proposes that the 12% factor must be "grossed up" by dividing the 12% by its complement, or 1-.12.[157] Accordingly, ICA proposes the grossed-up GFT factor is 12%/(1-.12), or 13.64%. ICA applied the grossed-up GFT factor to the revenue requirement as adjusted by ICA, and calculated an adjustment of $5,002,979 to the GFT included in the revenue requirement.[158] ICA submits this adjustment is a fallout of whatever revenue requirement adjustments are ultimately adopted in the final decision in this proceeding.

The IHE is unpersuaded by ICA's argument that AE needs to apply the "grossed up" factor to the GFT to account for "GFT on GFT."[159] The IHE recommends that the GFT be calculated in accordance with Financial Policy No. 13.

TIEC's Position

TIEC's position is that the proposed GFT is excessive. While TIEC agrees that GFT is treated as an expense for purposes of calculating AE's revenue requirement,[160] TIEC submits that AE's calculation of the GFT for ratemaking purposes is flawed and unsupported. CCARE and

155 AE Ex. 11.
156 Tr. (July 15) at 39.
157 ICA Ex. 2 at 14-15.
158 ICA Ex. 2, Schedule DJE-1.
159 ICA Brief at 12.
160 TIEC Ex. 3 at 5.

NXP support TIEC's recommendation. As explained below, the IHE finds TIEC's argument for compliance with financial policy more persuasive in regards to a known and measurable adjustment to the test-year GFT to align the GFT with the proposed base rates that, if approved, would be in effect for at least five years.

As noted by TIEC, AE's Financial Policies call for the GFT "to not exceed 12% of AE three-year average revenues less power supply costs and on-site energy resource revenue, calculated using the current year estimate and the previous two years' actual revenue less power supply costs and on-site energy resource revenue from the City's Comprehensive Annual Financial Report."[161] TIEC notes that AE calculated its proposed GFT through a known and measurable adjustment by multiplying the maximum GFT percentage allowed (12%) by operating revenues that include *AE's requested revenue requirement*. TIEC contends AE should have used the test year GFT, which was calculated in this manner and actually paid to the City.[162] The proposed revenue requirement used by AE is still subject to approval by the City Council, and thus too speculative to meet the known and measurable standard.[163] TIEC also proposes that if the test year GFT is to be displaced by a calculation that includes the revenues approved in this case, that calculation should still include the average of the two historical years.

TIEC further points out that the GFT AE actually paid to the City in Fiscal Year 2021 (the test year) was $114 million and the amount that was approved in 2021 for payment in Fiscal Year 2022 was also $114 million.[164] At the hearing, AE conceded that that its actual proposed GFT for Fiscal Year 2023 based on AE's calculation that it provided the City Manager under its Financial Policies is only $115 million.[165] AE notes that the proposed FY 2023 budgeted GFT of $115 million is based on 12% of the three-year average revenues, minus revenues from PSA and District Cooling for FY 2020, FY 2021, and estimated FY 2022. The revenues for those years use existing base rates and not the proposed base rates, which would not be in effect until FY 2023. However,

[161] AE Rate Filing Package, Appendix B at Bates 21.
[162] TIEC Ex. 6 (City of Austin Approved 2021-22 Budget Excerpt) at Bates 002 ("In accordance with these average revenue calculations, the transfers for FY 2021-22 are calculated based on a rolling average of actual revenue from fiscal years 2018-19 and 2019-20 and estimated revenue in FY 2020-21.").
[163] TIEC notes that, as stated in its Rate Filing Package, AE acknowledges that a known and measurable adjustment is appropriate when (1) the adjustment is quantifiable, and (2) the adjustment reflects an investment or expense that either is used and useful in the delivery of electric service or will become so prior to the effective date of the supporting rate structure. AE Rate Filing Package at 27, n.11.
[164] TIEC Ex. 25 (COA Proposed 22-23 Budget Excerpt) at Bates 005.
[165] Tr. (July 15) at 39:30-37 (Dombroski Cr.); TIEC Ex. 25 at Bates 4-5.

TIEC argues that AE's projections of the GFT amount for future years, which are based in part on estimated future revenues, appear to be lower than the $120 million amount it is requesting.[166] TIEC proposes that rates should be set based on the test year GFT of $114 million or, at most, the $115 million estimate that AE used for FY 2023.

IHE Conclusions on GFT Test-Year Adjustment

The IHE recognizes that the proposed rates, if approved, could result in increased revenue for AE and that the GFT would therefore increase in future years. AE also explained that "[t]he budget process is separate from the rate setting process. The budgeted GFT is calculated pursuant to financial policies. The $120 million GFT is the amount AE would expect to pay over the tenure the proposed base rates are in effect."[167] But there are problems with AE's argument: (1) the three-year average from the financial policies will be followed to calculate the actual GFT in future years, and (2) while the three-year average includes one estimated year, AE's single-test-year estimate of $120 million does not consider two prior years of actual GFT payments and is contradicted by the actual GFT of $114 million for the test year. The IHE therefore agrees with the position of TIEC and other parties arguing that AE's proposed GFT – to the extent that it relies on an as yet unapproved revenue requirement – is too uncertain to be known and measurable. AE's estimate also does not follow the City's financial policies, which will be followed to determine the actual annual GFT in future years. Without the benefit of number-running, the IHE recommends that the GFT be set based on the test year GFT of $114 million or, at most, the $115 million estimate that AE used for FY 2023, both of which were calculated consistent with the financial policies.

Outside-City Customers Adjustment for GFT

Homeowners United for Rate Fairness (HURF) is a non-profit organization of residential ratepayers living outside the City that was originally formed to appeal the City's rate ordinance, initially passed on June 7, 2012, and amended during the city's budget process in September 2012. HURF argues, and has historically argued, for a reduction to the revenue requirement for customers outside the City to recognize that those customers do not receive the benefit of the utility's revenues transferred to the City's GFT. HURF contends that this protects outside-city

[166] *See* TIEC Ex. 25 at Bates 4 (showing projected GFTs for 2024 and 2025 that increase only slightly from the 2023 level, which is $115 million).
[167] AE Brief at 22.

customers of AE from discriminatory and excessive electric rates, used to pay for City services they do not receive. HURF notes that, in the past, a reduction to the revenue requirement was spread across the residential customer class as well as the commercial classes that had previously been above cost of service. HURF's primary policy argument for the discount is that its customers receive no direct City services, so the GFT provides no direct benefit to HURF customers. In addition to the policy argument, HURF argues that the settlement agreement in PUC Docket No. 40627, the appeal of AE's 2012 Base Rate Review, precludes outside-city customers from being subject to the GFT.[168]

AE responds that the settlement in Docket No. 40627[169] was a negotiated, "black-box" settlement that did not specifically address the GFT. The base rate reduction provided to outside-city customers in 2012 was through a general reduction to the revenue requirement, not through a reduction in GFT.[170] AE argues that it is no longer obligated under that agreement, and HURF's proposed reductions to rates for outside-city customers should be rejected.

AE also argues that HURF is incorrect in claiming that the GFT should not apply to outside-city calculations.[171] The GFT is calculated in accordance with AE's Financial Policy No. 13.[172] AE posits that, because revenue from outside-city customers is included in the calculation of the GFT, cost causation dictates that outside-city customers are allocated their share of this cost. AE notes that Texas Government Code § 1502.059, which specifically authorizes the transfer of revenue of any MOU to the municipality's general fund, does not distinguish between inside-and outside-city customers. Finally, AE argues that participants did not agree in 2012 that outside-city customers derive no benefit from the City's expenditures of those funds.[173] While AE believes that all customers benefit from services resulting from the GFT, AE claims that there is no requirement that AE be required to demonstrate any direct benefit to customers.[174] Finally, AE claims that

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[168] HURF Brief at 1.
[169] *Petition By Homeowners United for Rate Fairness to Review Austin Rate Ordinance No. 20120607-055*, Docket No. 40627, Final Order (Apr. 29, 2013).
[170] AE points out that the final settlement in PUC Docket No. 40627 section (25 [E]) states that "the Signatories agree that their request that the Commission enter an order consistent with the Agreement is the result of negotiation and is not intended to have precedential value with respect to any particular principle, treatment, or methodology that may underlie the Agreement."
[171] HURF Ex. 1 at 1.
[172] AE Ex. 1 at 21.
[173] HURF Ex. 1 at 1.
[174] By way of comparison, IOUs pay dividends to shareholders regardless of their location without having an obligation to demonstrate its customers benefit from those payments. In contrast, the GFT is used to fund City services. For the

HURF has provided no evidence to support its position that outside-city customers derive no benefit from the City's expenditure of the GFT.

The IHE identifies two primary issues presented by HURF's position. The first is an evidentiary issue and the second is a matter of policy for the City Council to determine. HURF claims that outside-city customers derive no benefit from the City's expenditure of the GFT. AE disagrees and claims HURF presented no evidence that this is true. It is unclear to the IHE whether outside-city customers benefit from the GFT. Conceivably, a person does not have to live within the city limits to benefit from city services while in the city, such as emergency services, parks and recreation, and infrastructure improvement. On the other hand, AE claims that, legally, it does not have to demonstrate that outside-city customers actually benefit from GFT. Indeed, Texas Government Code § 1502.059 is broad, does not distinguish the source of utility system revenues included in a GFT, and states the City may use GFT funds for "general or special purposes." The term "special purposes" suggests a benefit that may not include all city residents, in the same way HURF argues that expenditure of GFT may not benefit outside-city customers. Although AE claims HURF failed to produce evidence in support of its position, AE generally has the burden of proof in this matter. While HURF is the party making this claim, on an issue as important as the GFT's benefit to outside-city customers, the IHE is reluctant to shift the burden to HURF on this matter. Nonetheless, the IHE is persuaded that the law does not require a showing of the GFT's benefit to any particular customer or citizen. From a cost-causation perspective, the GFT is a cost that AE incurs to do business, which all customers must pay for. How the City uses the GFT it receives is a separate issue—one that AE does not control and Texas Government Code § 1502.059 does not limit.

But just as Texas Government Code § 1502.059 does not appear to limit how the City may use GFT funds, it also does not prohibit the City Council from addressing the policy implications of this issue. Because there is no direct evidence of benefit of GFT funds to outside-city customers, the City Council could decide that, as a matter of public policy, the GFT should not be considered in calculating outside-city rates.

Accordingly, the IHE does not recommend any adjustment to revenue requirement as a result of HURF's outside-city arguments, but highlights the policy issue for City Council.

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purposes of allocating the GFT, it is irrelevant whether inside-city or outside-city customers directly benefit from these services.

6. Debt

a. Debt Service Coverage Ratio

Debt service coverage ratio (DSCR) is the ratio of cash available for servicing interest, principal, and lease payments to the total annual debt payments the utility is required to make. TIEC explains that the DSCR is calculated as revenues less operating expenses (excluding depreciation and amortization) divided by the annual debt service payments.[175] AE notes that the debt service coverage ratio does not impact the revenue requirement. Pursuant to Financial Policy No. 6, AE must target a debt service coverage ratio of not less than 2.0x on electric utility revenue bonds.[176] AE explains that utilities with lower debt ratios (i.e., less leverage) and higher debt service coverage ratios have higher credit ratings, which result in lower borrowing costs for the utility, a savings that can be passed on to customers through lower annual debt service payments. AE states that a 2.0x coverage ratio aligns with debt service coverage ratios of other public power utilities across the country.[177]

TIEC notes that AE's requested DSCR is 2.32x, which is 16% higher than its minimum target of 2.0x.[178] TIEC argues that AE inappropriately included non-retail electric revenues in its calculation.[179] When non-retail electric revenues are removed, AE's requested DSCR is 2.50x.[180] TIEC recommends that AE's revenue requirement be adjusted to reflect a DSCR of 2.30x,[181] after excluding the non-electric retail revenues. According to TIEC, this will provide a lower cost to ratepayers, but is still comfortably above AE's targeted minimum 2.0x ratio.[182]

AE responds that TIEC's removal of non-electric revenue and expenses from the calculation is inappropriate because AE uses revenue bonds for its capital financing, which are secured by all of AE's revenues, regardless of source.[183] TIEC argues that the rates at issue are for

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[175] TIEC Ex. 3 at 8.
[176] AE Ex. 1 at 33.
[177] AE Brief at 23.
[178] TIEC Ex. 3 at 8-9.
[179] TIEC Ex. 3 at 15.
[180] TIEC Ex. 3 at 9; *see* Exhibit BSL-1.
[181] TIEC's calculations assume that AE's GFT is reduced to $110 million, based on AE's historical average. TIEC Ex. 3 at 12. TIEC points out that, if the GFT is reduced to $114 million based on rejecting AE's known and measurable adjustment, the calculated DSCRs would be even higher. The IHE recommends a GFT of $114 or $115 million.
[182] TIEC Ex. 3 at 14-17 (showing the various calculations of the DSCR implementing TIEC's recommendations); AE Rate Filing Package, Appendix B (AE Financial Policies) at Bates 21 ("In addition to these requirements, electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to ensure a minimum debt service coverage of 2.0x on electric utility revenue bonds.").
[183] AE Ex. 3 at 26.

AE retail electric customers only, not customers of AE's other services, such as district cooling or wholesale transmission.[184] TIEC notes that, even if a combined DSCR including both retail and non-retail electric revenues is considered, TIEC's revenue requirement proposals would still result in a 2.16x DSCR, which is above AE's minimum targeted 2.0x DSCR.[185] While this may be true, the IHE agrees with AE that it is inappropriate to exclude a source of revenue and its associated expenses from the debt service coverage ratio calculation, when the revenue bonds are secured by all of AE's revenues.[186]

TIEC's criticism of this approach is that AE's retail electric ratepayers should not pay more than their share of AE's overall DSCR. TIEC points out that AE's non-retail electric operations have a DSCR of approximately 0.67x,[187] meaning that AE's non-retail electric customers are not paying enough in rates to cover the debt that is used to provide their service, or coverage margin.[188] The IHE finds TIEC's subsidization criticism too indirect; TIEC's subsidization concern may be appropriate for potential policy consideration by City Council, but the argument does not directly address whether AE's DSCR is consistent with current policy and bond covenants.

AE criticizes TIEC's comparison of its recommended DSCR of 2.5x to a range of ratios from Fitch, which is 0.90x-3.96x.[189] First, AE reiterates that, because TIEC's 2.5x range does not include all revenues and expenses, it is a flawed ratio. Second, while AE's methodology to calculate DSCR complies with its financial policies and bond covenants, Fitch makes additional adjustments to develop its range of 0.90x-3.96x.[190] For instance, Fitch makes adjustments to its debt service coverage ratio that include items such as purchase power agreements and transfers.[191] Finally, AE notes that its rates are not calculated by relying on the Fitch Report.[192] The IHE agrees with AE that, so long as its approach is consistent with applicable policy and bond covenants, it should be approved.

Finally, TIEC recommends that AE's return is unnecessarily high by calculating a return on equity and comparing that to regulated for-profit entities as a benchmark. TIEC calculated a

184 TIEC Ex. 3 at 9.
185 TIEC Ex. 3 at 16-17.
186 AE Ex. 3 at 26.
187 Tr. (July 15) at 13:40-14:4; 2WR Ex. 3 at 2-3.
188 TIEC Ex. 3 at 8 ("The debt service coverage ratio measures a utility's ability to meet its debt service payments.").
189 AE Ex. 3 at 27.
190 AE Ex. 3 at 27.
191 AE Ex. 1 at 572-599.
192 AE Ex. 3 at 23, 27, citing AE Ex. 1 at App. 20-22.

12.0% return on equity versus a benchmark of 9.38%.[193] AE responds that it does not earn a return on equity.[194] AE contends that it is inappropriate to calculate a theoretical return for an MOU based on IOU methodology, because those entities have different capital structures. AE points out that its implied return on rate base of 7.9% using the cash flow methodology is significantly lower than TIEC's calculation.[195] The IHE agrees with AE that it is not appropriate to compare a for-profit IOU methodology or return to a non-profit MOU methodology and return.

b. Credit Rating

In this Base Rate Proceeding, AE has raised concerns over a recent downgrade of its credit rating by Fitch. On June 28, 2022, Fitch downgraded AE from 'AA' to 'AA-.'[196] AE notes that this downgrade assumes approval of the original $48 million base rate increase proposed by AE.[197] AE points out that its credit rating is important because AE relies on cash from retail sales and the sale of long-term debt (bonds) to fund capital needs.[198] A lower credit rating can increase cash collateral requirements on AE from its energy trading counterparties and could impact the terms and conditions in vendor contracts. AE argues that, not only would a lower credit rating raise costs, it is also contrary to the ratings of most utilities.[199]

AE notes that its rates are calculated in accordance with AE financial policies and bond covenants.[200] AE uses the cash flow methodology as outlined in Section 4.2 of the Base Rate Package.[201] Specifically, Financial Policy No. 6 stipulates that AE set its rates using the cash flow methodology which shall produce a minimum of a 2.0x debt service coverage;[202] however, AE made no adjustment to increase or decrease the proposed revenue requirement in this Base Rate Review to achieve a specific level of debt service coverage. AE notes that it does not set rates to

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193 TIEC Ex. 3 at 10.
194 TIEC Ex. 3 at 10.
195 AE Ex. 1 at 35.
196 AE Ex. 3 at 23-24. Fitch cited AE's elevated leverage, which has steadily increased during the past three years, and weaker operating cash flows primarily driven by lower base rate revenues that contributed to the utility's rising leverage. AE notes that it has lost $90 million over the past two years in part due to the existing base rate structure and declining average consumption in addition to rising costs in materials and equipment. AE's current financial condition has resulted in less than 150 days of cash on hand in violation of the City's financial policies.
197 AE Ex. 3 at 24.
198 AE Ex. 3 at 24-25.
199 AE Ex. 3 at 25-26.
200 AE Ex. 1 at 20-22; AE Ex. 3 at 23-25.
201 AE Ex. 1 at 28-29.
202 AE Ex. 1 at 20.

achieve a certain credit rating.[203] AE posits that its credit rating is the result of prudent management and favorable market conditions and not a product of applying criteria for a specific credit rating in its ratemaking.[204]

TIEC has challenged whether AE's concerns over its credit rating are legitimate. TIEC contends that its recommended revenue-requirement adjustments will allow AE to maintain an investment-grade credit rating and reliable access to debt-capital markets. TIEC argus that Fitch's recent downgrade of AE was only by one step.[205] TIEC contends that AE maintains a very healthy credit rating of AA-.[206]

TIEC argues that AE is above investment grade status because it has a credit rating much higher than four vertically integrated IOUs.[207] TIEC notes that AE is seven rungs above investment grade status with a credit rating much higher than the four vertically-integrated IOUs.[208] AE argues that TIEC's comparison of AE's credit rating to vertically integrated IOUs[209] is based on a misunderstanding of how an MOU operates as related to its credit rating and debt service coverage. AE points out that MOUs and IOUs have very distinct capital structures.[210] TIEC disagrees and argues that, while IOUs have access to equity from stock issuances, AE sets its rates to provide a cash margin to fund capital improvements,[211] which AE refers to as "equity" in its own financial policies.[212] In addition, while both MOUs and IOUs can issue debt, AE can issue municipal revenue bonds, which are seen as lower risk compared to the corporate bonds IOUs issue.[213]

AE does not have access to equity investments that IOUs enjoy, which TIEC's witness on credit ratings acknowledged.[214] As stated above, AE points out that the credit rating on debt is much more critical for an MOU than an IOU because, to fund capital needs, MOUs rely on cash

203 AE Ex. 3 at 23-24.
204 AE Ex. 3 at 23.
205 AE Ex. 3 at 6.
206 Fitch calculated AE's DSCR to be 1.5x, which is within the range for public power utilities with AA rated debt (0.90x-3.96x DSCR). TIEC Ex. 24; TIEC Ex. 3 at 10.
207 TIEC Ex. 3 at 6-7.
208 TIEC Ex. 3 at 6.
209 TIEC Ex. 3 at 6.
210 AE Ex. 3 at 24-25.
211 Tr. (July 14) at 11:20-34 (LaConte Cr.).
212 AE Rate Filing Package, Appendix B (AE Financial Policies) at Bates 21 ("Capital 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 contribution ratio between 35% and 60% is desirable.").
213 Tr. (July 14) at 6:5-8 (LaConte Cr.).
214 Tr. (July 14) at 5:40-46-6:3-10 (LaConte Cr.).

from retail sales and the sale of long-term debt (bonds), instead of access to equity investments used by IOUs.[215] Therefore, the credit rating on debt is much more critical for an MOU than an IOU.

AE reiterates that a lower credit rating would be harmful to ratepayers in a number of ways. The most obvious impact is that it would increase costs. Even according to TIEC's calculation, if AE were downgraded to an 'A' rating, AE's annual debt service cost would increase by $3.6 million per year.[216]

According to AE, its former 'AA' rating was well within the norm of retail public power providers according to the Fitch Peer Review.[217] There are 80 total retail public power providers in the Fitch 2021 peer review.[218] Of those 80, 51 (or 64%) are rated between 'AA+' to 'AA' with 21 being 'AA.'[219] There are only eight (or 10%) of retail public providers with ratings between 'A-' and 'BBB,'[220] which is the range of TIEC's comparator IOUs.

The IHE recommends that AE's concerns over its credit rating are legitimate due to its capital structure, and the very real potential for increased costs in debt service, vendor contracts, and energy trading. Having said that, TIEC and AE appear to agree that it is not prudent for a utility to pursue the highest credit rating possible without regard to the cost to ratepayers.[221] The IHE does not view AE's position to be that it is pursuing the highest credit rating possible, but rather that it is reasonable to take steps to avoid a further erosion of its credit rating and to endeavor for an upgrade back to 'AA.' The IHE finds this to be a reasonable approach for AE.

Accordingly, the IHE concludes that AE's proposed cash flow methodology and DSCR of 2.32x is reasonable and appropriate. It allows AE to meet its debt obligations, ensure sufficient margin for operations, and maintain its current credit rating.

7. Cash Margin

Not addressed by the parties.

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215 AE Ex. 3 at 24-25.
216 TIEC Ex. 3 at 8.
217 AE Ex. 3 at 25, *citing* AE Ex. 1 at App. 572-599.
218 AE Ex. 3 at 25, *citing* AE Ex. 1 at App. 576-580.
219 AE Ex. 3 at 25, *citing* AE Ex. 1 at App. 576-580.
220 AE Ex. 3 at 25, *citing* AE Ex. 1 at App. 576-580.
221 TIEC Ex. 3 at 7-8; Tr. (July 15) at 42:28-29 (Dombroski Cr.).

8. Revenue Requirement Offsets

a. Late Payment Fees

Late payment fees are revenues AE receives from customers who have been late in paying their electric bills, and are an offset to AE's revenue requirement. AE made no adjustment to the test year late payment fee amount in the Base Rate Package. The ICA proposes an upward adjustment of $2.2 million[222] and 2WR proposed a similar adjustment.[223] The ICA excludes FY 2020 and FY 2021 due to the COVID pandemic and instead proposes an average of FY 2018 and FY 2019 to develop a late payment fee adjustment. The ICA notes the average annual amount of late fee revenue in the two years prior to 2020 is $5.55 million.[224] The test year amount of late payment fee revenues is $3.34 million.[225] 2WR's recommendation is similar in that they propose averaging prior year late payment fees. AE counters that it is improper to use FY 2018 and FY 2019 because those are two years prior to the current test year of FY 2021 and will be four years prior to the FY in which the base rates approved in this proceeding will become effective (FY 2023).

Although the ICA and 2WR raise a valid concern, the IHE agrees with AE on this issue. AE's rate package uses a FY 2021 test year, not 2018, 2019, or an average of prior years. Most importantly, however, the COVID pandemic and its impacts, whatever they may be, are ongoing. Reaching back to a time before the pandemic does not reflect the current and ongoing reality of the pandemic's effects, which can be viewed as the new normal.

Furthermore, AE has proposed a known and measurable adjustment to the late-payment fee offset that captures more recent data, consistent with a post-COVID focus. AE notes that the test year included only eight months of late fees due to AE waiving them in response to COVID and Winter Storm Uri.[226] As a result, AE seeks a known and measurable adjustment to late payment fess of $1,154,575.[227] This was derived using a 12-month total of late payment fees billed beginning May 2021 through April 2022, which is after the expiration of COVID and Winter Storm

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[222] ICA Ex. 3 at 16-17.
[223] 2WR Ex. 1 at 5.
[224] AE Response to 2WR 1-11.
[225] WP E-5.1.
[226] AE Ex. 4 at 7.
[227] AE Ex. 4 at 7.

Uri policies that temporarily eliminated late payment fees.[228] The IHE recommends adoption of AE's adjustment as it is focused on more recent data than that proposed by ICA and 2WR.

9. Other Revenue

Facilities Rentals

AE made three adjustments to Other Revenues, including reducing Facility Rentals by $1,836,826[229] to reflect an adjustment for pole attachment revenue that it does not expect to collect from a customer. The revenue has been disputed by the customer for more than a year, and AE does not expect that the amount will be recovered.

ICA proposes that no adjustment be made to Other Revenues for Facility Rentals.[230] ICA argues that, although AE established that the amount is in dispute, this does not establish with a reasonable degree of certainty that there will be no recovery of the balances due.[231] ICA notes that AE is still seeking to recover the amount in dispute.[232] As a result, ICA argues AE failed to show that the disputed bills for facilities rentals will not be unrecoverable or that the ongoing revenues from this source will be zero prospectively. ICA recommends that the adjustment to reduce Other Revenues by $1,836,826 be eliminated.[233]

AE responds that it follows Generally Accepted Accounting Principles, which require AE to reduce receivables not expected to be collected. Because AE does not expect to collect this amount, it is required to adjust its revenues and the $1,836,826 revenue was negated in AE's financial statements as uncollectible, subject to an independent external audit for FY 2021.[234]

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.

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[228] AE Ex. 4 at 7.
[229] AE Ex. 1 at 172.
[230] ICA Ex. 2 at 12-13.
[231] ICA Ex. 2 at 12-13; ICA Ex. 2, Attachment ICA 4-6.
[232] See Response to ICA Request 8-3.
[233] ICA Ex. 2 at 13-14.
[234] AE Ex. 4 at 5.

10. Pass-Through Items

Although this is a base rate case, AE's COS Study includes pass-through costs in its analysis. AE contends that this allows the entirety of AE's business operations to be represented, ensuring that no cost has been missed or duplicated, which ensures transparency, and allows AE to represent estimated electric utility bills for different customers. AE notes that, having only base costs in the cost of service makes it difficult to represent the entire bill. AE notes that, as illustrated in the schedules contained within the RFP, all pass-through costs were quantified and only base costs were included for recovery through AE's proposed base rates.[235]

TIEC contends that pass-through costs should not be included in the cost of service analysis. TIEC argues that having pass-through costs represented in the cost of service impacts the allocation of service area lighting. As noted above, AE agrees that pass-through costs should not impact the cost of service. However, including pass-through costs represented in the analysis does not cause the recovery of service area lighting costs to be impacted.

TIEC argues that AE should remove pass-through costs (with the exception of area street lighting costs) from its COS Study. TIEC notes that AE admits that its pass-through costs are not at issue in this proceeding and are not subject to change.[236] TIEC points out, however, that pass-through costs change dynamically over time as the underlying costs change, such as AE's fuel and purchased power costs.[237] TIEC contends that including these dynamic pass-through costs in the COS Study skews the outcomes for base rate allocations by reflecting items that (a) will frequently change over time, and (b) cannot be changed here.

According to TIEC, all pass-through costs, with the exception of area street lighting, should be removed from AE's COS Study. TIEC explains that the amount of area street lighting pass-through costs should be derived in AE's COS Study. TIEC witness Jeffry Pollock developed a version of the COS Study with pass-through costs removed, which reduces AE's proposed base revenue requirement to $705 million.[238]

AE explains that service area lighting costs are allocated to customer classes based on revenue requirement (including pass-through costs). However, service area lighting for the City is a pass-through cost, which is not being addressed in this Base Rate Review. Thus, although there

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[235] AE Ex. 6 at 27.
[236] TIEC Ex. 1 at 18.
[237] TIEC Ex. 1 at 18.
[238] TIEC Ex. 1 at 17-19; Exhibit JP-2.

is an allocation shown on Schedules G-6 and G-7, these allocations are not proposals for how to recover this cost. Because the service area lighting pass-through charge is not being set in this Base Rate Review, AE did not develop a special allocator for service area lighting that accounted for all of the various limitations on the recovery of this cost. AE points out that, no matter how service area lighting costs are allocated to customer classes in the Base Rate Package, it will have no impact on the base cost of service or resulting proposed base rates. As long as the allocator for service area lighting is the same between these two schedules, meaning there is not a disagreement within the model as to how this cost is allocated, there is no impact on the identified base cost of service for any customer class.[239]

To support its claims, TIEC provided a table from TIEC witness Pollock (JP-2) that shows the reduction in total AE's base revenue requirement to $705 million.[240] That table, however, does not provide detail as to how each element of the proposed reduction in pass-through costs impacts AE's proposed rates. TIEC witness Pollock did provide an example with regard to Energy Efficiency Services (EES) costs,[241] stating that AE allocates $2,319,031 to the Primary ≥ 20 megawatt (MW) HLF class customers, who are not charged for EES costs under the AE tariff.[242] TIEC claims this has the effect of raising the class's revenue based on costs those customers are not supposed to pay.[243] The IHE confirms that the figures identified by Mr. Pollock are reflected on that schedule (Schedule G-6).[244]

However, AE provided unequivocal testimony that only base costs were included for recovery through AE's proposed base rates. AE witness Grant Rabon testified:

> . . . In the end, as illustrated in the schedules contained within the Base Rate Filing Package, all pass-through costs were quantified and only base costs were included for recovery through Austin Energy's proposed base rates.[245]

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239 AE Ex. 6 at 28.
240 TIEC Ex. 1 at 17-19; Exhibit JP-2.
241 *See, e.g.*, AE Ex. 1, Appendix C at Bates 251 (showing that Primary Voltage ≥ 3<20 MW are assigned $1,518,350 relating to Energy Efficiency Programs, and Primary Voltage ≥ 20 MW are assigned $2,319,031 relating to Energy Efficiency Programs); *see also* AE Ex. 7 at 5.
242 AE Ex. 1, Appendix F at Bates 472 ("Charges for Service Area Lighting (SAL) and Energy Efficiency Services (EES) do not apply under this rate schedule.").
243 AE Ex. 1, Appendix C at Bates 251. Appendix C shows the Energy Efficiency Program cost is included in the amount for Total Production (line 9), which is then added into the Total Cost of Service (line 46) and the Adjusted Total Cost of Service (line 53). AE Ex. 1 at 251.
244 AE Ex. 1, Appendix C at Bates 251.
245 AE Ex. 6 at 27.

Focusing on the issue of service area lighting costs, AE witness Rabon offered parties the opportunity to challenge this assertion:

> . . . no matter how service area lighting costs are allocated to customer classes in the Base Rate Filing Package, it will have no impact on the base cost of service or resulting proposed base rates. To prove this, I invite any interested party to change the allocator used to allocate service area lighting to customer classes on Schedule G-6 and Schedule G-7. As long as the allocator for service area lighting is the same between these two schedules, meaning there is not a disagreement within the model as to how this cost is allocated, there is no impact on the identified base cost of service for any customer class.[246]

The IHE is persuaded that, despite the inclusion of pass-through costs in AE's COS Study, all pass-through costs were merely quantified and only base costs were included for recovery through AE's proposed base rates.[247] The IHE recommends no adjustment to the cost of service analysis for pass-through costs.

NXP argues that AE should charge the City for the cost of street lighting service rather than recovering this cost through other customer classes in the Community Benefit Charge (CBC).[248] AE points out that City Council considered this issue in the 2012 Base Rate Review and determined that street lighting within the City provides numerous benefits to the community, including increased public safety for drivers, riders, and pedestrians. Accordingly, City Council determined that it is appropriate to collect the cost of street lighting service from all customers through the CBC.

The IHE agrees with AE. City Council has addressed this as a matter of policy, and the IHE proposes no change to the collection of street lighting service costs from all customers through the CBC.

C. Present Revenues and Billing Determinants

AE used 2021 as the historical test year in preparing its cost of service in this matter, including sales and base revenues. TIEC argues, however, that AE's 2021 test-year data should be adjusted to account for the anomalous, non-recurring impacts of Winter Storm Uri. TIEC claims that AE's application overstated its test-year base revenue deficiency because it failed to adjust revenues for Winter Storm Uri, even though AE claimed to have normalized test-year sales and

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[246] AE Ex. 6 at 28.
[247] AE Ex. 6 at 27.
[248] NXP Brief at 14.

revenues.[249] TIEC explains that the outages resulting from Winter Storm Uri depressed test-year kWh sales and base revenues, but AE did not adjust test-year sales to remove this aberration.[250]

TIEC claims that AE's test-year *kWh sales* were well below actual sales in 2018 through 2020.[251] TIEC argues that using artificially low sales numbers results in artificially lower rates on a per-unit basis, since the revenue requirement must be recovered through fewer billing determinants. If actual sales numbers are ultimately higher, TIEC's concern is that AE will over earn.

TIEC also claims that, despite strong customer growth in recent years, *total test-year sales* were only 0.6% higher than the average for the four prior fiscal years.[252] TIEC notes that test-year sales were also significantly lower on a per-customer basis—residential customers used nearly 2% less energy per customer and commercial and industrial (C&I) customers used 5.2% less per customer as compared to the average usage in 2017 to 2020.[253] TIEC claims that the only plausible explanation for this blip in sales is Winter Storm Uri.

TIEC also notes that AE projects increasing sales and revenues going forward. AE's 2020 Resource Plan forecasts both continued peak load growth and energy sales growth after 2021.[254] Mr. Pollock's Table 2 illustrates AE's projected growth in weather-normalized base revenues out to 2027.[255]

TIEC concludes that, if AE fails to appropriately adjust for Winter Storm Uri's impact on test-year sales and revenues, AE's projected revenue deficiency will be overstated and the resulting rates will over-collect approximately $24.3 million per year.[256] As a result, TIEC posits that test-year sales, revenues, and billing determinants must be restated to reflect expected sales and revenues. TIEC notes that AE refused to produce detailed projections of sales and revenues beyond FY 2021 or historical sales data by customer class, notwithstanding that AE has relied on such projections for its own purposes.[257] Without the information needed to make a precise adjustment

[249] TIEC Ex. 1 at 3, 9.
[250] TIEC Ex. 1 at 7, 9.
[251] TIEC Ex. 1 at 7-8.
[252] TIEC Ex. 1 at 10, Table 1.
[253] TIEC Ex. 1 at 10.
[254] TIEC Ex. 1 at 11, Table 2.
[255] TIEC Ex. 1 at 11.
[256] TIEC Ex. 1 at 7-8, 12.
[257] TIEC Ex. 1 at 12 (citing AE Objection to TIEC 4-10 and the Rate Filing Package at 117).

based on AE's own projections,[258] TIEC recommends reducing AE's claimed revenue deficiency by $24.3 million based on Mr. Pollock's analysis.[259]

AE objects to using the average energy consumption for customers over the four years from FY 2017 through FY 2020 as a basis for judging the billing determinants in the test year.[260] According to AE, the historical energy sales Mr. Pollock used are not weather normalized.[261] AE also argues that this approach fails to recognize that average residential energy sales are on a multi-year downward trend, as outlined extensively in AE's Base Rate Package.[262]

AE also objects to TIEC's attempt to use future billing determinants for FY 2023 to set base rates for AE.[263] AE argues that this approach is reflective of a future test year concept, which is incongruent with the historical test year approach. AE concludes that adoption of TIEC's recommendations would misalign AE's historical FY 2021 costs, adjusted for known and measurable events, with billing determinants from a future year—specifically FY 2023.

The IHE generally agrees with AE's criticism of TIEC for using an average of past non-weather normalized energy sales for judging billing determinants in the test year.[264] The IHE also agrees that looking to future billing determinants to set base rates for AE would misalign with AE's historical FY 2021 costs.[265] The IHE, however, agrees with TIEC that these were attempts to address the underlying problem of how AE adjusted for Winter Storm Uri's impact on sales and base revenues in the test year. Despite TIEC's focus on past-test-year averages and future years for billing determinants, Mr. Pollock testified that it is better to analyze the test year – so long as enough information is available.[266]

The genesis of this issue is that, although AE represents test year kWh sales as weather normalized, it also represents in an RFI response to TIEC that Winter Storm Uri had *no* impact on 2021 sales and base revenues. TIEC's RFI 3-5 requested a copy of AE's analysis of the impact of

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258 Tr. (July 14) at 15:4-6 (Pollock Cr.) (explaining that it's better to take the test year and do a forensic analysis but the information was not available).
259 TIEC Ex. 1 at 14.
260 TIEC Ex. 1 at 12-14.
261 AE Ex. 6 at 26-27.
262 AE Ex. 6 at 26-27.
263 TIEC Ex. 1 at 12-14.
264 AE Ex. 6 at 26-27.
265 AE Ex. 6 at 26. The IHE granted limited discovery on this issue. IHE Order No. 5 at 3; AE Supplemental Response to TIEC's 4th RFI (July 7, 2022).
266 Tr. (July 14) at 15:4-6 (Pollock Cr.) (explaining that it's better to take the test year and do a forensic analysis but the information was not available).

Winter Storm Uri on its test-year energy sales and base revenues. AE's response to TIEC's RFI 3-5 was:

> No responsive document exists. There was no impact on Austin Energy's test year energy sales and base revenues from Winter Storm Uri. Energy sales are weather normalized and current rates are applied to the weather normalized sales to calculate test year revenues.[267]

It is unclear to the IHE how AE took Winter Storm Uri into account based on this RFI response.[268] In its brief, AE describes the impact of Covid *and Winter Storm Uri* on AE's finances as "relatively modest."[269] Without minimizing the impact of the storm in any way, the IHE understands that it was roughly a four day event (in terms of the storm itself). Nevertheless it was a significant event from an electric energy perspective throughout the state. Instead of looking to the past and future to reconcile the test year, the IHE simply prefers that AE better explain how the storm had no impact on test year energy sales and base revenues.

The IHE agrees with TIEC that AE's 2021 test-year kWh sales were below actual sales in 2018 through 2020. This is clearly reflected by Mr. Pollock in his Table 1.[270] And total energy sales in 2021 were only 0.6% higher than the average for the four prior fiscal years, despite customer growth.[271] The IHE recognizes that one of AE's clearly stated concerns in the Base Rate Package is that average residential energy sales are on a multi-year downward trend.[272] But this fact alone does not explain how 2021's residential *and* C&I kWh sales were the lowest since 2017, despite fluctuations in those prior years in both categories.[273]

The IHE recommends that AE should better explain how Winter Storm Uri had no impact on test-year sales, revenues, and billing determinants before these figures are adopted. AE's claim that Winter Storm Uri had no impact may be correct. And to the extent that City Council requires a firm determination from the IHE, AE has provided evidence that sales were weather normalized. But the IHE strongly prefers that TIEC's legitimate questions be addressed before test-year sales, revenues, and billing determinants are established by City Council. To that end, the IHE

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[267] AE Response to TIEC RFI 3-5 (June 6, 2022).
[268] Perhaps the answer resides within AE's evidence or the attachments and work papers to the Base Rate Package. However, in response to TIEC's arguments on this issue, AE's Brief only references pages 26-27 of Mr. Rabon's testimony and he does not directly address this issue. AE Ex. 6 at 26-27.
[269] AE Brief at 88.
[270] TIEC Ex. 1 at 7-8.
[271] TIEC Ex. 1 at 10; Table 1.
[272] AE Ex. 6 at 26-27.
[273] TIEC Ex. 1 at 10, Table 1.

understands that, depending on AE's answers to why there was no impact as a result of Winter Storm Uri or how weather normalization addressed any such impact, it may be necessary for AE to update test-year sales, revenues, and billing determinants, before they are adopted.

D. Miscellaneous

In its brief, AE noted several concessions regarding the Base Rate Filing Package. AE stated that, after reviewing the position statements of the participants, AE modified its position on several issues in its rebuttal testimony. Three of the additional adjustments related to non-cash nuclear decommissioning, interest on nuclear decommissioning, and the BAB subsidy are discussed below.

AE agrees with the ICA that a correction to the non-cash portion of the nuclear decommissioning contribution should be made. AE increased the cash needs by $4,662,375 when it should have decreased the cash needs by $4,662,375.[274] Thus, the overall impact was $4,662,375 times two, or $9,324,751, as noted by ICA.[275]

AE also determined that a portion of the cash contribution was funded from interest on the nuclear decommissioning trust. Given that interest income on the trust was not included as a source of revenue to offset the cash needs of the utility, as it was assumed to accrue in the trust (see Work Paper C-3.4.1), AE acknowledges that it should not have included this portion of the cash funding for nuclear decommissioning in the revenue requirement. Removing the portion of the cash contribution that came from interest income results in an additional $2,594,248 reduction to the revenue requirement as compared with what AE originally filed.[276]

Finally, AE determined that the interest expense on the Series 2010B BAB refunding was missing the subsidized portion in AE's original analysis. The subsidy was included as a source of funding in the analysis (see Work Paper C-3.4.1), but the interest expense the subsidy was offsetting was missing because the debt service used was net of the subsidy. Thus, AE has added the subsidy portion of the interest expense to the revised analysis. The subsidy portion was $1,849,557 in FY 2021 and $1,791,095 in FY 2022.[277]

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[274] AE Ex. 3 at 7.
[275] The original adjustment to this contribution was intended to remove the non-cash portion of this expense, given AE is using the cash flow approach to develop its revenue requirement. However, AE erroneously reversed the sign convention on the non-cash portion and increased the cash obligation, rather than decreasing the cash obligation. AE's Brief at 29.
[276] AE Ex. 3 at 7.
[277] AE Ex. 3 at 7.

III. Cost Allocation

A. Background

AE proposes a cost allocation method that AE asserts will allocate its pre-determined total cost of service to customer classes based on how each class uses electricity and the resulting demands placed on the electric infrastructure. AE contends that with this approach it aims to distribute costs as accurately as possible based on how much it costs AE to serve each customer class. AE emphasizes that these methodologies are officially recognized and commonly used in the utility industry and are in accordance with generally accepted practices. AE points out that these methodologies are recognized by the American Public Power Association (APPA), the National Association of Regulatory Utility Commissioners (NARUC), the National Rural Electric Cooperative Association (NRECA), and are consistent with the Public Utility Regulatory Act (PURA).[278]

AE's proposed cost of service methodology includes three general steps: (1) functionalization; (2) classification; and (3) class allocation.[279] Functionalization separates expenses/costs into major categories based on AE's primary business functions: generation (or production), transmission, distribution, and customer service. Classification further separates the functionalized costs into: (1) cost classifications based on the type of activity causing the costs: (a) customer-related;[280] (b) demand-related;[281] or (c) energy-related;[282] and (2) sub-functions that are sub-divisions within each business function (e.g., City-owned lighting). Class allocation then attributes the functionalized and classified costs to individual customer classes based on the cause

[278] AE Ex. 1 at 47.

[279] AE Ex. 1 at 48.

[280] AE explains: "Customer-related costs reflect the minimum amount of fixed costs (i.e., equipment and service) the utility needs to supply for customers to access the utility system. These are the cost of meters, service drops, meter reading, meter maintenance, and billing. These are costs that vary with the addition or subtraction of customers. These costs do not vary with usage..." AE Ex. 1 at 48.

[281] AE explains: "Demand, or capacity, costs are those costs associated with designing, installing, and operating the system to meet maximum hourly electric load requirements. Electric systems must be sized to meet peak requirements, even though average daily usages are below peak levels. Otherwise, the system would not be adequate to serve customers' demand for electricity on peak days. Accordingly, while these structures or units may not be fully utilized at all times, they must be designed and installed to meet the maximum peak demand that the utility plans to serve." AE Ex. 1 at 48.

[282] AE explains: "Energy-related costs are those costs that vary with the amount of electricity sold to or transmitted for, customers. Costs related to supply are classified as energy-related to the extent they vary with the amount of electricity purchased or generated by the utility for its customers." AE Ex. 1 at 48.

of the cost(s). Costs that are unique to a particular class will be directly assigned to that customer class, but otherwise, the costs are allocated amongst the classes.[283]

B. Functionalization

The first step in AE's cost allocation methodology is functionalization, by which AE separates its total cost of service into functions, or major categories based on AE's primary business functions.[284] AE has identified its primary business functions as production (i.e., generation), transmission, distribution, and customer service.[285] AE explains that cost assignment by function generally falls into two categories: direct assignments and derived allocations.[286] AE directly assigns costs that are readily identifiable to its specific utility function.[287] In other words, costs that are unique to a specific customer class are directly assigned to that customer class, and costs that cannot be directly assigned are allocated among classes based on the activities that cause the costs.[288] AE explains that derived allocators are allocation factors based on the sum, average, or weighted effect of amounts that have been directly assigned or allocated in prior steps in the analysis.[289]

1. Production Function

AE has identified the production function as one of its four primary business functions.[290] AE sells the energy it generates to the ERCOT market and must purchase from ERCOT all the power necessary to serve its own customers.[291] Additionally, because AE's generated energy is sold to the ERCOT market, AE's generation serves as a physical and financial hedge to its customers against ERCOT market price fluctuations for power; as prices for power in the ERCOT market increase, from time to time, so do revenues paid to AE for sales to ERCOT, thus mitigating the impact on AE's customers.[292] AE emphasizes that the generation hedge provides a direct

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283 AE Ex. 1 at 48-49.
284 AE Ex. 1 at 49.
285 AE Ex. 1 at 48, 50.
286 AE Ex. 1 at 50.
287 AE Ex. 1 at 50. AE offers the example that fuel is an expense solely related to the production function and is directly assigned to that function. AE Ex. 1 at 50.
288 AE Ex. 1 at 48-49.
289 AE Ex. 1 at 50.
290 AE Ex. 1 at 51.
291 AE Ex. 1 at 51.
292 AE Ex. 1 at 51.

benefit to its customers by shielding them from high price spikes in the ERCOT wholesale market.[293]

AE further explains that its variable production costs are recovered through the sale of energy into the ERCOT wholesale market.[294] AE then passes this revenue on to customers through the PSA.[295] However, AE clarifies that revenues from sales into the ERCOT wholesale market do not offset base-rate costs associated with AE's generation.[296] Instead, AE's revenues from off-system sales offset PSA costs, and it recovers fixed costs for its power production through base retail rates assigned to its customers.[297] AE also states the production function is used to appropriately assign fixed operating costs to the appropriate customer classes, and fixed production costs are classified as demand-related costs because they do not vary based on the amount of energy generated.[298]

AE states, and the IHE acknowledges, that while no participant takes issue with AE's classification of production costs, several participants disagree with AE's proposed allocation methodology, discussed at Section III.D Class Allocation.

2. Transmission Function

AE's transmission function is the second of its four primary business functions. AE owns a series of transmission and distribution lines through which it delivers electricity to homes and businesses. Although ERCOT oversees the operation of the transmission system, the PUC has exclusive jurisdiction over rates, terms, and conditions for the provision of wholesale transmission services. The PUC sets the rate AE is paid by those who use AE's portion of the transmission system and the rate AE pays as its share of statewide transmission costs to serve its load.[299] AE's transmission costs are recovered through the AE's Regulatory Charge.[300] No part of the transmission function has any impact or relevance to the base rates being set in this proceeding.

The IHE agrees that AE's transmission function does not impact the base rates to be set in this proceeding.

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[293] AE Ex. 1 at 51.
[294] AE Ex. 1 at 52.
[295] AE Ex. 1 at 52.
[296] AE Ex. 1 at 52.
[297] AE Ex. 1 at 52.
[298] AE Ex. 1 at 52.
[299] AE Ex. 1 at 52.
[300] AE Ex. 1 at 53.

3. Distribution Function

AE has identified the distribution function as the third of its four primary business functions. AE explains that AE connects the ERCOT transmission grid to more than 520,000 customer accounts through the local distribution power grid using over 12,000 miles of distribution lines. AE's distribution function includes all costs associated with operating and maintaining the distribution system, including capital expenses.[301] AE further explains that the distribution function has been sub-functionalized to encompasses primary substations, poles, and conductors; secondary poles and conductors; transformers; load dispatch; meters; and installations on customer premises.[302] AE asserts these sub-functions represent utility infrastructure used to provide customers with adequate and reliable electric service.[303]

AE states, and the IHE acknowledges, that while no participant takes issue with AE's classification of distribution costs, several participants disagree with AE's proposed allocation methodology, discussed in detail at Section III.D Class Allocation.

4. Customer Service Function

AE has identified the customer service function as the fourth of its four primary business functions.[304] AE maintains the customer service function includes all aspects of operations that are necessary to meet customer support requirements.[305] AE identifies several business functions within the customer service function, which can be sub-functionalized to include customer accounting (billing and collections), customer service, meter reading, bad debt (i.e., uncollectibles), key accounts, and economic development.[306]

The ICA disagrees with AE's sub-functionalization of customer service costs to include bad debt and proposes AE re-classify (or re-functionalize) fees for electric meter damage, broken seals, after-hours connections, and new service connections as customer-related, rather than distribution.[307] The ICA also proposes a different allocation method for smart meters and new service connections. These issues are discussed at Section III.D Class Allocation.

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[301] AE Ex. 1 at 53.
[302] AE Ex. 1 at 53-54.
[303] AE Ex. 1 at 53.
[304] AE Ex. 1 at 54.
[305] AE Ex. 1 at 54.
[306] AE Ex. 1 at 54-55.
[307] ICA Ex. 3 at 37-38.

a. 311 Call Center

AE explains the 311 Call Center is a communication system that connects users with various city departments, including AE.[308] AE concludes that the call volume best correlates with the number of customers, and that the call volume drives the cost of the call center.[309] Resultingly, AE proposes the costs and expenses related to the 311 Call Center be functionalized according to customers, and costs allocated to each rate class based on the number of customers in the class, with each customer in the class receiving an equal allocation.

The IHE acknowledges that while several participants disagree with AE's proposed cost allocation methodology, discussed in detail at Section III.D Class Allocation, no participant takes issue with AE's functionalization of the costs related to the 311 Call Center. Accordingly, the IHE recommends approval of AE's proposed functionalization of the 311 Call Center according to customer class. The IHE recommends the costs of the 311 Call Center be allocated consistent with the method discussed at Section III.D Class Allocation.

b. Bad Debt

As an MOU, AE must recover all costs of doing business from its customers.[310] AE takes the position that, because uncollectible expenses are more customer-driven, rather than driven by energy or demand, the associated costs are more appropriately deemed functions of customer service, as opposed to functions related to production, transmission, or distribution.[311] AE explains that the customer function, which encompasses customer accounting, including billing and collections, is most consistent with cost causation for the bad debt, because uncollectible expense is caused by customers who fail to pay.[312] AE states it uses a direct assignment to allocate uncollectible expense (or bad debt) to customer classes.[313]

The ICA argues that, instead of using a direct assignment, AE should use revenue as the basis for the allocation of this expense.[314] The ICA claims that AE's bad debt expense should not be functionalized to customer service because an uncollectible expense is a system cost of doing business, and the NARUC CAM specifically excludes bad debt from the customer classification.[315]

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[308] AE Ex. 5 at 6.
[309] AE Ex. 5 at 7.
[310] AE Ex. 1 at 501 (see definition of "base rate"), 720 (see definition of "municipally owned utility").
[311] AE Ex. 6 at 8-9; AE Ex. 9 at 43.
[312] AE Ex. 9 at 43.
[313] AE Ex. 6 at 8.
[314] ICA Ex. 3 at 39-42; ICA Brief at 31-32.
[315] ICA Ex. 3 at 61; AE Ex. 6 at 9.

AE disagrees that the NARUC CAM specifically excludes bad debt from the customer classification.[316] AE points out that the relevant NARUC CAM text cited by the ICA in support of its position actually 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***."[317]

The ICA also cites Commission precedent to support its recommendation, but AE argues such reliance is misplaced because the 1998 case ICA cited is outdated.[318]

AE argues that the direct assignment method is appropriate and it recognizes the varying likelihood (or risk) of uncollectible expense, depending on the customer class.[319] AE therefore concludes, based on historical experience, that direct assignment better aligns the test year cost with the customer classes that have contributed to the bad debt.[320]

The IHE agrees that uncollectible expenses are more customer-driven, rather than energy-driven or demand-driven, and the associated cost causes are more functions of customer service, as opposed to functions related to production, transmission, or distribution. Thus, the IHE recommends that bad debt be functionalized to the customer function as proposed by AE.

c. Functionalization and Allocation of Services and Meters

i. Smart Meter Allocation

AE functionalized meters and related services as distribution to align with the functionalization of costs.[321] The ICA recommends fees for electric meter damage, broken seals, after-hours connections, and new service connections be functionalized as customer-service

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[316] AE Ex. 6 at 9.

[317] AE Ex. 6 at 9; National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual (Jan. 1992) (NARUC CAM) at 102 (emphasis added).

[318] ICA Brief at 31; *Application of Entergy Gulf States, Inc. for Approval of its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Underrecovered Fuel Costs*, Docket No. 16705, Second Order on Rehearing at Finding of Fact No. 231 (Oct. 14, 1998).

[319] AE Ex. 6 at 9.

[320] AE Ex. 6 at 9.

[321] AE Ex. 6 at 7.

functions, rather than as distribution.[322] AE responds that, although the meters and services are distribution assets, it sub-functionalizes meters services as customer-related – under the distribution function.[323] Specifically, AE functionalized meters as distribution, but this sub-category of costs and revenues is classified as customer-related and allocated to customer classes based on a weighted customer meter allocator.[324] AE also classified revenues for meter damage, broken seals, and after-hours connections as customer-related within the distribution function.[325]

The IHE finds that AE's classification of meters and revenues for meter damage, broken seals, and after-hours connections as customer-related within the distribution function is reasonable. The IHE is not persuaded that the ICA offers a better approach on this issue.

The ICA also proposed a different allocation method for meter costs. This issue is addressed in Section III.D.

ii. Services

AE, however, acknowledges and agrees with ICA's recommendation that new service connection revenues be functionalized to the customer, rather than demand.[326] AE notes that the new service connection fee is a flat fee per new connection, and the fee is independent of the demands a customer places on the electric system.[327] AE represents that making this change reduces the identified customer-related costs.[328]

The IHE agrees with ICA that services are appropriately functionalized as customer-related. Accordingly, the IHE recommends functionalizing services as customer-related, consistent with ICA's recommendation and AE's agreement.

The ICA's proposed cost allocation of meter-related costs, including smart meters, is discussed below in Section III.D.

C. Classification

Classification, or sub-functionalization, further separates the functionalized costs simultaneously into (1) cost classifications based on the general type of activity that causes the costs, and (2) sub-functions which are sub-divisions within each business function.[329] AE explains

[322] ICA Ex. 3 at 37-38.
[323] AE Ex. 6 at 7.
[324] AE Ex. 6 at 7.
[325] AE Ex. 6 at 7.
[326] ICA Ex. 3 at 37-38; AE Ex. 6 at 8.
[327] AE Ex. 6 at 8.
[328] AE Ex. 6 at 8.
[329] AE Ex. 1 at 48.

that most cost classifications are demand-related, customer-related, and energy-related.[330] Some costs are revenue-related, measured by revenue requirement, while some can be directly assigned to a customer or customer class.[331]

1. Demand-Related Costs

Demand (or capacity) costs are those costs associated with designing, installing, and operating the system to meet maximum hourly electric load requirements.[332] AE notes that demand-related costs are considered fixed costs because they do not vary with consumption.[333] Demand-related costs are associated with the production, transmission, and distribution systems and represent the costs of meeting the overall electric demand on AE's system.[334] Demand-related costs are assigned to each customer class based on the class contribution to system demand. For cost allocation purposes, class demands are measured at different points on the system and also at different times for different functions.

- For the production function, AE is concerned with making generation available during the ERCOT system peak throughout the year; therefore, to allocate demand costs to each customer class, AE calculates each customer class's contribution to ERCOT peak demand in each month of the year.[335] AE argues this is the most appropriate methodology for AE, as described in Section III.D, below.
- For the transmission function, the Commission has determined that the transmission grid is built to meet the peak demands during the summer months of June, July, August, and September; therefore, class demands coincident with ERCOT system peak summer demands, known as "4CP demands," are used to allocate transmission costs to each customer class.[336]
- The distribution function is concerned with meeting localized demands; therefore, class maximum demands are used to allocate distribution costs.[337] This is the most appropriate methodology for AE, as described in Section III.D, below.
- For individual customers, AE is concerned with the maximum demand that the specific customer places on the system. These demands are significant cost drivers for AE's capital expenses, including debt.[338]

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[330] AE Ex. 1 at 56-57.
[331] AE Ex. 1 at 58.
[332] AE Ex. 1 at 48.
[333] AE Ex. 1 at 56.
[334] AE Ex. 1 at 56.
[335] AE Ex. 1 at 56.
[336] AE Ex. 1 at 56-57.
[337] AE Ex. 1 at 57.
[338] AE Ex. 1 at 57.

2. Energy-Related Costs

Energy-related costs are expenses that vary with electricity consumption.[339] Costs related to supply are classified as energy-related to the extent they vary with the amount of electricity purchased or generated by the utility for its customers. AE notes that the most significant energy-related costs it incurs are fuel and energy market costs.[340] The costs of coal, natural gas, renewable contracts, nuclear fuel expenses, and purchases from the ERCOT wholesale market are all considered energy-related costs.[341] AE does not recover any energy-related costs in base rates (although AE does recover some fixed costs through energy charges).[342]

Classification of Production Non-Fuel O&M Expense as Demand

AE classifies all production base rate O&M expense as demand-related.[343] The ICA opposes this and recommends that AE adopt the NARUC Cost Allocation Manual (CAM)[344] approach to classify production O&M costs, which would classify a significant portion of production non-fuel O&M expense as energy-related.[345] The ICA posits that it is unaware of another bundled electric utility which owns multiple generating units that applies a 100% demand classification to these expenses.[346] The ICA notes that the NARUC CAM specifies a methodology for defining the demand and energy portion of each account. The ICA argues this is a reasonable convention for evaluating the classification of generation O&M expense.[347] For example, the ICA notes that, like most mechanical devices, the frequency of maintenance for production facilities is generally a function of the wear and tear associated with the duration of operating the facilities. The ICA contends it is not reasonable to assign causal responsibility for maintenance costs solely to peak hours during the year.[348] Finally, the ICA notes that this method is an accepted convention and has been adopted by the PUC in the past.[349]

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339 AE Ex. 1 at 57.
340 AE Ex. 1 at 57.
341 AE Ex. 1 at 57.
342 AE Ex. 1 at 57. Energy-related costs are recovered through the PSA, which is not affected by any adjustment to base rates.
343 AE classifies Nacogdoches Plant O&M expense as Energy, but includes these costs in the PSA.
344 NARUC CAM.
345 ICA Brief at 19-20.
346 The ICA notes that, among current bundled electric utilities in Texas, SWEPCO, SPS, and El Paso Electric Co. (EPE) classify a significant portion of production non-fuel O&M expense as energy-related.
347 NARUC CAM at 35-41, Table labeled "Exhibit 4-1."
348 ICA Ex. 3 at 32.
349 ICA Ex. 3 at 30-32.

AE argues that, given its current business environment, the ICA's recommendation is inappropriate. AE notes that 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.[350] AE points out that the guidelines were developed well before the deregulation of wholesale power markets. AE argues that the 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.[351]

AE explains that significant changes in the ERCOT power market have impacted the industry's business operations.[352] Similar to other Texas utilities, AE is operating in a competitive wholesale power market, working to achieve aggressive conservation and demand response goals, responding to increased interest in distributed generation options by customers, and dealing with long-term, low-load growth projections.[353] AE argues that all of these factors create load uncertainty, energy volatility, and revenue instability. AE posits that fixed cost recovery is no longer certain in the wholesale power market or through rates.[354] 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.

AE argues that its classification of production variable costs aligns with the economics of generation dispatch in ERCOT and reflects costs AE will recover from the market.[355] Depending upon market prices, other costs above and beyond these short-run variable costs may be recovered, but AE points out that such recovery is not guaranteed. As a result, AE's customers are ultimately responsible for some or all of the generation costs above short-run variable costs.[356] According to AE, if 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 states that its generation assets must be in a state of "readiness to serve," or operationally available, when market conditions provide economic

[350] AE Ex. 8 at 18.
[351] AE Ex. 8 at 18.
[352] AE Ex. 8 at 18.
[353] AE Ex. 8 at 18-19.
[354] AE Ex. 8 at 19.
[355] AE Ex. 8 at 20.
[356] AE Ex. 8 at 19.

opportunities for dispatch on short notice.[357] With this approach, AE generation resources can effectively act as a financial hedge and protect customers from costly market events.[358]

Based on AE's reasoning above, the IHE agrees with AE that these O&M expenses are properly classified as demand related costs in the nodal market.[359] As AE states, non-fuel related O&M expenses ensure high availability and capacity-on-demand for all AE generation resources, which is prudent in the ERCOT market.[360]

3. Customer-Related Costs

Customer-related costs are expenses that reflect the minimum amount of fixed costs that the utility needs to supply for customers to access the utility system.[361] These are the cost of meters, meter reading, meter maintenance, and billing.[362] These costs vary with the addition or subtraction of customers, not usage.[363] AE argues that these are properly considered customer-related costs rather than demand-related costs or energy-related costs.

The ICA recommended that fees for electric meter damage, broken seals, after-hours connections, and new service connections be functionalized to customer, rather than the distribution function.[364] As discussed in Section III.B.4.c, above, AE contends it has already correctly addressed the customer-related nature of these revenues in its proposal and no adjustment is appropriate. The IHE recommends that the ICA's recommendation to increase the amount of fees classified as customer-related by $2.8 million is unnecessary and should be rejected.

The ICA also recommended that new service connection revenues should be functionalized to customer, rather than demand.[365] As discussed in Section III.B.4.c, above, AE agrees with the ICA's proposal on this issue.

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[357] AE Ex. 8 at 19-20.
[358] AE Ex. 8 at 20.
[359] AE Ex. 8 at 20. AE notes that, during the 2016 Base Rate Review, the IHE found that AE dispatches its production units to meet market demand and is no longer based on the paradigm in the NARUC CAM. The IHE agreed that 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. Austin Energy's 2016 Rate Review, *Impartial Hearing Examiner's Report* at 149 (Jul. 15, 2016) (2016 IHE Report).
[360] AE Ex. 8 at 20.
[361] AE Ex. 1 at 57.
[362] AE Ex. 1 at 57.
[363] AE Ex. 1 at 57.
[364] ICA Ex. 3 at 37-38; ICA Brief at 20.
[365] ICA Ex. 3 at 37-38; ICA Brief at 20.

The ICA also recommended a change to the way services are classified and allocated to customer classes.[366] The ICA proposes that services be classified as customer-related, rather than demand-related, and that this cost should be allocated to customer classes based on a weighted allocator comprised of 50 percent 12 Non-Coincident Peak (NCP) and 50 percent customer count.[367]

AE agrees that it is not unusual for services to be allocated based on a weighted customer allocation. AE views services as demand-related, however, because the cost varies with a customer's individual demand.[368] As a result, AE allocated services to customer classes based on sum of maximum demand (SMD) excluding primary and transmission voltage customers, but not 12 NCP as claimed by the ICA.[369] AE does not argue that the ICA's proposal is inappropriate. Instead, AE contends that the use of SMD as the selected allocator for services is fair and reasonable because this allocator is derived through a combination of customer (meters) and demand. SMD is the sum of customer maximum demands at the meter which is, in fact, a weighted customer allocator that reflects both customer count and demand.[370]

The IHE agrees with AE that SMD is an appropriate method to allocate services to customer class. As noted by AE, there is little practical difference between the ICA's proposed weighted allocator of 50 percent 12 NCP and 50 percent customer count, because it yields a virtually identical outcome for residential customers as the allocator selected by AE.[371]

4. Revenue-Related Costs

Revenue-related costs are costs that vary with the amount of revenue generated by the utility.[372] No participant took issue with AE's classification of revenue-related costs.

5. Direct Assignments

Costs that can be readily attributed to a particular customer or customer class are directly assigned to that customer or class.[373] Some participants took issue with AE's use of direct assignment to allocate Uncollectible Expense to customer classes, which is discussed below in Section III.D.6.

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[366] ICA Ex. 3 at 45-46.
[367] ICA Ex. 3 at 45-46.
[368] AE Ex. 6 at 11.
[369] AE Ex. 6 at 11.
[370] AE Ex. 6 at 11.
[371] AE Ex. 6 at 11.
[372] AE Ex. 1 at 58.
[373] AE Ex. 1 at 58.

6. A&G Expense and Indirect Costs

The ICA disagrees with AE's classification of administrative and general (A&G) expenses, specifically related to FERC Account 920, A&G Salaries, and FERC Account 930, Miscellaneous General Expenses.[374] The ICA disagrees with AE's classification of FERC Account 920 and 930 expenses, claiming that none of the potential indirect methods are strongly related in a causal sense to the underlying expenses in these accounts. According to the ICA, AE's classification of Account 920 and 930 expenses artificially inflates customer costs.[375]

The ICA notes that, as a matter of accounting definition, FERC Account 920 contains salaries and wages, which cannot be attributed to any particular function of the utility. Examples of typical expenses include the utility's chief executive, general utility officers, the treasury and finance departments, the human resources department, strategic planning, and budgeting.[376] The ICA argues that FERC Account 930 contains little if any labor cost, but instead aggregates a multitude of miscellaneous expenses from all functions of the utility. The ICA explains that both FERC Accounts 920 and 930 are classified to functions based on an indirect allocator based on payroll within each function. The ICA asserts there is no objective economic rationale for selecting particular classification factors to assign FERC Accounts 920 and 930.[377]

AE first addresses the ICA's recommendation that the functionalization of FERC Account 920 expenses be altered so that more of these expenses would be assigned to the production function. AE argues that its use of labor to functionalize the portion of FERC Account 920 expenses that were not directly assigned to the production function is consistent with the NARUC CAM's[378] treatment of this expense.[379] AE argues that the nature of the expenses in FERC Account 920 (such as executive management, accounting, finance, human resources, planning, budgeting, etc.) are most appropriately affiliated with AE's workforce.[380]

AE points out that the production function direct assignment is associated with expenses related to operations at the South Texas Project (STP) and FPP.[381] Given that AE is able to directly assign this proportion of the overall FERC Account 920 expenses to production, AE argues it is

[374] ICA Brief at 21-22.
[375] ICA Ex. 3 at 35-36.
[376] ICA Ex. 3 at 33.
[377] ICA Ex. 3 at 33.
[378] NARUC CAM at 35.
[379] AE Ex. 6 at 5.
[380] AE Ex. 6 at 6.
[381] AE Ex. 6 at 5.

appropriate to do so. AE posits that the remainder of FERC Account 920 expenses are correctly functionalized based on AE's labor costs, which exclude labor expenses at STP and FPP because AE employees do not operate or manage these generation units.[382] As a result, AE claims that it would be inappropriate to include an estimate of labor costs at STP and FPP in the labor allocator used for functionalization of this expense.[383] This would have the outcome of ignoring a direct assignment of a portion of this expense in favor of a more general allocation. AE argues that, when direct assignments are practical, as in this case, they should be favored.[384]

For FERC Account 930, AE disagrees with ICA's recommendation to replace the payroll method with non-fuel O&M factors. AE asserts that the ICA's claim that Account 930 "includes virtually no payroll expense, further confirming that a payroll classification is inappropriate"[385] is misleading. Although AE agrees with the ICA that less than one percent of the FERC Account 930 expenses are composed of AE's employee labor, many of the expenses in FERC Account 930 are related to supporting AE's employees, such as Human Resources, Information Technology, and Corporate Support Services.[386] Similar to FERC Account 920 expenses, AE argues it is appropriate to functionalize expenses that were not directly assigned to the production function based on labor, as AE has done. This is consistent with treatment in the NARUC CAM.[387] Therefore, the ICA's recommendations related to FERC Account 930 should be rejected.

The IHE agrees that AE's classification of expenses in FERC Accounts 920 and 930 is reasonable and should be adopted. The IHE is persuaded that the nature of the expenses in FERC Account 920 (such as executive management, accounting, finance, human resources, planning, budgeting, etc.) are most appropriately affiliated with AE's workforce. The IHE is also persuaded that, because AE's employees do not operate STP or FPP, it would be inappropriate to include an estimate of labor costs at STP and FPP in the labor allocator used for functionalization of this expense. Instead, STP and FPP expenses should be directly assigned to production. The IHE is also persuaded that it is inappropriate to replace the payroll method with non-fuel O&M factors for FERC Account 930 expenses that are related to supporting AE's employees, such as Human Resources, Information Technology, and Corporate Support Services.

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[382] AE Ex. 6 at 5-6.
[383] AE Ex. 6 at 6.
[384] AE Ex. 6 at 6.
[385] ICA Ex. 3 at 33-37; ICA Brief at 22.
[386] AE Ex. 6 at 6-7.
[387] AE Ex. 6 at 7.

7. Cost Classification Results

The numeric results of AE's cost classification are included in Table 5-E of AE's RFP, with more detailed results in Schedule G and associated workpapers.[388]

D. Class Allocation

Class Allocation attributes the functionalized and classified costs to individual customer classes based on cost causation.[389] Class allocation factors are developed for demand-related, energy-related, and customer-related costs.[390] AE then applies these factors to distribute classified costs to each customer class according to the class's contribution to that cost.[391] AE posits that its proposed allocation factors were developed to be consistent with each cost classification methodology applied. AE's allocated COS Study is consistent with cost-causation principles and should be adopted.

1. Demand-Related Costs

Demand-related costs are expenses that are driven by demand on the system.[392] AE argues that, within each function, the allocation of demand-related costs to each customer class was based on accepted industry practices that seek to assign costs to each class in alignment with the way costs are incurred by the utility.[393] As discussed below, the ICA, NXP, and TIEC all recommended changes to AE's proposed demand cost allocation methods.

a. Production-Demand

Production-demand related costs are the costs associated with building and maintaining AE's generation fleet or contracting for outside generation capacity.[394] TIEC explains that the methodology used to allocate production-demand costs should reflect each customer class's contribution to AE's need for additional production capacity.

AE proposes to use the ERCOT 12 Coincident Peak (ERCOT 12CP or 12CP) methodology to allocate the cost of generation.[395] The ICA, NXP, and TIEC advocate instead for adoption of different production demand methods. The ICA recommends the Baseload-Intermediate-Peak

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388 AE Ex. 1 at 58.
389 AE Ex. 1 at 48.
390 AE Ex. 1 at 59.
391 AE Ex. 1 at 59.
392 AE Ex. 1 at 60.
393 AE Ex. 1 at 60.
394 TIEC Ex. 1 at 22.
395 AE Ex. 1 at 60.

(BIP) methodology. NXP and TIEC recommend the Average & Excess 4CP (A&E 4CP or 4CP) allocation methodology.[396]

According to AE, the ERCOT 12CP methodology better aligns the relationship between the costs and the benefits that accrue from owning and operating AE's fleet of generation in the ERCOT market, where benefits and some of the costs flow back to AE's customers through the PSA.[397] AE argues that this methodology allocates production expenditures to customer classes based on each class's contribution at the time of the ERCOT system peak demand during each of the twelve calendar months.[398] AE posits that applying this methodology recognizes that all of AE's customers benefit from AE's generation fleet year-round, and balances the interests of residential and commercial customers.

IHE Recommendation Summary

One of AE's chief complaints about the BIP and A&E 4CP allocation methodologies is that they shift costs to other customer classes whose interests the ICA, NXP, and TIEC do not represent. Regarding the BIP method, the IHE agrees with AE that BIP is a mis-match for how energy is dispatched into the ERCOT market. The IHE notes that AE and TIEC agree that BIP "is contrary to cost-causation and is unsupported by precedent[.]"[399] AE and NXP also agree that BIP "simply does not reflect cost causation and would result in a disparate impact on the majority of AE's customer classes."[400]

The IHE agrees with AE, TIEC, and NXP that the BIP methodology proposed by the ICA should not be adopted. The ICA has made reasonable arguments in favor of the the BIP method, but has failed to convince the IHE that it is superior to AE's proposed 12CP method. This is in part because the ICA's focus on generation types and energy use is inconsistent with how resources are dispatched and how energy is used in the ERCOT market. The IHE recommends that the ICA's proposal to replace AE's 12CP approach with the BIP method be rejected.

Regarding NXP and TIEC's proposed A& 4CP methodology, the IHE recommends retaining AE's ERCOT 12CP methodology. NXP and TIEC focus on summer peaks in demand on ERCOT's system. AE, however, focuses on peaks in ERCOT's market prices throughout the year.

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396 TIEC identifies this approach as the "Average and Excess Demand – Four Coincident Peak" (AED-4CP) methodology. TIEC Brief at 15; *see also* NXP Ex. 1 at 17-18; TIEC Ex. 1 at 23-26.
397 AE Ex. 1 at 60-61.
398 AE Ex. 1 at 61.
399 AE Brief at 46; TIEC Brief at 23.
400 AE Brief at 46; NXP Brief at 31.

The ICA criticizes the industrials' proposed 4CP methods, arguing they do not effectively recognize annual energy use.[401]

As explained below, the IHE finds that AE's 12CP methodology is reasonable because it recognizes that, even if demand normally peaks during the four summer months in a given year, non-summer wholesale prices in ERCOT may approach and could even exceed summer wholesale prices.

ICA's BIP Method Proposal

The ICA recommends replacing AE's 12CP allocation method with the BIP allocation method, which separates production costs into generation serving base, intermediate, and peak time periods and develops different class allocation factors for each component.[402] BIP is based on the premise that baseload, intermediate, and peaking generation technologies and fuel types are incurred primarily to serve each of those time periods, respectively.[403] The ICA notes that the BIP method is an accepted production allocation method in both the NARUC CAM and the RAP CAM.

First, the ICA distinguishes AE from other investor-owned electric utilities in Texas because it is a bundled utility operating in ERCOT.[404] The ICA notes that AE's 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.[405]

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.[406] The ICA understands that AE can go to the market to meet its hourly load requirements, even if it

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[401] ICA Ex. 3 at 24. ICA Ex. 4 at 6-7.
[402] ICA Ex. 3 at 20-30.
[403] ICA Ex. 3 at 25.
[404] The ICA explains that bundled investor-owned electric utilities in Texas (EPE, SPS, SWEPCO, ETI) operate in reliability regions other than ERCOT. The ERCOT market structure differs from those regional market structures faced by other bundled investor-owned utilities, which the ICA contends confirms the need for a different production allocation applied to AE. ICA Ex. 4 at 4-5.
[405] ICA Ex. 3 at 21.
[406] ICA Ex. 3 at 19-20.

has owned generation that is subject to outage or unavailability.[407] 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).

ICA witness Johnson developed two variants of the BIP methodology which he contends recognize the specific characteristics of AE's generation investment.[408] As part of the process, Mr. Johnson estimated relative margins earned by the baseload, intermediate, and peak plants in the ERCOT market, which the ICA claims demonstrates that the plants' profits in the ERCOT market produce results consistent with the primary BIP method. The ICA argues that this exercise proves the consistency of BIP with AE's participation in ERCOT and shows that the two approaches to BIP produce closely similar class allocation results.[409] As a result, the ICA contends that BIP allocation is consistent with the ERCOT market structure.

AE responds that the ICA's proposed allocation method is not relevant to the ERCOT nodal market, where generation units are economically dispatched into the market and not dispatched to serve AE's own hourly load requirements.[410] AE contends that generation resource terms such as "baseload," "intermediate," and "peaking," which are used to serve *a utility's* load, no longer have traditional meanings in ERCOT due to the structure of the ERCOT market.[411]

AE argues that the fundamental flaw with the BIP method is that it assumes that a resource, like a baseload unit, will be dispatched to serve load given the load profile and resource planning needs of *the individual utility that owns the generation*.[412] Instead, AE explains that these assets must perform when dispatched into the ERCOT market to provide value, therefore *asset availability and associated capacity are critical*. In the ERCOT market, all generating units monetize their capacity value through *the market clearing price*. AE points out that the BIP method ignores both by assigning zero capacity value to FPP and STP baseload units and assumes that these units will be dispatched into the market *at any price*.

Consistent with this criticism, AE notes that the BIP method classifies costs based on the demand and energy needs of the system *regardless of cost*. The ICA agrees with the first part of AE's characterization, because the ICA argues the dual importance of demand and energy in

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[407] ICA Ex. 3 at 22-23.
[408] ICA Ex. 3 at 24-25.
[409] ICA Ex. 3 at 27-29; Schedule CJ-1.
[410] AE Ex. 8 at 6.
[411] AE Ex. 8 at 6.
[412] AE Ex. 8 at 7.

developing production demand allocation methods is recognized in the NARUC CAM.[413] Specifically, the ICA claims that AE's 12CP method of production plant allocation is deficient because it fails to recognize the impact of *energy use* on cost causation. The ICA also argues that the other peak demand methods (including Average & Excess Demand) proposed by industrial intervenors do not effectively recognize annual energy use.[414]

AE responds that the BIP method classifies a significant portion of production-demand costs – 83.5 percent, as energy-related, and allocates these costs to the various rate classes on the basis of energy.[415] As a result, AE argues that the BIP method shifts fixed cost recovery from low load factor residential customers to high load factor commercial and industrial customers. AE explains that the BIP method severely understates the capacity value of low-cost generation resources that are often called upon to serve ERCOT load. Further, the effectiveness of the physical hedge provided by the generation fleet is a function of available capacity to offset AE's load requirements.[416] As a result, AE contends that fixed production costs are most appropriately associated with AE's peak load requirements, not energy.[417]

AE argues that the BIP method is simply inappropriate for how AE dispatches its generation in the ERCOT market. AE criticizes the underlying premise of the BIP method, which is production stacking, because it is aimed at baseload, intermediate, and peaking units to be dispatched to meet AE's load.[418] Similarly, AE notes that, despite Mr. Johnson's conclusions that the two approaches to BIP produce closely similar class allocation results to the ERCOT market,[419] his analysis and calculations are constructed to attempt to match specific AE loads with specific AE generating resources. AE reiterates that, in ERCOT, generation assets are dispatched based on market needs and price competitiveness *with price being the primary factor* under uncongested circumstances.[420] Within ERCOT, higher capacity factors of AE's coal (i.e. FPP) and nuclear (i.e. STP) units cited by ICA witness Johnson are not the result of baseload units serving load, but

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413 NARUC Electric Utility Cost Allocation Manual at 49.
414 ICA Ex. 3 at 24; ICA Ex. 4 at 6-7.
415 TIEC Ex. 2 at 8.
416 AE Ex. 8 at 8.
417 AE Ex. 8 at 8.
418 AE Ex. 8 at 6.
419 ICA Ex. 3 at 27-29; Schedule CJ-1.
420 AE Ex. 8 at 7-8.

rather a recognition that these resources are low-cost market resources and are often called on to serve the market.[421]

IHE Conclusions Regarding 12CP versus BIP Method

The IHE agrees with AE that the 12CP method is a more appropriate methodology for AE's participation in the ERCOT market than ICA's proposed BIP method. From a practical perspective, despite Mr. Johnson's calculations, the IHE is simply not convinced that the BIP method is superior to the 12CP approach within ERCOT. The fact that the BIP method is recognized in the NARUC CAM does not lend it additional weight, because it is unclear that, in recognizing the BIP method, the NARUC manual takes the ERCOT market into account.[422]

The ICA has not persuaded the IHE that the BIP method's focus on baseload, intermediate, and peaking is necessary in ERCOT. As explained by AE, the bids from generation resources dictate the dispatch of generation units in ERCOT given market conditions.[423] Because of market conditions, with the exception of STP, AE cycles all generation units within the limits of the resource technology.[424] AE's generation portfolio is dispatched in the market for the financial benefit of all AE customers.[425] As a result, the IHE agrees with AE that categorizing units as "baseload," "intermediate," and "peaking," lacks relevance in the ERCOT market.[426]

Finally, the IHE shares AE's concern that the BIP allocation method would shift costs of the most capital-intensive resources to larger commercial classes and away from the residential class. AE has shown that this is not an appropriate way to distribute production related costs because AE *no longer serves its own load with its resources*. As noted by AE, the ICA recommended the BIP methodology in the 2016 Base Rate Review, and the IHE recommended against it because it "ignores the reality of the market in which Austin Energy operates" and places too much emphasis on the market paradigm of a fully integrated utility in the non-ERCOT service areas in Texas.[427] The current IHE agrees and recommends that the ICA's recommendation to replace AE's 12CP method with the BIP method be rejected.

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[421] AE Ex. 8 at 8.
[422] AE represents that it is not aware of any utilities in Texas using the BIP method, and the PUC has not approved the BIP method in over 20 years. AE Brief at 42. The industrial consumers also make this point. NXP Brief at 18.
[423] AE Ex. 8 at 10.
[424] AE Ex. 8 at 10.
[425] AE Ex. 8 at 10.
[426] AE Ex. 8 at 6.
[427] AE Ex. 8 at 9; 2016 IHE Report at 36.

TIEC's and NXP's Proposed 4CP Method

NXP and TIEC recommend use of the A&E 4CP allocation method,[428] which uses a single coincident peak system load factor in AE's demand for each of the four summer months.[429] NXP explains that the A&E 4CP methodology considers both average demands and peak demands of AE's customer classes. The average demand is usually determined using customer class energy usage, and the excess demand is typically determined using the customer class critical monthly CP demands.[430] According to the industrials, the use of the four summer month CP demands reflects the importance of AE's summer peaking system.[431]

The industrials explain that for production-demand related costs, following cost causation requires analyzing the utility's load characteristics, which determine the amount of capacity required to meet expected demand.[432] TIEC and NXP argue that the A&E 4CP method is appropriate for summer peaking utilities like AE, because the primary driver of production demand costs is maintaining sufficient capacity to serve load during the summer peaks.[433] TIEC contends that a summer peaking utility's production-demand costs are driven by the need for adequate capacity at the summer peaks and not by lower demands at other times of the year.[434] Nevertheless, TIEC notes that A&E 4CP accurately reflects cost causation because it recognizes that a utility's generation fleet must have sufficient load-following generation to meet peak demand, but must also include sufficient baseload capacity to meet average demand at the lowest overall cost.[435]

TIEC and NXP point out that AE is a summer peaking utility in terms of demand, which is to be expected as ERCOT is predominately a summer-peaking system.[436] TIEC witness Pollock provided the following table, which plots AE's monthly system peak demands as a percentage of the annual system peak for the years 2017 through 2021:[437]

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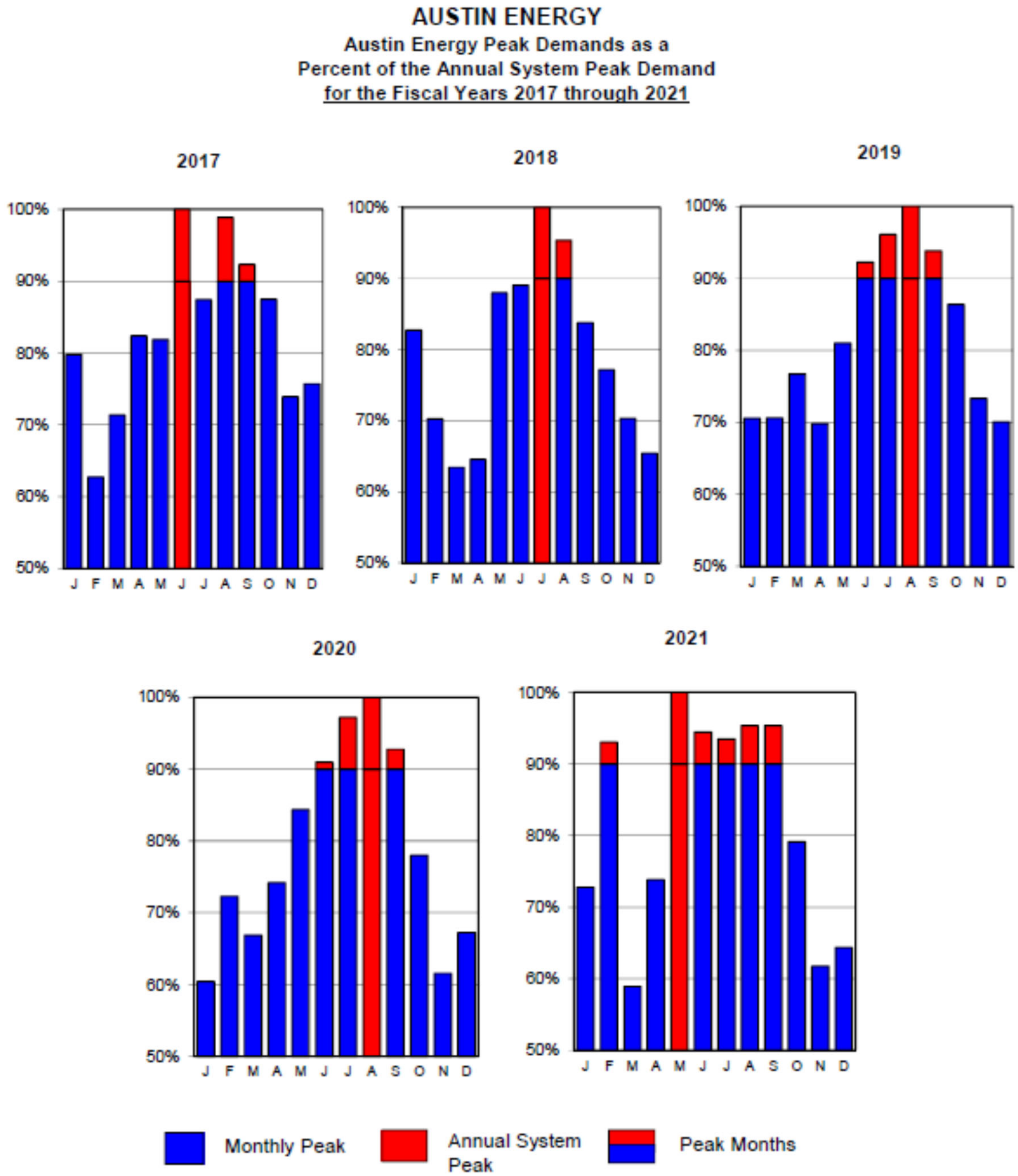
[428] Because NXP and TIEC are essentially aligned on this issue, the IHE uses the term "industrials" for both NXP and TIEC.
[429] As noted in Mr. Pollock's testimony, the PUC has consistently determined that when using an AED-4CP allocation, the system load factor should be calculated by using the single annual coincident peak, rather than the average of four coincident peaks. As a result, Mr. Pollock used a single CP system load factor in his AED-4CP calculation, which TIEC proposes should be adopted in this case. TIEC Ex. 1 at 26, n.24.
[430] NXP Ex. 1 at 18.
[431] NXP Ex. 1 at 18.
[432] TIEC Ex. 1 at 19.
[433] TIEC Ex. 1 at 20; NXP Ex. 1 at 16, 25.
[434] TIEC Ex. 1 at 20.
[435] NXP Ex. 1 at 18; TIEC Ex. 2 at 3.
[436] NXP Ex. 1 at 27, 78; TIEC Ex. 1 at 20.
[437] TIEC Ex. 1 at 20; Ex. JP-3 at 1; *see also* NXP Ex. 1 at 27, 78; NXP Brief at 21.



TIEC notes that AE expects to remain a summer peaking utility in the future[438] and admits that "[t]hroughout its ten-year planning horizon, AE projects that it will still peak in the summers, including within the next five years."[439] The industrials add that the same is expected in ERCOT more generally.[440] NXP notes there is a close relationship between AE's monthly CP demand and

[438] TIEC Ex. 1 at 20.
[439] TIEC Ex. 1 at Appendix F (AE Response to TIEC 5-6).
[440] NXP Ex. 1 at 20; TIEC Ex. 1 at 20.

ERCOT's peak demand during the test year, and AE must operate its generation at greater capacity levels during the summer months as directed by ERCOT.[441]

Based on AE's summer demand peaks, the industrials argue that cost causation principles dictate that production-demand costs should be allocated to each customer class based primarily on their demand during the four summer coincident peak intervals, making appropriate the A&E 4CP methodology.[442] The industrials also note that the A&E 4CP methodology acknowledges that a utility will invest in baseload generation if it is expected to have a high capacity factor, meaning it will run frequently—which is typically driven by average demand/energy. As a result, the industrials argue the A&E 4CP method appropriately captures the role of both year-round energy usage and peak demand in driving new generation investment.[443]

TIEC points out that the PUC has consistently used A&E 4CP to allocate production demand costs for all four of the vertically-integrated utilities it regulates.[444] Other nearby states with summer peaks, including New Mexico and Colorado, have also approved A&E 4CP to allocate production demand costs.[445]

The industrials note that AE supported an A&E 4CP allocation for production-demand costs as recently as its 2012 rate review.[446] The industrials also point out that the City adopted an ordinance endorsing the A&E 4CP methodology.[447]

The industrials contend that AE's 12CP approach is a mis-match for a utility with summer demand peaks.[448] TIEC notes that AE witness Burnham admitted that, if a utility has sufficient capacity to meet its single peak demand for the year, the utility's system will necessarily be able to meet demand in the remaining months.[449] According to the industrials, the A&E 4CP allocation already takes into account that AE's generation operates and provides value throughout the year, and a 12CP allocation gives undue weight to non-peak demand periods in terms of driving additional investment.

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[441] NXP Ex. 1 at 22, Graph 2.
[442] NXP Ex. 1 at 20.
[443] TIEC Brief at 18.
[444] TIEC Ex. 1 at 23 and Appendix D; Tr. (July 13) at 110:27-111:16 (Murphy Cr.).
[445] TIEC Ex. 1 (Pollock Dir.) at 24.
[446] TIEC Ex. 1 (Pollock Dir.) at 22; Tr. (July 13) at 115:39-42 (Burnham Cr.).
[447] NXP Ex. 1 at 17; Tr. at 73: 8-13 (Jul. 15) (Burnham Cross); NXP Ex. 3 (COA Ordinance 20120607-055) at Bates 000003 ("The Council adopts as policy the use of the A&E 4CP methodology to allocate production demand costs among customer rate classes.").
[448] TIEC Brief at 19.
[449] Tr. (July 13) at 114:22-28 (Burnham Cr.).

AE's Position on the 12CP versus 4CP Method

AE argues that the 12CP allocation approach is more equitable than the A&E 4CP method for production demand costs. AE notes that the A&E 4CP method is focused on peak demand, while AE's 12CP method is focused on peaks in the market price of energy throughout the year. AE criticizes the A&E 4CP method because the 4CP allocation shifts costs from large commercial and industrial customers to the residential class by approximately 5.2 percent.[450]

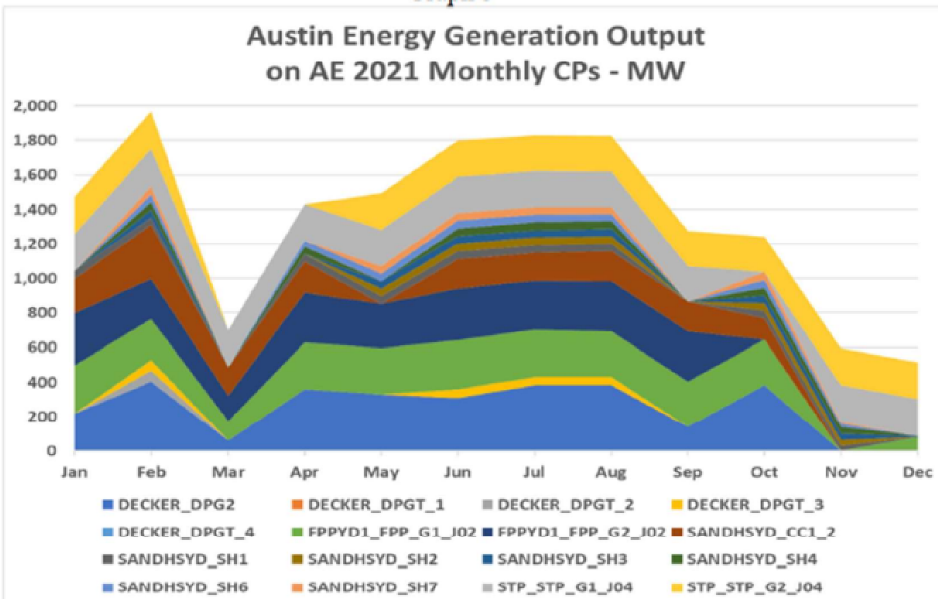
As explained above, AE's generation assets are dispatched to the ERCOT market, not to serve AE's load. AE contends that a 12CP allocation approach is superior to a 4CP approach because the 12CP recognizes the *wholesale price* hedging value provided to customers by AE's generation portfolio over a greater percentage of peak hours.[451] AE explains that market prices remain unpredictable throughout the year, not just during the summer months, so the 12CP approach recognizes benefits to AE ratepayers over a larger number of hours than the 4CP approach, including the benefit of AE's physical hedge.

AE provided the following table, which illustrates that AE's generation resources were significantly dispatched to meet ERCOT load during non-summer months, including January, February, April, May, and October of 2021:[452]

[450] AE Ex. 8 at 17.
[451] AE Ex. 8 at 14.
[452] AE Ex. 8 at 12, *citing* NXP Ex. 1 at 23.

Figure 1 – Austin Energy Generation Output

Graph 3

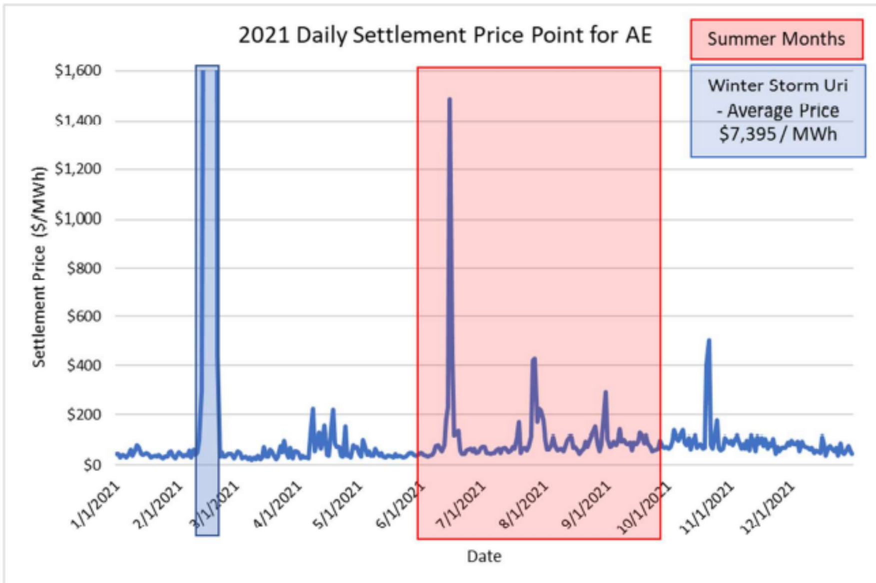


Thus, AE points out that the capacity value of AE's generation resources is realized throughout the year and is not limited to the four summer months in ERCOT. AE notes that, during Winter Storm Uri in February 2021, AE was able to provide generation when a large portion of the ERCOT market was not able to do so.[453]

AE also notes that, in 2021, there were significant increases in ERCOT market prices during periods outside of the four summer months, as indicated in Figure 2 below, which shows the peak daily market price in dollars per megawatt hour ($/MWh) for 2021 for the AE node:[454]

[453] AE Ex. 8 at 13.
[454] AE Ex. 8 at 13.

Figure 2 – 2021 Daily Settlement Point Price for Austin Energy



As illustrated, there were several days during the non-summer months, exclusive of Winter Storm Uri, which experienced an hourly price greater than \$100/MWh.[455] Thus, AE argues that that AE generation resources provide value to AE customers throughout the year.

AE contends that NXP and TIEC's proposed A&E 4CP methodology ignores how ERCOT nodal market prices impact the production costs of resources needed to meet demand, and fails to recognize that wholesale market price increases do not exclusively occur during peak demand periods of the year. AE argues that non-summer price spikes present risks against which AE must hedge its exposure. To ensure that its resources are available to provide energy when market prices are high, AE posits it must maintain its fleet throughout the year. AE notes that O&M expenses ensure high availability and capacity-on-demand for all AE generation resources and are properly classified as demand-related costs in the nodal market.[456] As a result, AE argues that it is reasonable to allocate its production costs based on a methodology that considers the impact of peak market prices throughout the year.

IHE Conclusions Regarding 12CP versus 4CP Method

The IHE recommends adoption of the 12CP allocation method instead of NXP and TIEC's proposed A&E 4CP method. As explained above, the industrials support the A&E 4CP method,

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[455] AE Ex. 8 at 13.
[456] AE Ex. 8 at 20.

arguing that it better recognizes that AE is a summer-peaking utility. The industrials, however, are focused on demand,[457] while AE is focused on the peak price intervals within ERCOT—not all of which occur during the summer months.

While TIEC and NXP offered evidence that market prices are consistently higher in the highest demand summer months, this is not always the case. It is possible that market prices during a high-demand winter storm could rival or even exceed prices during the summer. This could be due to circumstances such as less generation online, fuel scarcity, or other issues. As a result, the hedging value provided to customers by AE's generation portfolio over a greater percentage of peak hours is a reasonable and equitable approach to the allocation of production demand costs. Although an extreme example, the market prices during Winter Storm Uri illustrates AE's concerns and its year-round allocation of production costs.

The industrials have pointed out that in AE's 2012 rate case, AE supported the A&E 4CP method.[458] However, AE claims that after several years of actual data operating in the ERCOT nodal market, AE recognized that an effective capacity hedge was a key benefit to its customers in the ERCOT market year-round and not just during the summer peak demand months.[459] As a result, in AE's 2016 rate case, AE changed from the A&E 4CP demand allocator to a 12CP allocator.[460] The IHE finds that this change to 12CP has been justified. AE is a not-for-profit electric utility owned by the City. That is, AE is not focused on delivering a return to shareholders. Instead, its goal is to provide reasonably priced reliable energy at cost. AE's allocation of production demand costs based on wholesale price peaks throughout the year, instead of peaks in demand during the summer months, is appropriate.

The industrials have demonstrated that AE is a summer peaking utility in terms of demand.[461] The industrials also provided evidence that costs and hedging benefits are driven in large part during those high demand summer months—Mr. Pollock provided an exhibit showing ERCOT's highest cost intervals are aligned with the highest demand periods in the summer.[462] AE's point, however, is that in every year, some winter months may see demand rivalling summer

[457] TIEC Ex. 1 at 25-26 & n.24.
[458] TIEC Ex. 1 at 19; TIEC Ex. 9 at 21 (D. 44941, Direct Testimony of Brian Murphy excerpt); Tr. (July 13) at 111:15-16, 32 (Murphy Cr.); TIEC Ex. 13 at Bates 24-25 (D. 40627, Direct Testimony of Joseph Mancinelli excerpt).
[459] AE Ex. 8 at 15.
[460] AE Ex. 8 at 15.
[461] NXP Ex. 1 at 20; TIEC Ex. 1 at 20; Ex. JP-3 at 1.
[462] TIEC Ex. 1 at 23; Ex. JP-4 (demonstrating that the highest LMPs cluster around peak hours in the summer).

months. Looking at demand alone, AE's Figure 1 above demonstrates that in 2021 demand in January was fairly high relative to the summer months. Winter Storm Uri, as depicted in Figure 1, exceeded demand for all of the summer months.[463]

AE's focus, however, is not on demand alone, but on wholesale prices within ERCOT. AE's 12-month focused price hedging strategy is reasonable, because ". . . wholesale market price increases do not exclusively occur during peak demand periods of the year."[464] AE's use of a 12CP cost allocation method is appropriate to reflect AE's physical hedge to protect its customers against high prices throughout the year.[465]

For instance, when demand peaked during Winter Storm Uri, the wholesale price within ERCOT was so high that the actual peak is not represented in Figure 2, above. The highest 4CP peak *represented* in Figure 2 appears to be around $1,500/MWh in early July 2021. The *average* price during Winter Storm Uri during February 2021 is stated as $7,395/MWh. Importantly, however, if the February 2021 peak is set aside as an anomaly, Figure 2 clearly reflects that the next highest wholesale price after July 2021 occurred in November 2021.[466]

Finally, the IHE notes that AE's change to the 12CP allocation method was recommended by the IHE in the 2016 Base Rate Review.[467] The industrials correctly point out that the 2016 case was resolved through a black-box settlement that did not specify a particular allocation methodology.[468] The industrials also argue that the IHE's basis for AE's proposed change in allocation policy was flawed. TIEC notes that the primary reason for the IHE recommendation to adopt the 12CP method was that "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."[469] TIEC disagrees, stating that ". . . high wholesale prices occur when demand approaches available supply—i.e., during 4CP peak demand periods—so the incentive to capture high nodal pricing *still supports a peak-based allocation*."[470] The IHE finds that, while TIEC and NXP have provided evidence that the latter statement is often true, it is not true all of the time. AE's evidence shows demand approaches, and can exceed available supply,

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463 AE Ex. 8 at 13.
464 AE Brief at 45.
465 TIEC Ex. 1 at 21; Tr. (July 13) at 113:39-45 (Burnham Cr.).
466 AE Ex. 8 at 13.
467 AE Ex. 8 at 15, *citing* 2016 IHE Report at 166.
468 Tr. (July 14) at 58:8-10 (Daniel Cr.).
469 TIEC Ex. 11 at 150 (2016 Impartial Hearing Examiner's Report Excerpt).
470 TIEC Brief at 20 (emphasis in original).

resulting in high wholesale prices during non-summer months. It is reasonable for AE to be focused on this contingency. The IHE recommends that AE's ERCOT 12CP allocation method should be retained.

b. Distribution-Demand

Class NCP demand is normally used to allocate most demand-related distribution costs. AE proposes that distribution substations, poles, and conductors be allocated using the 12NCP allocator, which allocates the costs of these facilities using a 12-month average of the customer classes' monthly NCP demands for the test year.[471] AE argues that the 12NCP method recognizes that distribution facilities provide value throughout the year, and better captures the contributions of off-peak or seasonal customers whose demand may not be fully reflected in their class's peak.[472] The ICA supports AE's 12NCP allocator.[473]

NXP and TIEC[474] recommended replacing the 12NCP allocator with an annual (or highest month) 1NCP method for allocating distribution substations, poles, and conductors.[475] The industrials explain that the 1NCP methodology allocates distribution-demand costs using the annual peak demand of each rate class during the test year.[476] By using each class's highest annual demand, the industrials point out that the 1NCP methodology recognizes that distribution facilities needed to serve each class are sized to reliably serve the class's maximum demand, not some lower amount.[477] As a result, NXP and TIEC argue that this approach better tracks cost causation because it more accurately recognizes the contribution of each rate class to AE's distribution-demand costs.[478]

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471 AE Ex. 1 at 62.
472 AE Ex. 8 at 21.
473 ICA Ex. 4 at 8-9; ICA Brief at 26-29.
474 TIEC notes that TIEC and AE agree that these costs should be allocated on an NCP basis rather than a CP basis. As AE explains in the Rate Filing Package: "[d]istribution facilities such as substations that directly interconnect with the transmission system are designed to meet the aggregated customer loads in specific geographic areas. As the systems are designed to meet localized demands, the costs are most appropriately allocated by analyzing the magnitude and timing of the class peak demand, which often occurs at times different from the system peak demand. . . . The peak demand of the class, without regard to the timing of the system peak demand, is referred to as the 'non-coincident peak' demand, or NCP demand." AE Ex. 1 at 62.
475 NXP Brief at 32; TIEC Brief at 25; TIEC Ex. 1 at 31; Ex. JP-6 (1NCP class allocation factors applicable to secondary distribution costs); Ex. JP-7 (1NCP allocation factors applicable to distribution substations and other primary distribution costs).
476 TIEC Ex. 1 at 28.
477 TIEC Ex. 1 at 30.
478 TIEC Ex. 1 at 28.

The industrials further object to AE's allocation of these costs based on the average of the 12 monthly class NCP demand, because that average will necessarily be lower than the actual absolute peak demand.[479] The industrials argue that because distribution facilities are sized and built to meet the localized peak demands, it does not logically follow that AE should use a 12-month average NCP demand to allocate primary distribution plant costs.[480] To appropriately reflect cost causation, the industrials assert that a 1NCP methodology should be used for allocating primary distribution plant costs.[481]

The industrials argue that 1NCP better tracks cost because AE builds its distribution system to have sufficient capacity to reliably serve its customers at the time of maximum demand. So long as AE builds for maximum demand, it will have a system that is also capable of providing service in times of lower demand. The industrials contend that off-peak or seasonal customer demand is not what drives investment in the distribution system, instead building for peak demand is a significant cost driver for AE's capital expenses, including debt.[482] As a result, the industrials argue that AE's use of the 12NCP demand allocation methodology is at odds with the actual class peak demands that cause AE to incur most of its distribution system costs.[483]

The IHE notes that building a distribution system to meet peak demand is not in dispute in this proceeding—it is a reliability measure. AE does not deny that it built its distribution system to withstand peak usage.[484] AE acknowledges that if the distribution system were only designed to meet the 12NCP average and not the 1NCP demand, AE could experience outages and be forced to curtail customers at the time of peak usage.[485] Nor does AE disagree that the average of 12 monthly NCPs will tend to be lower than the actual NCP peak.[486] The IHE does not view reliability measures as determinative of cost allocation methods.

AE argues that the 12NCP allocator is more equitable than 1NCP.[487] This is because the 12NCP method recognizes that distribution capacity provides value to customers throughout the

[479] TIEC Ex. 1 at 27.
[480] NXP Ex. 1 at 29.
[481] NXP Ex. 1 at 29-30.
[482] AE Ex. 1 at 57.
[483] AE Ex. 1 at 57.
[484] Tr. (July 13) at 119:38-39 (Burnham Cr.) ("… the distribution system has to be built to withstand its peak usage, right? That is correct.").
[485] Tr. (July 13) at 119:38-46 (Burnham Cr.); Pollock Dir. at 27.
[486] Tr. (July 13) at 119:35-38 (Burnham Cr.).
[487] AE Ex. 8 at 21.

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 1NCP calculation.[488] AE argues a 12NCP calculation solves this problem. AE has determined as matter of policy that 12NCP will facilitate customers who are becoming increasingly interested in distributed generation options and are able to shift load and demand. From a cost allocation perspective, AE posits that certain rate classes may be able to avoid a portion of distribution demand related costs by shifting demand during NCP periods. AE argues that, if the demand measure is a single hour (the 1NCP), the ability to shift and avoid cost responsibility is easier compared to a 12NCP method.[489]

Additionally, AE notes that 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. AE argues that these variations are better represented by a 12NCP allocator, which takes into consideration the value of load diversity across the distribution system.[490]

Finally, the industrials point to numerous IOUs that use a 1NCP allocation for distribution-demand costs. The industrials note that a 1NCP allocator is also consistent with PUC precedent for both ERCOT and non-ERCOT utilities.[491] The industrials point out that in recent rate cases, TNMP's and Oncor's witnesses explained that the 1NCP method best recognizes the cost causation associated with the load of each rate class on the utility's distribution system.[492]

The IHE recommends that AE's 12NCP allocator be adopted. The IHE does not deny that a 1NCP methodology has been found reasonable for allocating distribution demand costs. However, the IHE finds more compelling the fact that other MOUs in Texas, such as Bryan Texas Utilities and Greenville Electric Utilities, use a 12NCP method to allocate distribution costs.[493]

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[488] AE Ex. 8 at 21.
[489] AE Ex. 8 at 21.
[490] AE Ex. 8 at 23.
[491] Southwestern Electric Power Company (SWEPCO), Southwestern Public Service Company (SPS), and Entergy Texas, Inc. (ETI) all have had PUC-approved 1NCP allocations for distribution-demand related costs. TIEC Ex. 9 at 15-16 (showing a comparison of PUC adopted class allocation treatments in Dockets 43695, 40443, and 39896). Similarly, Oncor Electric Delivery Company (Oncor) and Texas-New Mexico Power Company (TNMP) have both consistently applied the 1NCP method to allocate distribution plant and related expenses. TIEC Ex. 1 at 28.
[492] TIEC Ex. 1 at 28-29.
[493] AE Ex. 8 at 22.

The IHE finds that AE has articulated reasonable policy choices for retaining the 12NCP method. AE stated that certain rate classes may be able to avoid a portion of distribution demand related costs by shifting demand during NCP periods. Furthermore, the IHE is concerned that, like TIEC and NXP's production-demand proposal, their distribution-demand proposal is results-oriented, and serves to shift cost responsibility for distribution costs from the non-residential customers to the residential and small commercial customers.[494] Finally, the IHE notes that the ICA supports AE's proposal of a 12NCP allocator "because it recognizes the load diversity and localized nature of distribution planning."[495] The IHE recommends that the 12NCP allocator proposed by AE be adopted.

Load Dispatch Expense

AE allocates distribution load dispatch expense to customer classes based on 12NCP demand. The ICA recommends allocating the expense on the basis of average demand because load dispatch is important in every hour of the year.[496] The ICA explains that load dispatch incorporates a multitude of information in making dispatch decisions, including the status of transmission and distribution constraints, current and forecasted weather conditions, and demand in various parts of the service area. The ICA also argues that winter storm conditions, like Winter Storm Uri, occurred outside the summer peak hours and affected continuous hours of use (and not just the expected February class peaks). The ICA concludes that average demand appropriately recognizes that load dispatch monitors the distribution system in all hours of the year.[497]

The ICA notes that this issue was subject to contested litigation is PUC Docket No. 43695. In that case, SPS allocated transmission and distribution dispatch expense based on average demand. The Commission found that SPS' allocation was reasonable. The ICA points out that the Proposal for Decision (PFD) in that case reasoned that "it is without question that load dispatching occurs every hour of every day," and goes on to state, "peak demand does not occur nearly as often as typical average demands, and that the peak demand usages are included in each class's average demand over the course of a year."[498] In discussing the use of average demand for load dispatch, the PFD cites SPS witness' statement that line loss adjusted annual kilowatt-hour energy:

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[494] AE Ex. 8 at 22-23.
[495] ICA Ex. 4 at 8-9; ICA Brief at 27.
[496] ICA Ex. 3 at 46-48.
[497] ICA Ex. 3 at 48.
[498] *Southwestern Public Service Co.*, Docket No. 43695, Proposal for Decision at 246 – 247.

(a) reflects that SPS dispatches load all year, at the high-peak, low-peak, and all times in between, to ensure reliability, and (b) represents each class's use of SPS's system over the course of a year.[499]

The IHE finds that the ICA's recommendation is reasonable and supported by precedent. The IHE is also cognizant that AE has persuasively argued for the 12NCP method for other cost allocation issues in this proceeding. Unless the ICA's proposal would create costly inconsistencies, the IHE recommends adoption of the ICA's recommendation to allocate distribution load dispatch expense on the basis of average demand.

c. Primary Distribution Demand-Related Costs

NXP and TIEC recommend removing the allocation of primary distribution poles and lines for the primary voltage above 20,000 kW class to create a separate rate class.[500] Both AE and the ICA oppose the creation of a new rate class that allocates primary distribution costs to customers near or adjacent to substations as inconsistent with ratemaking principles.[501]

AE explains that there are three primary High Load Factor Primary Voltage (≥ 20 MW) customers ("Primary Substation" customers).[502] AE notes that none of these customers are served directly from any substation on AE's system.[503] TIEC explains that Primary Substation customers are nevertheless served through dedicated radial feeder lines that are directly connected to an AE substation and do not serve other customers.[504] The industrials note that these customers do not use AE's interconnected primary distribution network of lines, poles, and conductors.[505] The industrials contend that this type of primary service is nearly identical to transmission service, except that for Primary Substation customers, AE must first transform power down to a primary distribution voltage.[506]

TIEC explains that Primary Substation service differs from the service provided to other primary distribution customers ("Primary Distribution" customers). To serve Primary Distribution

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499 *Southwestern Public Service Co.*, Docket No. 43695, Proposal for Decision at 246 – 247.
500 TIEC Ex. 1 at 31-34; NXP Ex. 1 at 32-34; NXP Brief at 35-36; TIEC Brief at 28-33.
501 ICA Ex. 4 at 9-10; ICA Brief at 29.
502 AE Ex. 8 at 25.
503 AE Ex. 8 at 25.
504 TIEC Ex. 1 at 32; TIEC Ex. 23 (AE's Response to NXP's RFI 1-5R) at 1, n.1 ("Each feeder [serving AE's Above 20 MW High Load Factor customers] does not serve other customers."); AE Ex. 8 (Burnham Reb.) at 25 (explaining that no customers are "directly" served from any substation because the POI is outside of the substation and requires a feeder); Tr. (July 15) at 76:6-20 (Burnham Cr.) (showing that the only factual dispute was over the term "directly" and it was based on the ownership of the feeder line).
505 TIEC Ex. 1 at 31, 79.
506 TIEC Ex. 1 at 31, 79.

customers, AE must not only own the transformation equipment to step power down from transmission to distribution level, but must also construct and maintain a network of interconnected primary poles, lines, conductors, and related facilities to provide service.[507] TIEC notes that a utility must invest in hundreds if not thousands of miles of distribution wires and related facilities to serve Primary Distribution customers, and that providing that service also results in greater line losses.[508] Primary Distribution service is thus more costly to provide than Primary Substation service in terms of both infrastructure costs and line losses.[509]

The industrials argue that, despite these fundamental differences, AE groups Primary Substation customers together with Primary Distribution customers for cost-allocation purposes.[510] The industrials complain that Primary Substation customers are allocated a share of AE's total distribution network infrastructure costs even though they do not impose distribution network costs on the system, because they take service from a distribution substation through a radial feeder.[511] As a result, the industrials contend AE's COS Study should be modified to ensure that Primary Substation customers are not charged for the cost of distribution network assets that they do not use.[512]

AE claims that its policies do not allow adoption of the industrials' proposal. According to AE, the point of interconnection (POI) for all customers is outside of the AE substation.[513] AE explains that it must install and maintain the primary distribution poles and lines to serve customers up to the POI, regardless of the geographic location of the interconnection point.[514] Distribution feeders can be direct or shared and are comprised of some combination of AE owned and maintained overhead and/or underground conductors. Further, AE notes that distribution feeder lengths vary between a few hundred feet up to several miles, and there is no direct correlation between the location of the substation and a customer's property. In addition, AE explains that it is common ratemaking practice to recover system costs on a class average basis regardless of the

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[507] TIEC Ex. 1 at 79.
[508] TIEC Ex. 1 at 80.
[509] TIEC Ex. 1 at 80.
[510] TIEC Ex. 1 at 31.
[511] TIEC Ex. 1 at 31-32 ("In addition to distribution substation costs, AE allocates all Primary customers plant and related costs associated with the FERC accounts for Poles, Towers and Fixtures; Overhead Conductors and Devices; Underground Conduit; Underground Conduit and Devices; and Line Transformers.").
[512] TIEC Ex. 1 at 31-32.
[513] AE Ex. 8 at 25.
[514] AE Ex. 8 at 25.

physical location of the interconnection. As a result, primary voltage customers should be allocated costs for the primary distribution poles and lines that are part of these feeders.

AE argues that despite revising prior responses and participating in meetings with the participants directly to clarify, NXP and TIEC continue to state that Primary Substation customers are directly connected to an AE distribution substation through dedicated feeders.[515] AE contends there are no primary >=20,000 kW customers that are served directly from the substation. AE does not allow customer-owned equipment in its substations for safety concerns. Therefore, no customers are allowed to directly connect to AE substations.

The industrials respond that AE's arguments against a Primary Substation class are not based on cost-causation and are not supported by the facts. The industrials note that Primary Substation customers do not use the distribution network; their use of the utility's distribution system is limited to substations and radial feeder lines that serve only that customer. Furthermore, a Primary Substation customer maintains its own distribution network for its industrial site.[516] In his rebuttal testimony, AE witness Mr. Burnham disputed that Primary Substation customers are "directly connected to an Austin Energy distribution substation through dedicated feeders."[517] However, as noted by the industrials, at the hearing, Mr. Burnham clarified that he does not believe that these customers should be considered "directly" connected because they do not own the radial feeder.[518] Mr. Burnham does not claim that Primary Substation customers use the broader, interconnected distribution network that they are being required to fund under AE's proposal. Indeed, AE has provided a discovery response in this case that shows that the three Primary ≥ 20 MW customers are connected to dedicated feeders that each serve *no other customers*.[519]

The IHE recommends that a separate substation rate be developed for the three Primary Substation customers, and any new customers that would be covered by the terms of the new tariff. It is undisputed that all three Primary Substation customers are directly connected to AE distribution substations located adjacent to their sites through dedicated radial feeders that serve no other

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[515] TIEC Brief at 28; NXP Brief at 35.
[516] TIEC Ex. 1 at 81; Tr. (July 14) at 27:8-15 (Pollock Cr.).
[517] AE Ex. 8 at 26.
[518] Tr. (July 15) at 76:6-20 (Burnham Cr.) (showing that the only factual dispute was the term "directly" and it was based on the ownership of the feeder line); AE Ex. 8 at 25 (Burnham Reb.) (explaining that no customers are "directly" served from any substation because the POI is outside of the substation and requires a feeder).
[519] TIEC Ex. 23 (AE Response to NXP 1-5R).

customers.[520] As a result, the IHE agrees with the industrials that cost-causation principles dictate that Primary Substation customers should only bear the cost of the radial distribution feeders that are used to serve them.[521]

AE and the industrials dispute the applicability of a case where the PUC ordered Oncor to create a new tariff for Primary Substation customers who "receiv[e] voltage from, or near, a substation" and who "*construct and maintain the distribution facilities themselves*."[522] AE has argued that the Oncor precedent establishing a Primary Substation class is distinguishable because the customers in the Oncor case owned and maintained the distribution facilities at issue.[523] However, the IHE considers this argument to support direct assignment of the dedicated radial feeders for AE's Primary Substation customers.

The IHE recommends that direct assignment is better aligned with cost causation than allocating all distribution network costs to Primary Substation customers who do not use that network. As noted by the industrials, it is an accepted practice to directly assign costs to a customer or class of customers that can be identified as serving only those customers or classes, as Mr. Burnham agreed at the hearing.[524]

If AE's concern is that these dedicated feeders are included in AE's overall distribution costs, then the IHE recommends that the costs either be directly assigned to the Primary Substation customers, or allow those customers the option to purchase and maintain the necessary distribution assets, consistent with the Oncor case.[525] This would allow the customer to purchase the dedicated radial feeders or, if the customer wishes, to also purchase the transformation equipment and thus take service at the transmission level.[526]

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[520] TIEC Ex. 1 at 32; TIEC Ex. 23 (AE's Response to NXP's RFI 1-5R) at 1, n.1 ("Each feeder [serving AE's Above 20 MW High Load Factor customers] does not serve other customers."); AE Ex. 8 at 25 (Burnham Reb.) (explaining that no customers are "directly" served from any substation because the POI is outside of the substation and requires a feeder); Tr. (July 15) at 76:6-20 (Burnham Cr.) (showing that the only factual dispute was over the term "directly" and it was based on the ownership of the feeder line).

[521] TIEC Ex. 1 at 33-34. TIEC also proposes that Primary Substation customers should be allocated their portion of the costs associated with the substation.

[522] TIEC Brief at 30; NXP Brief at 36; *Application of Oncor Electric Delivery Company LLP for Authority to Change Rates,* Docket No. 35717, Order on Rehearing at 11 (Nov. 30, 2009) (emphasis added).

[523] AE Ex. 8 at 27.

[524] Tr. (July 13) at 120:3-6, 121:24-33 (Burnham Cr.). AE's own Rate Filing Package states "[c]osts that can be readily attributed to a particular customer or customer class are directly assigned to that customer or class." AE Ex. 1 at 58.

[525] TIEC Ex. 1 at 33-34.

[526] TIEC Ex. 1 at 46.

Although the IHE does not recommend whether the feeder costs should be directly assigned or owned by the customer, the primary goal of a new tariff is to ensure that all of the distribution costs associated with serving each Primary ≥ 20 MW HLF customer are being paid for by that customer, and there would be no allocation of additional distribution costs (for facilities they don't use) to that class. The IHE recommends that AE work with the industrials to implement the creation of this rate class and to remain consistent with AE policies to the extent that there is an actual, direct conflict.

2. Energy-Related Costs

Energy allocation methods are used to allocate energy-related costs.[527] Energy allocation factors are only applied to the production function costs that are recovered outside base rates under the PSA pass-through charge.[528] When electricity is transmitted and distributed, a certain percentage of energy is lost due to resistance. In general, losses are estimated by calculating the discrepancy between energy produced and energy sold to customers. Line loss factors are discussed in Section III.D.7, below. The ICA disagrees with AE's classification of Production Non-Fuel O&M Accounts, which is addressed in Section III.C.2.

3. Customer-Related Costs

The distribution and customer service functions each include customer-related costs.[529] The distribution function contains customer-related costs related to metering.[530] In the customer service function, all costs are classified as customer-related.[531]

Meter Cost Allocation

AE proposes that meter expense be allocated using a weighted customer allocator. AE contends that meter reading costs should be allocated based upon the number of customers. Over the last few years, AE has been upgrading traditional meters to smart meters.[532]

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[527] AE Ex. 1 at 64.
[528] AE Ex. 1 at 64.
[529] AE Ex. 1 at 65.
[530] AE Ex. 1 at 65.
[531] AE Ex. 1 at 65.
[532] The ICA notes that smart meters provide system benefits for modernizing the grid, acquiring information, developing revenue and usage reports, revenue protection, communicating with customers, increased reliability, enabling improved outage detection, restoring service, repairing faults and system wide recovery. The ICA also notes that societal benefits arise from direct load control, demand response, and integration of distributed generation, which reduces energy and demand, thereby applying downward pressure on energy prices in ERCOT markets and reducing the need for new generation. AE Presentations provided in response to ICA TC 1-12B.

The ICA notes that AE has been aggressive in the sophistication of the smart meters it deploys, and the implication of this technology is that substantial meter investment costs have been expended to access meter functions which transcend the standard billing and collection measurement role. The ICA proposes that, rather than having all of the meter expense allocated to customer classes based on AE's weighted customer allocation, 51% of the meter cost should be allocated based on revenue requirement.[533] The ICA reasons that the cost of a manual meter is approximately 49% of the cost of a smart meter. The remaining 51% of the smart meter cost represents investment incurred for functions which cannot be performed by a manual meter. The ICA reasons that this portion of the cost of the meter is related to the newer features that smart meters allow beyond what traditional meters would facilitate.[534]

AE responds that the additional features allowed by smart meters, such as customer reporting, communicating with customers, and remote start/stop of service, are appropriately allocated to customer classes based on AE's selected allocator.[535] According to AE, these benefits apply to all customers relatively equally and are not influenced by customer size or revenue.[536] Specific to the ICA's proposal, AE points out that allocating this expense based on revenue requirement would assign a significant amount of this cost to customer classes based on energy.[537] AE concludes that the ICA's proposal is a poor fit with the fixed cost of meters, which do not vary with energy use.

The IHE is persuaded that AE's customer-weighted cost allocation is reasonable and should be adopted. The IHE notes that NXP supports AE's position, stating that "[t]his approach is consistent with that of all major utilities in Texas, which allocate 100 percent of meter costs using a weighted meter cost allocation."[538] The ICA's primary concern appears to be the increased cost and functionality of smart meters over traditional meters. The ICA acknowledges that AE's approach is appropriate and standard for traditional meters. The IHE is not convinced that the increased functionality and cost of smart meters justifies deviating from an approach that the ICA otherwise supported. Finally, the IHE agrees that tying fixed costs to variable revenue does not match as well as tying the costs to the customer function.

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533 ICA Ex. 3 at 42-45.
534 ICA Ex. 3 at 42-45.
535 AE Ex. 6 at 10.
536 AE Ex. 6 at 10.
537 AE Ex. 6 at 10.
538 NXP Brief at 36.

FERC Accounts 911 through 917

AE proposes to allocate certain customer service expenses (FERC Accounts 911 through 917) on the basis of the number of customers in each customer class.[539]

The ICA recommends an alternative allocation of customer expenses. The ICA notes that customer service accounts include advertising and dissemination of information aimed at promoting and retaining the use of electricity and marketing the utility's services. The ICA explains that these expenditures are intended to influence system energy consumption and are related to system objectives which affect all functions and not solely the customer function.

As a result, the ICA suggests a weighted allocation comprised of 61% revenue requirement and 39% based on the number of customers.[540] According to the ICA, 61% represents the proportion of costs identified as Customer Service on Schedule G-5 of the Base Rate Package that are associated with FERC Accounts 911, 912, 913, and 916, as compared with the total costs identified as Customer Service on Schedule G-5 associated with FERC Accounts 907 through 916.[541]

AE responds that the programs reflected in this expense are targeted to smaller, less sophisticated customers—not large commercial or industrial customers.[542] As a result, AE argues that the use of a revenue requirement allocator would inappropriately allocate disproportionate amounts of this cost to the large commercial or industrial customers. AE argues that the ICA's suggestion is not equitable and that these costs are appropriately allocated based on number of customers.

The IHE recommends approval of AE's proposal to allocate customer service expenses in FERC Accounts 911 through 917 on the basis of the number of customers in each customer class. The IHE is persuaded that these costs should be allocated as AE proposes because the industrials and more sophisticated ratepayers are unlikely to benefit from such programs.

4. Revenue-Related Costs

To allocate Service Area Lighting and Energy Efficiency programs, AE used revenue-related allocation factors that distribute the cost to customer classes. However, ultimately, these

[539] AE Ex. 6 at 13.
[540] ICA Ex. 3 at 48-50.
[541] AE Ex. 6 at 12.
[542] AE Ex. 6 at 13.

expenses are removed from the base revenue requirement and collected through the CBC.[543] No participant took issue with this proposal.

5. Service Area Street Lighting

The IHE addresses the arguments of AE and NXP related to service area street lighting costs in Section II.B.10.

6. Direct Assignments

AE uses direct assignment to allocate costs that are readily attributable to a specific customer or customer class.[544] One directly-assigned expense, at issue in this base rate review, is bad debt or uncollectible expense.[545] AE assigns uncollectible expense to customer classes based upon the proportion of bad debt expense occurring within residential and non-residential classes during the prior three-year period. The ICA notes that this type of method is sometimes referred to as a direct assignment, although it does not strictly fit that label.

Instead of directly assigning such expenses, the ICA recommends that AE use revenue as the basis for allocation.[546] The ICA argues that assigning uncollectible expense to customer classes based on the proportion of bad debt expense occurring within that class during the prior three-year period is unreasonable because the direct assignment of an uncollectible expense fails to allocate the expense to "cost-causers," since those causing the cost are not paying customers.[547] The ICA contends uncollectible expense is a social cost that must be absorbed on an equitable basis across classes, since the cost-causers are no longer on the system.[548] ICA notes that (a) the NARUC CAM excludes bad debt from the customer classification;[549] (b) the RAP CAM supports the use of a class revenue allocation for uncollectible expense;[550] and (c) the PUC in Docket No. 16705 rejected a direct assignment approach in favor of revenue allocation.[551] The ICA argues that the

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[543] AE Ex. 1 at 69.
[544] AE Ex. 1 at 58; *see e.g.*, AE Ex. 1 at 58, 69-70 (AE directly assigns expenses related to AE-owned lighting distribution assets to the applicable lighting customer classes); AE Ex. 6 at 8 (AE directly assigns uncollectible expenses or bad debt to customer classes).
[545] AE Ex. 6 at 8.
[546] ICA Ex. 3 at 39-42; ICA Brief at 31-32.
[547] ICA Ex. 3 at 39-40.
[548] ICA Ex. 3 at 40.
[549] ICA Ex. 3 at 61; AE Ex. 6 at 9.
[550] ICA Brief at 32 (citing Regulatory Assistance Project CAM, *Electric Cost Allocation in a New Era* at 162 – 163).
[551] ICA Brief at 31 (citing *Entergy Gulf States, Inc*., Docket No. 16705, Second Order on Rehearing at Finding of Fact No. 231 (Oct. 14, 1998); *Application of Southwestern Public Service Co. for Authority to Change Rates*, Docket No. 43695, Order at Findings of Fact 310 and 311) (ICA cites the latter case as a 2016 Texas PUC contested case rejecting direct assignment of uncollectible expense).

RAP CAM manual proposes revenue allocation of uncollectible expense because the size of a customer class's bills affect the risk of bad debt, and "if the customer had shut down or left before rates were set, most of the costs reflected in the uncollectible bills would have been allocated to the remaining customers."[552]

AE responds that, as an MOU, it must recover the costs of doing business from its customers.[553] AE also responds to the ICA's claim that the NARUC CAM specifically excludes bad debt from the customer classification by noting that the NARUC CAM actually states the following:

> 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***.[554]

AE also criticizes the ICA's reliance on PUC precedent in Docket No. 16705.[555] AE argues that this reliance is misplaced, because the docket cited by the ICA is from 1998, which was more than 20 years ago and is therefore outdated.

AE argues that the direct assignment method recognizes that there is a different risk of uncollectible expense depending on the customer class.[556] As a result, direct assignment based on historical experience better aligns the test year cost with the customer classes that have contributed to this cost.[557] AE asserts that uncollectible expenses are simultaneously more customer-driven (as opposed to being energy-driven or demand-driven), and are most closely related to the customer-service function (as opposed to the production, transmission, or distribution functions).[558] As a result, AE argues the most prudent approach is to directly assign uncollectible expenses.[559]

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552 ICA Brief at 32; Regulatory Assistance Project CAM, *Electric Cost Allocation in a New Era* at 162 – 163.
553 AE Ex. 1 at 501 (see definition of "base rate"), 720 (see definition of "municipally owned utility").
554 AE Ex. 6 at 9; NARUC CAM at 102 (emphasis added).
555 ICA Brief at 31; *Application of Entergy Gulf States, Inc. for Approval of its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Underrecovered Fuel Costs*, Docket No. 16705, Second Order on Rehearing at Finding of Fact No. 231 (Oct. 14, 1998).
556 AE Ex. 6 at 9.
557 AE Ex. 6 at 9.
558 AE Ex. 6 at 8-9; AE Ex. 9 at 43.
559 AE Ex. 6 at 8.

As discussed above at Section III.B.4.b. - Bad Debt, the IHE agrees that uncollectible expenses are more customer-driven than energy-driven or demand-driven, and the cost causes are more closely related to customer service, than production, transmission, or distribution. The IHE recognizes that the direct allocation method attempts to account for the varying risks of uncollectible expense that AE has historically been able to identify and assign directly to a customer or customer class. The ICA's arguments fail to convince the IHE that the revenue allocation method is a better approach than direct assignment for allocating expenses that are readily attributable to a specific customer or particular customer class. The IHE is not persuaded that the revenue allocation approach more equitably addresses the cost of bad debt. Furthermore, the sources the ICA cites in support of its position do not reject direct assignment, generally. Nor do those sources reject consideration of direct cost allocations according to class. Accordingly, the IHE recommends direct assignment to allocate costs that are readily attributable to a particular customer or customer class, as proposed by AE.

7. Energy and Demand Line Loss Factors

AE relied upon the System Loss Study for FY 2018 (Line Loss Study) to adjust normalized energy sales and demands at the meter for each customer class to the generation level to adjust for the percent energy losses at each applicable voltage level.[560] NXP and TIEC claim that AE's Line Loss Study was conducted in error.[561] NXP and TIEC recommend the use of demand losses for CP cost allocation.[562] AE does not disagree with their recommendation, and notes that demand losses should be utilized to adjust load. However, AE only has a demand loss measured for the peak hour of the year (1CP).[563] AE does not have a demand loss measured for each peak hour of the month applicable to the 12CP cost allocation.[564] Losses would be expected to be different at different loads and different ambient temperatures throughout the year.[565] Therefore, the use of the average energy loss as a proxy for the 12CP demand loss is reasonable and acceptable.

The industrials also recommend the use of demand losses for NCP cost allocation.[566] AE disagrees and argues the NCP of a customer class may occur at any time during the month and the

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560 AE Ex. 1 at App. 361-386. The Line Loss Study was filed on June 6, 2022 as an Amendment to the Base Rate Package.
561 NXP Brief at 38; TIEC Brief at 33-36.
562 TIEC Ex. 1 at 36; NXP Ex. 1 at 37-38.
563 AE Ex. 8 at 24.
564 AE Ex. 8 at 24.
565 AE Ex. 8 at 24.
566 TIEC Ex. 1 at 36; NXP Ex. 1 at 37-38.

losses associated with the peak for the class would prove difficult to measure on a consistent and regular basis.[567] Instead, AE contends that the use of the average energy losses as a proxy for the 12NCP demand loss is reasonable.

TIEC purports to have created the "correct methodology for directly deriving energy and peak demand loss factors from AE's loss study."[568] AE disagrees with the proposed loss calculations provided by TIEC and has several concerns with the analysis. For example, the same demand loss factor appears to have been applied to the CP hour and the NCP hour for each month, which AE argues does not take into account variations in demand or ambient conditions by season.[569] As a result, AE opposes NXP and TIEC's recommendations.

The IHE proposes that AE and the industrials revisit this issue to determine whether the necessary data can be developed. Although AE agrees with NXP and TIEC that demand losses should be utilized to adjust load, AE claims it does not have a demand loss measured for each peak hour of the month applicable to the 12CP cost allocation.[570] It is unclear to the IHE whether this information cannot be obtained, is impractical to obtain, or whether a solution could be developed. The IHE does not reject as unreasonable AE's use of the average energy loss as a proxy for the 12CP demand loss. However, the IHE recommends that if reasonable adjustments could be made to AE's Line Loss Study to accommodate the industrials' concerns, then AE should cooperate with them in that endeavor.

8. Cost Allocation Summary

The IHE has largely adopted AE's class allocation proposals, including the following: adoption of the ERCOT 12CP methodology to allocate the cost of generation; adoption of the 12NCP allocator for distribution substations, poles, and conductors; allocating meter expense using a weighted customer allocator; allocating meter reading costs and certain customer service expenses (FERC Accounts 911 through 917) based upon the number of customers in each customer class; and use of direct assignment to allocate Uncollectible Expense. AE's allocated COS Study and recommendations above are consistent with cost-causation principles and should be adopted.

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567 AE Ex. 8 at 24.
568 TIEC Brief at 34; TIEC Ex. 1 at Ex.t JP-8.
569 AE Ex. 8 at 25.
570 AE Ex. 8 at 24.

The IHE disagrees with AE in the following areas, for which the IHE recommends adoption of: (1) a new Primary Substation rate class as proposed by NXP and TIEC; (2) ICA's recommendation to allocate distribution load dispatch expense on the basis of average demand; and (3) a potential update of the Line Loss Study per NXP and TIEC's proposal.

E. Cost of Service Results

AE notes that its total COS results are presented in the Base Rate Package in Table 5-O.[571] AE acknowledges that Table 5-O lacks adjustments made based on accepted proposals by various participants. AE argues that the results highlight that the residential customer class is under-recovering relative to its COS, while the non-residential customer classes, as a group, are over-recovering, some by a substantial margin.[572] The COS findings, which prompted AE's proposed rate design, are discussed in Section V.

F. Cost Allocation Conclusions

AE's cost allocation proposals should be adopted as noted above. The COS Study indicates adjustments are needed to align all classes with their total COS. As discussed below, AE's proposed class revenue distribution is designed to move classes toward their COS without producing unacceptably large customer impacts.[573] Although the IHE recommends AE revisit its rate design to consider vulnerable customers who are not covered by CAP, the IHE finds AE's class revenue distribution proposal appropriate. AE recognizes that the current economic and affordability conditions in AE's service area could not support a complete shift to full COS or the accompanying rate shock that such an immediate change would cause.[574] As a result, AE argues that it applies a moderate approach to address COS imbalances to mitigate rate shock.[575] AE uses the COS Study results as the foundation for developing the class revenue distribution and proposed base rates, discussed next.

IV. Class Revenue Distribution

AE's Position

AE's COS Study indicates that, under its current base rates, significant inter-class cross-subsidization exists. AE has therefore proposed a gradual approach to revenue distribution.[576]

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[571] AE Ex. 1 at 73.
[572] AE Ex. 1 at 73.
[573] AE Ex. 1 at 73.
[574] AE Ex. 1 at 73.
[575] AE Ex. 1 at 73.
[576] AE Ex. 1 at 73.

Under AE's proposal, target revenues are set below cost of service for certain classes to avoid excessive rate impacts for those classes.[577] AE acknowledges that setting target revenues below cost for some classes necessarily requires that the revenue contributions from certain other classes will be set somewhat above cost of service. AE submits that its proposal avoids setting class revenues directly and immediately to class cost of service, because that approach would result in a dramatic increase in base rates for the residential classes that are currently well below cost of service.[578] AE's stated goal is for each class's revenue target to be set directly to cost of service. However, AE submits that if base rates were set directly to cost in this proceeding, it would promote an unacceptable degree of rate impact, so AE proposes implementing a gradualist approach to class revenue distribution.

AE refers to its class revenue distribution approach as "halfway to cost."[579] Under AE's proposal, all classes receive the system average increase or decrease in step one.[580] Then, from each class's position after step one, each class moves halfway toward cost of service.[581] AE submits its methodology balances several policy objectives, including fairness, recognition of cost of service, and gradualism.

Several participants have concerns with AE's "halfway to cost" approach. Those participants propose alternative class revenue distribution methodologies, as discussed below.

The ICA's Position

The ICA raises various concerns with AE's approach. First, the ICA argues that revenue distribution should not be based solely on cost of service. The ICA argues that rate impact, non-cost considerations, promoting efficient behavior, and public policy are also relevant factors.

Second, the ICA argues that the later stages of the COVID pandemic, and its significant economic impacts, are embedded in the 2021 test year. As a result, the ICA argues there is the potential that future customer class composition and capacity for revenue generation will vary significantly from test year conditions.

Third, the ICA argues that AE's attempt at customer class revenue distribution severely impacts the residential class. The ICA submits that the proposed 17.6% revenue increase for the

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577 AE Ex. 1 at 73.
578 AE Ex. 1 at 73.
579 AE Ex. 1 at 73.
580 AE Ex. 1 at 73.
581 AE Ex. 1 at 73.

residential class is excessive and produces an immense impact on households in the AE service area.[582] The ICA also submits that assigning revenue reductions to some classes while overall revenues increase is a violation of the principles of moderation and public acceptability. In the ICA's view, the most equitable approach precludes a revenue reduction for any class when the overall retail system faces a significant revenue increase. The ICA argues that selected revenue reductions for some customers compound the severity of revenue increases confronting most customers.

The ICA proposes an alternative two-step approach to class revenue distribution. The first step is to apply a percentage increase of one-half 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. The ICA submits that its approach suppresses large impacts, broadly shares the revenue increase, and recognizes classes with revenues substantially above cost.

NXP's Position

As a threshold issue, NXP argues that there is no evidence that supports AE's requested revenue distribution. NXP notes that AE's rebuttal case changed several revenue requirement items, each of which is allocated differently from the other. According to NXP, this means that the 25% reduction in overall revenue increase requested does not flow through to classes the same way that the original request did. In addition, NXP submits that AE does not plan to update its cost of service model until after briefing, so the IHE (and other parties) have no means at their disposal to see how AE's proposed revenue distribution methodology would actually flow through to AE's proposed customer classes. NXP argues this represents a fatal flaw in the utility's rate application.

In addition, NXP takes issue with the first step of AE's proposal, which would impose a revenue increase of the proposed system average percent base rate revenue increase on all classes, regardless of whether the class is currently over- or under-collecting revenue. NXP asserts that the first step results in certain classes – namely classes that are currently over-paying – receiving less of a reduction than they might otherwise receive. For instance, NXP submits that the Secondary Voltage Greater Than 300 kw customer class's current revenues are already above the class's cost of service. NXP notes that increasing the class's current revenues by the overall percent revenue increase needed of 7.6% moves this class further above its cost of service. NXP submits that the

[582] ICA Ex. 3 at 56.

50% movement toward cost of service actually reduces their rates less than if this class's rates were not already artificially increased by 7.5%.

In lieu of the AE method, NXP proposes moving classes that are currently significantly below or above their allocated costs 1/3 closer to their cost of service.[583] Thereafter, NXP proposes allocating the remaining customer class subsidies after the 1/3 move to cost of service to the other customer classes by proportionately spreading the "net" over-recovery (their cost of service over-recovery less the subsidies) to the other classes based on their cost of service so that some of the subsidy they currently pay is reduced.[584] NXP submits that this approach has the advantage of moving the residential class closer to cost of service, but without a significant rate increase. NXP further submits that its proposal would largely control the rate increases (or reductions) on other classes, while working towards cost of service. Finally, NXP argues that its proposal would not cause other classes to subsidize one another to the same extent.

TIEC's Position

TIEC's position is that base revenues should reflect the actual cost of providing service to each customer class as closely as practicable, but that regulators may limit the immediate movement to cost based on gradualism. As a result, TIEC argues that AE should implement a class revenue distribution that is based on the results of a proper COS study, which is designed to evaluate whether each class is appropriately contributing to its actual cost of service. TIEC argues that cost-based rates are fair, efficient, enhance revenue stability, and encourage conservation.[585] According to TIEC, AE's proposed class revenue allocation is not cost-based because it actually moves two customer classes—Primary ≥ 3 MW < 20 MW and the High Load Factor Primary ≥ 20 MW classes—further from cost. TIEC notes that these classes would receive rate increases when an appropriate COS study, as developed by Mr. Pollock, demonstrates that they should receive reductions.[586]

TIEC recommends moving all customer classes to cost, unless it would cause excessive rate impacts to any particular class considering the revenue requirement and allocation methodologies that are ultimately adopted.[587] TIEC submits that if the IHE determines that

[583] NXP Ex. 1 at 43.
[584] NXP Ex. 1 at 43.
[585] NXP Ex. 1 at 40-41.
[586] NXP Ex. 1 at 41.
[587] NXP Ex. 1 at 42.

movement to cost should be balanced with the principle of gradualism, the two Primary Voltage classes should at least move in the direction of cost, and should have their base rates reduced by at least 30% of the cost-based reductions reflected in Mr. Pollock's corrected COS study, which would result in a 2% reduction for the Primary ≥ 3 MW < 20 MW class and a 7.7% reduction for the High Load Factor Primary ≥ 20 MW class.[588] TIEC argues that adopting 30% of the cost-based reductions under a gradualism approach would be consistent with AE's proposal for the classes that are currently above cost under AE's COS Study, which AE suggests should receive between 24-33% of their cost-based rate decreases.[589]

IHE's Recommendation

The IHE recognizes AE's current disparity between target revenues and the cost of service. Although the IHE generally agrees that revenues should be set at cost for all customer classes, the IHE is also concerned that this could cause rate shock for certain lower tier residential ratepayers. Some form of gradualism is necessary and appropriate in this case. Subject to the rate design ultimately adopted, the IHE recommends AE has proposed a reasonable, standardized approach that ultimately moves all classes closer to cost of service. The IHE also acknowledges that adoption of the AE's recommendation is subject to AE updating its cost of service model.

The IHE is sympathetic to the concerns of the ICA regarding non-cost-based factors being considered when setting target revenues and that AE's proposal has the greatest impact on the residential customer class. However, the IHE agrees with AE, NXP, and TIEC that revenues should, subject to the rate design adopted and gradualism concerns, be set as close to cost as possible. While the IHE recognizes NXP's concern with the first step of AE's approach, the IHE is mindful that the first step is an intermediate step and not the ultimate outcome – which undoubtedly moves all classes closer to cost of service. Similarly, while TIEC contends that AE's proposal results in some classes moving further away from cost of service, the IHE agrees with AE that TIEC's concern is based on its own COS study, and not AE's COS Study, to which AE's class revenue distribution methodology has been applied.

Additionally, the IHE recognizes that the three alternative proposals submitted by the ICA, NXP, and TIEC would likely also result in the common goal of all classes moving closer to cost. That said, the IHE is not persuaded that any party has demonstrated that AE's proposed "halfway

[588] NXP Ex. 1 at 42.
[589] NXP Ex. 1 at 42.

to cost" method is unreasonable, unjust, or discriminatory. Accordingly, the IHE recommends adoption of AE's class revenue distribution method.

V. Rate Design

A. Residential Rate Design

1. Introduction

AE has proposed significant changes to its residential base rate design. Many of these changes are opposed by other participants, particularly ICA, SCPC/SUN, 2WR, and Mr. Robbins. AE states that the rate design proposals are in response to changes in customers' use of the system since the current design was adopted in 2012. The Base Rate Package states that these changes are necessary due to an increasing share of multi-family as compared to single-family homes, the housing mix becoming smaller and more efficient, and an increase in energy efficiency.[590] Accordingly, declining average consumption keeps energy sales flat despite customer growth.[591] As a result, AE argues that revenue growth is hampered by a residential base rate design that relies too heavily on energy sales.[592] AE further notes that the current steep five-tier structure results in certain residential customers being subsidized by other residential customers that reside in the higher tiers.[593]

AE proposes to alter the residential base rate structure to better recover fixed costs by relying less on energy sales, thus bringing customers closer to what it costs to serve them.[594] AE characterizes this as a more equitable arrangement than the present structure. Specifically, AE proposes to: (1) reduce the number of residential rate tiers for inside-city customers from five to three; (2) flatten the tiers; (3) significantly increase the customer charge; and (4) eliminate the base rate differential between inside- and outside-city customers. These proposals are discussed below.

As detailed in the conservation section, below, several participants have argued that AE's rate design proposal disincentivizes energy efficiency and conservation, weaking the price signals that encourage customer conservation measures and interfering with the expectations of customers who have invested in energy efficiency measures. AE responds that its proposed rate design still predominantly focuses on conservation, both because (a) one hundred percent of the demand costs

[590] AE Ex. 1 at 78-79.
[591] AE Ex. 1 at 9.
[592] AE Ex. 1 at 9.
[593] AE Ex. 1 at 9.
[594] AE Ex. 1 at 10.

are designed to be recovered in energy rates,[595] and (b) the energy rates are proposed in three tiers of inclining blocks of consumption, which amplifies the conservation price signals.[596] As detailed below, AE argues that its analyses suggest that changes in the base rate structure are unlikely to change customer conservation behavior. This conclusion is disputed by certain participants.

Participants, including ICA, also argue that AE's rate design proposal would significantly raise costs for low usage customers, including economically vulnerable customers. These participants further argue AE's rate design proposal is inconsistent with the principle of gradualism, exposing certain subsets of the residential customer class to rate shock. In response, AE argues that impacts on vulnerable customers are addressed by its low-income assistance program, CAP, and that low-income users are more likely to be high-usage customers, and thus potentially benefit from the redesign. As discussed below, ICA and other participants object to both arguments.

AE argues that certain goals raised by the participants, including conservation goals such as supporting distributed generation and maintaining affordability for lower income customers, fall outside traditional rate design and thus should be disregarded, or given little weight compared to AE's stated rate design goals of increasing financial stability and moving customer classes toward their cost of service. Other participants maintain that conservation and affordability goals are legitimate goals that should be taken into account in determining the residential base rate design.

As discussed below, the IHE finds that both AE and the participants offer cogent arguments supporting their positions, but there is an underlying disagreement on how these various goals should be considered or balanced through rate design.

Although the ultimate policy decisions rest with City Council, the IHE recommends balancing AE's legitimate policy priorities of financial stability with limiting rate shock for those vulnerable customers who are not covered by CAP. The policy choices include whether conservation, affordability, and gradualism (within the intra-customer class context) should be subordinated to AE's legitimate goals of increasing financial stability and aligning to intra-class cost causation. A different policy choice is whether rate design must maintain affordability for

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[595] AE Ex. 9 at 27.
[596] AE Ex. 9 at 27.

certain subsets of the residential class, including vulnerable customers not served by CAP, and the proper application of gradualism to avoid rate shock for those customers.

The latter may result in subsidization by other rate classes, which AE and industrial consumers seek to avoid. Here, the alternative rate design proposed by ICA, with four tiers and a fixed charge of $13, would provide a potential *starting point*, and ideally this would be open to some modification once final numbers are run and kWh prices for each tier have been determined. The IHE is aware that whatever residential rate design is adopted it must ultimately collect sufficient revenue to meet AE's revenue requirement as allocated to the residential class.

2. Financial Stability

AE's rationale for seeking a base rate increase is that its financial position is deteriorating. AE's last base rate increase occurred a decade ago in 2012 (in 2017 it reduced rates).[597] AE had a combined net loss of $90 million in FYs 2020 and 2021.[598] AE offered evidence that since its last ratemaking test year (FY 2014) prices have increased 16.5% while rates have remained unchanged.[599] AE also stated that in the last twelve months alone, prices have increased 15%.[600] Based on the COS Study using test year FY 2021, and following incorporation of some participant comments, AE has proposed a $35.7 million base rate increase.

As discussed in Section II, participants have argued that portions of this base rate increase are unnecessary, but the IHE recommends that many of these arguments be rejected. AE has articulated reasonable goals and policies designed to increase its financial stability.

AE notes that Fitch Credit Ratings downgraded AE from 'AA' to 'AA-.' AE warns that accepting the majority of participants' recommendations would accelerate the deterioration of AE's financial position, further increase AE's leverage, decrease AE's operating cash flow, force AE to expend its cash and reserves, and increase its debt. As noted elsewhere in this report, in contrast to a profit-seeking IOU, AE is a non-profit MOU that seeks to earn sufficient revenue in order to effectively deliver electric service to its customers at cost.[601] As an MOU, all risks and rewards are borne by the customers, and AE is tasked with managing risks on behalf of its

[597] AE Ex. 3 at 5.
[598] AE Ex. 3 at 5.
[599] AE Ex. 3 at 5.
[600] AE Ex. 3 at 5.
[601] AE Ex. 3 at 29.

customers. AE argues that its residential rate design proposal moves base rates closer to cost of service and sends appropriate price signals to customers for good energy decision-making.

AE argues that financial stability must be given more weight than participant proposals concerning purported energy-efficiency and consumption effects. AE states that over-focusing on energy efficiency ignores other important rate design tenets, such as effectively yielding the revenue requirement and providing stable revenues.[602] AE notes that it must set rates to comply with its financial policies and bond covenants. In setting rates, AE argues that it follows standard ratemaking principles identified in the Base Rate Package. One of these principles is to ensure the long-term financial strength of the utility.[603] AE argues that current base rates and tariff structures do not support the long-run financial strength and stability of the utility, and so its proposed changes to the residential base rate design are needed to support the continued viability of AE to meet current and future obligations.

The ICA challenges whether the past revenue shortfall identified by AE is indicative of future trends.[604] The ICA argues that the figures AE relies on are unadjusted and not normalized for weather or non-recurring events.[605] As discussed above, the ICA contends that AE's purported revenue gap primarily pertains to 2020 and 2021, when revenues and costs were likely to have been strongly affected by both COVID and Winter Storm Uri.[606] The IHE finds, however, that while the ICA identified several factors stemming from these events, it failed to provide persuasive analysis of the magnitude of these impacts. The IHE is not persuaded that a future shortfall is unlikely if the current rate structure and rates were maintained.

AE also argues that changes to the residential base rate structure are necessary to capture the new composition of the residential customer class. As discussed below, AE offered evidence that there are fewer high-energy-use residential customers and that growth in sales is occurring primarily in lower tier users. AE argues that this shift has caused the residential class as a whole to move further from cost of service since the last rate review. As a result, AE seeks to adjust its residential base rate design to rely more heavily on cost recovery at lower levels of consumption.

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[602] Revenue stability refers to maintaining adequate revenues and cash flow to meet costs on a year-to-year basis. AE Ex. 3 at 30.
[603] AE cites James C. Bonbright's Principles of Public Utility Rates for the proposition that ongoing revenue stability is a key principle in ratemaking throughout the electric utility industry. AE Ex. 3 at 30; James C. Bonbright, et al, *Principles of Public Utility Rates* at 383 (2d. ed. 1988).
[604] ICA Ex. 3 at 66.
[605] ICA Ex. 3 at 66.
[606] ICA Ex. 3 at 66.

AE also points out that its service territory has been experiencing unprecedented customer growth, including among residential customers.[607] AE states it has made significant utility infrastructure investments in power production, transmission lines, substations, distribution poles and conductors, customer support systems, and support services, totaling $2.1 billion from FY 2014 to FY 2021.[608] New customers also require customer support services such as customer care, billing systems, meters, customer records systems, and a number of other services that cause AE to incur incremental costs, regardless of a customer's usage.[609] In short, when customers join the system, AE's total costs increase.

AE argues that because it relies heavily on energy sales to recover its costs, increased costs must be met with a corresponding increase in sales revenues if AE is going to remain financially healthy. AE provided evidence that sales growth has failed to keep up with customer growth.[610] As a result, AE argues that from a financial standpoint, the current residential rate design is unsustainable, and a dramatic shift in rate design is necessary.

Finally, AE argues that its proposal promotes financial stability by reducing weather-based volatility in revenues. Under the current residential rate design, fixed customer costs are included in energy rates, which AE argues may result in volatile revenues because energy rates, unlike a fixed customer charge, are subject to weather fluctuations.[611] Under the existing rate structure, AE claims that it will under-recover its costs if it experiences a mild summer and energy sales are lower than average.[612] AE's data suggests that under the current rate structure, actual revenues can fall within an envelope that covers a range of almost $70 million above or below expected revenues.[613] AE contends its proposed base rate design reduces this volatility by increasing the customer charge and flattening the tiers, both of which lessen the susceptibility of base revenues to weather fluctuations.[614]

2WR counters that regardless of weather variability, once anomalies are excluded, AE has maintained revenue stability. 2WR points out that low revenues from unexpectedly mild summers are more than offset by corresponding high revenues from hot summers; as a result, weather

[607] AE Ex. 1 at 97.
[608] AE Ex. 1 at 98.
[609] AE Ex. 1 at 99.
[610] AE Ex. 1 at 99.
[611] AE Ex. 1 at 116.
[612] AE Ex. 1 at 116-117.
[613] AE Ex. 1 at 117.
[614] AE Ex. 1 at 117.

variation provides AE an overall revenue benefit over a planning horizon of five years. 2WR suggests, to the extent that AE is not already doing so, that reserve excess revenues from warmer years be used to offset low-revenue mild summers. On this issue, the IHE finds that a persistent under-collection of revenue is of greater concern than revenue volatility for a utility with well-developed hedging mechanisms such as AE.

The IHE finds that AE has established that, under the current structure, it is not collecting sufficient revenue from the residential class to ensure its financial stability. Though questions were raised concerning the typicality of the test year in terms of revenue and consumption, the IHE does not find that the participants made a compelling showing to contradict AE's overall claim. However, AE has not offered a complete analysis of its ability to secure additional needed revenue from the residential customer class.

In general, AE has established that its rate design proposal addresses its financial stability concerns. Other considerations, however, militate against adopting AE's proposed rate design. Due to concern over rate shock for vulnerable rate payers, the IHE recommends City Council direct AE to develop alternative rate design proposals to achieve the necessary revenue requirement from the residential class. Perhaps AE could explore kWh rates to achieve its revenue goals at each tier. The ICA also proposed an alternative customer charge and tier design. To the extent that the City Council agrees that AE's proposed rate design is not acceptable, alternatives that include subsidization may need to be explored.

3. Fairness and Subsidy

AE argues that under the present inclined residential tiered energy rates, as customers consume more, they pay more per kWh.[615] AE notes that this is true no matter how much it costs AE to serve the customers or how efficiently they use the system, which it argues represents a fairness issue with the current base rate structure. Under the existing five-tier structure, AE contends that the first and second tiers are priced below cost and are subsidized by the fourth and fifth tiers that are above cost. AE's RFP calculates that more than 40% of residential customers are being subsidized by other residential customers that reside in the higher tiers.[616] AE argues that under traditional rate design principles, such subsidy is undesirable, in addition to creating financial instability.

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[615] AE Ex. 1 at 122.
[616] AE Ex. 3 at 12, *citing* AE Ex. 1 at 289.

AE argues that its proposed base rates address the subsidy issue it identifies by lowering the rate differentials between tiers as well as reducing the number of tiers. The overall effect of this proposed redesign is that the amount of subsidy will be much lower and the prices charged to customers will be more closely aligned with the cost to serve them. AE likewise argues that increasing the customer charge is fair, arguing that the $25 charge more closely corresponds to fixed customer costs that do not vary with consumption. To the extent that the customer charge is set at a level below that needed to recover fixed customer costs, AE argues that higher kWh usage customers are subsidizing lower kWh usage customers, since a portion of the fixed costs are recovered in energy charges.

The ICA casts doubt on AE's analysis of the cost causation contribution and cross subsidy analysis for different tiers of residential customers. According to the ICA, it is not appropriate to use the COS Study to analyze whether customers of various usage levels are above or below cost, because the study allocates costs to customer classes, not to subsets of those classes or individual customers.[617] The ICA contends that allocation factors for assigning costs to classes are not the same measures as the rate components within a rate structure, so using the COS Study in this manner could result in serious inaccuracies.[618] The ICA argues that the COS Study makes an unfounded assumption that energy use has strict linear relationship with the various demand allocators in the study.[619] The ICA notes that a proper analysis for rate design should focus on marginal costs rather than embedded costs. Finally, the ICA contends that using the COS Study for intra-class cost analysis does not account for trends of differing customer density of low versus high energy users; the ICA argues that higher density customers impose a lesser share of infrastructure cost.[620] As a result, the ICA contends that AE's customer cost-causation and subsidy conclusions are unreliable and the principle of gradualism should override AE's interest in a flatter rate design.

2WR also criticizes AE's analysis of intra-class subsidy. 2WR argues that AE is utilizing average cost to view the rate design by the usage tiers, wrongly assuming that electricity has the same unit cost across different usage levels. 2WR points out that AE witness Burnham explained that, as usage increases, more capacity is required, resulting in increased costs as more expensive

[617] ICA Ex. 3 at 74.
[618] ICA Ex. 3 at 74.
[619] ICA Ex. 3 at 74.
[620] ICA Ex. 3 at 74.

capacity comes into the ERCOT market.[621] 2WR further claims that AE's use of 12CP to allocate plant costs recognizes that costs increase because of increased usage throughout the year. 2WR concludes that the current five-tiered rate structure tracks this uneven cost causation. The IHE is unaware of specific evidence that the five-tier model is designed for this purpose, and this alternative view of cost causation would require specific data and analysis in support to be persuasive.

AE contends that its proposal mitigates fairness issues with respect to customers' load factors. AE argues that its capacity costs for residential customers are primarily driven by peak demand, rather than by total energy.[622] For residential customers, AE currently recovers its capacity costs through charges on total energy.[623] AE posits that customers with flatter load profiles are effectively subsidizing capacity costs to serve customers with more peaked load profiles, because both are charged according to total energy irrespective of load profile.[624] AE argues that its proposed base rate design mitigates this issue by increasing the customer charge and flattening the tiers.[625]

Finally, AE argues that its proposed residential base rate structure is more transparent and offers adequate support to lower income customers.[626] AE contends that reducing the energy burden on vulnerable customers is best addressed through targeted programs rather than rate structures. According to AE, using rate structures to support lower income customers can have unintended consequences for both the customer and AE, although AE does not specify the consequences.[627]

As for targeted customer assistance programs, AE points to CAP, which assists vulnerable customers by waiving the customer charge and giving a 10% discount on energy charges for those who qualify.[628] CAP is funded through the CBC. AE argues that this is a direct and transparent way to provide bill assistance, as opposed to altering the base rate structure, which are designed to recover costs.[629] AE proposes that all bill assistance for vulnerable customers be provided in a

[621] AE Ex. 8 at 8-15; Tr. (Jul. 15) at 52:22 - 53:14.
[622] AE Ex. 1 at 120.
[623] AE Ex. 1 at 121.
[624] AE Ex. 1 at 121.
[625] AE Ex. 1 at 121.
[626] AE Ex. 1 at 123.
[627] AE Ex. 1 at 123.
[628] AE Ex. 1 at 123.
[629] AE Ex. 1 at 123.

transparent manner under the CBC. AE also contends that the proposed base rate design mitigates the provision of opaque bill assistance to low usage customers by flattening the tier structure.[630] Finally, AE notes that waiver of the increased customer charge necessarily increases the value of CAP per customer.[631]

The IHE agrees with AE that specific programs to address economically vulnerable customers, funded through the CBC, is a more transparent method to provide bill assistance to lower income individuals than a subsidy contained within the base rate structure itself. However, the IHE also finds that the participants have raised serious questions regarding the scope and efficacy of the CAP program as a mechanism to protect economically vulnerable customers as well as the potential for rate shock under AE's proposed rate structure. The ICA and 2WR have expressed concerns for certain customers vulnerable to rate shock. Although the IHE finds that AE has presented a reasonable gradualism proposal, the IHE agrees with ICA's and 2WR's affordability and gradualism concerns and recommends that the parties revisit either AE's rate design, CAP, or perhaps different customer assistance programs. As noted throughout this discussion of rate design, the IHE views this issue as a policy decision for City Council.

The IHE finds that under the current tier system, high tier customers pay rates that exceed their allocated cost of service and low tier customers pay rates below their allocated cost of service.[632] The IHE agrees with AE that this is a form of subsidy. Certain parties have argued that, under traditional ratemaking principles, any departure from cost of service should be considered unfair. However, the IHE's concerns over customers who are vulnerable to rate shock are also based on the concept of fairness. The IHE suggests that a fair (or reasonable) rate structure may account for other considerations in addition to cost of service.

For instance, the IHE notes that to serve the policy goal of reduced energy consumption, a tiered rate structure could be designed to send customers conservation price signals above the cost of service. If such a system is unfair, it is unfair by design. Furthermore, if conservation goals are broadly shared by ratepayers, then rates may be designed to achieve goals other than strictly adhering to the cost to serve. Deciding whether AE's proposed rate structure is fairer (or more reasonable) than the existing structure requires an accepted definition of fairness; between AE and

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[630] AE Ex. 1 at 123.
[631] AE Ex. 1 at 123-124.
[632] AE Ex. 3 at 12, *citing* AE Ex. 1 at 289; AE Ex. 1 at 122.

some participants, this definition is contested. Ultimately, what is reasonable or fair is not based solely on an objective cost of service figure.

B. Rate Design and Conservation

Several participants have criticized AE's proposed rate design by arguing that it will significantly weaken conservation price signals, undermining the City's and AE's goal of energy conservation. There are two primary arguments concerning rate design and conservation: whether energy conservation is a legitimate goal of rate design and AE's argument that its customers are not responsive to conservation price signals.

AE contends that it is committed to energy conservation, which is prioritized in the proposed rate design.[633] AE, however, questions the extent to which energy conservation is a legitimate factor to be included in residential rate design under ratemaking principles.[634] AE asserts that it has been unable to detect a quantitative relationship between changes in rate structure and changes in conservation.[635]

AE also questions whether a preference for distributed generation is a legitimate factor in rate design. AE claims distorting base rates to incentivize distributed generation is inconsistent with ratemaking policy.[636] To that end, AE notes that it promotes distributed generation and renewable generation through various practices outside of base rates, so it need not be a consideration in designing the structure of base rates.[637]

SCPC/SUN respond that AE's Base Rate Package states that it has consistently maintained rates with strong incentives for customers to conserve energy, implemented rate design with strong price signals for energy efficiency,[638] while working to keep rates affordable.[639] SCPC/SUN argues that the reduction of residential customer energy consumption is due in part to these policies. Mr. Robbins notes that the City has encouraged a culture of energy conservation since the 1980s. Between 1982 and 1997, a separate City department was in charge of programs related to energy efficiency retrofits, the energy building code, and the green builder program. In 1997, these programs were merged into AE.

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633 AE Ex. 9 at 27.
634 AE Ex. 9 at 26-27.
635 AE Ex. 1 at 87-130; AE Ex. 9 at 28.
636 AE Ex. 9 at 34.
637 AE Ex. 9 at 35.
638 AE Ex. 1 at 78-87, 114-115.
639 AE Ex. 1 at 114-115.

SCPC/SUN and Mr. Robbins argue that changing federal appliance standards, smaller new buildings, and updated building codes cannot account for the sharp decline in average residential consumption (13% since the 2013 implementation of the five-tier system). Without a satisfying explanation for that drop in residential consumption, it is reasonable to believe that the tiered price structure has worked as intended—sending conservation price signals to which residential customers have responded. These participants also point out that AE's analysis runs contrary to accepted principles of price elasticity;[640] that overcoming the presumptions of the general elastic demand model would require much more compelling evidence than AE's analysis.

AE responds that the participants failed to offer their own evidence that AE customers are responding to conservation price signals. Instead, AE contends that there is no reason to believe, as ICA and SCPC/SUN argue, that adopting AE's proposed base rate design will lead to increased consumption. AE argues that the proposed rate design will not weaken conservation price signals. AE asserts that customers do not change their behavior in response to the conservation price signals and there is no data showing consumption will increase under the proposed rate design.[641]

AE offered three analyses to support its argument that customers do not respond to the conservation price signals in the present rate structure. The first was a general observation of the change in average kWh consumption over time between inside-city customers and outside-city customers who are billed on a flatter three-tier structure. The analysis found that the reduction in consumption was roughly parallel between the two sub-groups, despite differences in the strength of a conservation price signal.

AE's other two analyses rely on a concept known as "bunching," which hypothesizes that customers will change behavior to avoid an increase in marginal cost. Bunching assumes that a customer tracks their usage over the course of the month and reduces consumption as they near a higher rate price tier to avoid crossing into that tier. AE argues that bunching was not observed in the distribution of kWh in customer bills, and only a very small percentage of customers even take steps to access information that would indicate bunching occurs. From its bunching analyses, AE concludes that the number of tiers and the breakpoints of the tiers do not have a noticeable effect on energy conservation.

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[640] Specifically, Mr. Robbins argues that. in the electric utility context, price elasticity is an established principle of ratemaking, confirmed by "any number of national and international studies." The IHE notes that a specific citation is lacking to support this claim.

[641] AE Ex. 9 at 31.

The IHE finds that AE's history reflects conservation goals as part of its mission. The IHE is not persuaded that it is improper for AE to account for energy conservation in residential rates. The IHE finds that more specific subordinate policy goals related to conservation, such as distributed generation, may be treated as part of the overall conservation policy goal. The success of these measure appears to be reflected in the decline in average residential consumption by 13% since the 2013 implementation of the five-tier system.

The IHE is also not persuaded that AE's analyses support AE's conclusions. First, under a marginal price structure, bunching may not constitute economically rational behavior (i.e., the effect of having the last kWh in a billing period falling into the next tier is minimal; only that kWh will be billed at the higher rate). Furthermore, bunching is not the only way a customer could respond to progressively higher rates through conservation measures. A customer who is sensitive to pricing may opt to purchase more energy efficient appliances, commit to behavioral changes to reduce energy consumption, or invest in solar panels. Those decisions would not be reflected in a bunching analysis. Also, while a customer may or may not be aware of the specific tier structure in making such decisions, the existence and steepness of those tiers may drive that decision making—the potential savings are larger (i.e., the price signal is stronger) under a more steeply tiered system. Certain customers calculate the expected savings of conservation efforts in the aggregate and at the time of purchase based on calculations provided by the conservation products. While a bunching analysis may illuminate a subset of customer decision-making, or lack thereof, it is inadequate to establish that customers are not responding to price signals embedded in the present rate structure or that a rate structure containing weaker price signals will not result in more consumption.

IHE finds that no party has articulated a convincing analysis on price elasticity. However, AE bears the burden of persuasion in this Base Rate Review. Because price elasticity is a fundamental assumption of consumer behavior, a comprehensive and persuasive analysis would be helpful. While the IHE finds that the inside- versus outside-city customer analysis has some persuasive value in demonstrating limited customer response to the tiered system, that analysis is not conclusive due to the potential for other explanations, as with the bunching analysis. The IHE notes the reduction in residential customer electricity use since the tiered system was introduced and the comparatively low electricity usage in Austin compared to the rest of ERCOT.

C. Rate Design and Affordability

Several participants argue the proposed rate design will increase bills for low and median income customers while leading to lower bills for higher income, higher consumption customers. The participants argue the redesign will harm vulnerable customers.

AE responds that affordability concerns are addressed by the existing CAP program. AE asserts that CAP customer usage patterns indicate these customers use more energy on average than non-CAP customers.[642] AE notes the proposed base rate design will significantly increase benefits under the CAP program, and argues the rate design will accordingly achieve greater levels of social equity among AE's residential customers. CAP customers do not pay the customer charge, so, under the proposed redesign, the value of the CAP program's waiver increases by 150%, from $10 per month to $25 per month, because of the increased customer charge.[643]

Mr. Robbins responds that only 7% of AE customers are in the CAP program. Mr. Robbins also asserts that 28% of AE customers have incomes at or below 200% of the federal poverty level, which is the income threshold for inclusion in the CAP program.[644]

Mr. Robbins also disagrees with AE's conclusion that low-income customers consume more energy than higher income customers. Mr. Robbins notes that AE's administration of the CAP program allows an unknown number of higher income customers to be enrolled in CAP, while leaving out a significant portion of lower income customers.

The IHE is unable to evaluate or quantify the CAP arguments, as an in-depth analysis of the CAP program was not part of this proceeding. It was suggested that CAP may not be a good proxy for low-income customers outside the program, as the CAP subsidy could cause participants to consume more energy than they would otherwise. Though this is certainly possible, the IHE has not been provided any data to assess the existence or magnitude this contention. The IHE does note, however, that AE's claim that the CAP program's waiver will increase by 150% does not expand the program – it is a reference to the waiver of the proposed 150% increase in the customer charge.

Mr. Robbins offers an alternative analysis of energy use by income. Using information provided by AE in discovery, Mr. Robbins analyzed average energy consumption in each zip code

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[642] AE Ex. 3 at 12, *citing* AE Ex. 1 at 105-109.

[643] AE takes issue with Mr. Robbins' characterization that AE is increasing the CAP subsidy to compensate for radical rate restructuring; AE correctly notes that it is not making direct changes to the CAP program in this proceeding, but that the increased benefits occur incidentally as a result of the redesign.

[644] Mr. Robbins presented other criticisms of the CAP program, but as discussed in Section VIII.C, the IHE finds that those argument are outside the scope of this Base Rate Review.

in the AE service area by housing type (single family, multi-unit housing, and apartments) and compared the relative consumption data in each zip code to income data for each zip code (taken from the U.S. Census's American Community Survey). According to his analysis, Mr. Robbins contends that energy use generally rises as household income rises.

SCPC/SUN also takes issue with AE's CAP analysis for several of the same reasons as Mr. Robbins. SCPC/SUN offers analyzed single-family versus multi-family housing type as a rough proxy for income. According to that analysis, single-family customers (assumed to be higher income on average) use almost twice as much energy as customers in multi-family housing.[645]

Finally, the ICA notes that if the increased revenue requirement, the changes to cost allocation, and AE's proposed class revenue distribution are adopted (which is largely the recommendation of the IHE), the residential class's rates will rise significantly.[646] When this increase is applied to AE's proposed rate structure, ICA contends that it will result in wildly divergent impacts, with some customers paying much higher rates.[647]

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. The IHE finds, however, that these questions do not completely refute AE's evidence. Mr. Robbins' analysis, for instance, may reflect an actual dynamic for some higher income customers within AE's service territory. But his analysis also raises questions over income variations within zip codes and other factors that may affect consumption, such as the potential age, energy efficiency, or size differences among the housing types analyzed among zip codes.

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. As discussed above,

[645] SCPC/SUN Ex. 3 at 14.
[646] ICA Ex. 3 at 1.
[647] The impact on low usage CAP customers is more complicated, as they might be adversely affected by the tier changes, but benefit from the increased customer charge (which is waived for them). The impacts on inside-city CAP customers are estimated on Table 8-B on AE's RFP; it shows overall bill increases to lower usage CAP customers (up to 750 kWh) and overall bill reductions to higher usage CAP customers.

the extent to which energy use is directly correlated with income is disputed by the participants, and the IHE finds that no party has offered a fully satisfying analysis.[648] 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 persuaded that AE has adequately addressed the affordability of the new rates for economically vulnerable customers.

D. Gradualism and Rate Shock

A related concern to affordability is rate shock and the principle of gradualism. Gradualism is discussed above in Section IV with respect to class revenue distribution. However, there are additional gradualism and rate shock concerns once the residential class is considered more closely.

AE argues that its proposed rate design avoids rate shock, but the overall rate increase of 7.6% is magnified for certain groups of residential customers according to the ICA. Due to class revenue distribution changes, the rate increase for the residential class as a whole is more than double, at 17.6%.[649]

When AE's proposed rate design is applied to that increase, the impact on low usage customers appears to be quite large. The ICA calculated the bill impact of AE's proposed rate design as a 17.81% increase on a customer consuming 875 kWh a month, a 31.90% increase on a 625 kWh customer, and a 50.75% increase on a low usage 375 kWh customer. The threshold increase that would be considered rate shock was not established in this proceeding, but AE's Brian Murphy testified that an increase of 25.7% would constitute rate shock. Under this standard, it appears that AE customers consuming 625 kWh a month or less would experience rate shock under AE's new proposed rates.

AE argues that its proposed base rate design will mitigate seasonal rate shock, by decreasing volatility in electric charges from non-summer to summer.[650] AE points out that, on average, a residential customer's consumption increases by 342 kWh per month during the summer months, a 49% increase.[651] At the same time, higher levels of consumption during the summer

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[648] A review of the peer reviewed literature on this relationship would be helpful to evaluate this point. Such a review, however, is outside the purview of the IHE in this proceeding.
[649] ICA Brief at 3.
[650] AE Ex. 1 at 118.
[651] AE Ex. 1 at 118.

occur in tiers 4 and 5, where rates are higher.[652] Increased consumption coupled with higher pricing creates a situation where summer charges may be significantly higher for AE's residential customers as compared to non-summer charges. AE argues that by flattening the tiers and increasing the customer charge, the proposed rate design mitigates this problem. The Base Rate Package indicates that under the proposed base rates, the average swing from non-summer to summer would fall to 27%.[653]

The IHE finds that AE's proposed rate design would mitigate this particular sub-variety of potential rate shock. However, the IHE finds that this seasonal swing rate shock should be considered less of a concern than the overall rate shock discussed above. In part, this is because AE already maintains programs to mitigate the effect of seasonal swing rate shock, such as its budget billing program for residential customers.

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. However, as discussed below, what design to adopt depends heavily on City Council's policy preferences, and estimating the impact of such design will depend on number running that has not yet taken place and is outside the scope of the IHE's analysis.

E. Customer Charge

AE proposes to increase the customer charge from \$10 to \$25 to reflect fixed customer costs that do not vary with consumption.[654] AE contends that matching the customer charge to the customer unit costs will result in customer charge revenues directly tracking the underlying cost driver—the number of customers.[655] AE states that, despite this increase, its proposed customer charge is still less than the total combined customer and delivery costs suggested by the cost of service study.[656]

AE argues that the two overall considerations to limit the customer charge—protecting vulnerable customers less able to afford high fixed charges and promoting energy conservation

[652] AE Ex. 1 at 119.
[653] AE Ex. 1 at 119.
[654] AE Ex. 1 at 109.
[655] AE Ex. 1 at 111.
[656] AE Ex. 1 at 111.

with prices that respond to usage—are offset by AE's base rate design and other programs. In the first place, AE argues that the concern with protecting vulnerable customers is addressed by its CAP program, which waives the customer charge for CAP participants.

Comparisons to other Utilities for the Increase in AE's Customer Charge

In its Base Rate Package, AE justified its customer charge increase, in part, by identifying other utilities with comparable customer charges, such as Pedernales Electric Cooperative, Bluebonnet Electric Cooperative, and the City of Georgetown. Mr. Robbins and the ICA take issue with this comparison. Mr. Johnson notes that Pedernales and Bluebonnet Electric Cooperatives are not comparable since they are electric cooperatives serving rural areas; utilities of these types tend to have higher customer charges because of the longer service lines required and costs associated with serving lower population density. Because these factors are in sharp contrast to AE, he contends these utilities do not serve as a good point of comparison.[657] The IHE notes that rural electric cooperatives typically lack the customer density of an MOU, meaning they have fewer customers through which to recover the costs associated with a customer charge.

The ICA also notes that the only MOU AE used as a comparison, Georgetown, is 4% the size of AE, which may have an impact on its customer charge.[658] Mr. Johnson argues that AE should be compared to other MOUs that serve major metropolitan areas, such as San Antonio City Public Service (CPS Energy) and Lubbock Power & Light (LP&L), which each maintain a customer charge similar to, and lower than, AE's current customer charge.[659] Mr. Robbins also provided an alternative analysis of the customer charges of 10 of the largest Texas MOUs, finding that the average customer charge was $9.76, which is very similar to AE's existing charge.

AE argues that these analyses fail to take into account other factors, such as demographic trends in Austin, including high customer growth and shifts to smaller housing units. According to AE, revenue stability has taken on heightened importance and urgency because of these factors, and it is therefore appropriate for Austin's rates to differ from other MOUs in Texas.[660]

AE also argues that the participants' benchmarking analyses fail to account for how AE's CAP program compares favorably to assistance programs at other utilities. For example, AE

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[657] ICA Ex. 3 at 12.
[658] ICA Ex. 3 at 12. Mr. Robbins further attempts to distinguish Georgetown by noting that, unlike AE, it does not include a generation function, but he has failed to explain how this distinction affects the customer charge.
[659] ICA Ex. 3 at 12-13
[660] AE Ex. 9 at 39.

contends that CPS Energy fails to offer vulnerable customers equivalent relief from customer charges and more tightly curtails qualification at 125% of Federal Poverty Guidelines rather than AE's 200%.[661] CPS Energy requires the customer to apply for enrollment, whereas AE automatically enrolls customers who are already on certain federal, state, and local assistance programs.[662] AE asserts that LP&L does not appear to offer any assistance to vulnerable customers.[663] AE concludes that it is much more generous in its CAP program relative to CPS Energy and LP&L regarding the potential impact of its customer charge on vulnerable customers.

AE argues that participants' benchmarking analyses also fail to consider the utilities' mix of power production that is accomplished by fossil plants. AE notes that in 2021, only 28% of the power produced by AE came from carbon-based resources, whereas at CPS Energy and LP&L, it was twice as much.[664] Further, AE asserts that it has an aggressive plan to eliminate carbon-based generation. Under AE's current Climate Protection Plan, 86% of AE's electricity generation will be carbon-free by year-end 2025, 93% will be carbon-free by year-end 2030, and all generation resources will be carbon-free by 2035.[665]

Finally, AE argues that it is invalid to compare AE's proposed customer charge to other MOUs' customer charges to the extent that the comparison MOUs may have a declining block rate structure, while AE's base rate structure is an inclining structure.

The IHE notes that AE identified several factors distinguishing it from the other large MOUs with respect to customer charges. AE, however, failed to articulate why rural electric cooperatives or the comparatively tiny MOU serving the City of Georgetown would serve as better points of comparison. In responding to Mr. Robbins' and the ICA's criticisms of the increased customer charge, AE focuses on its CAP program because it waives the customer charge for qualifying customers. The IHE acknowledges that AE's CAP program appears to be more generous than that of CPS Energy and LP&L. However, every city is different and Austin is growing rapidly with an increasingly high cost of living. If AE's customer charge is approved, the IHE reiterates that some form of targeted program, like CAP, be implemented to assist those customers who do not qualify for CAP, but are nevertheless vulnerable to rate shock.

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[661] AE Ex. 9 at 36-37.
[662] AE Ex. 9 at 36-37.
[663] AE Ex. 9 at 36-37.
[664] AE Ex. 9 at 36-37.
[665] AE Ex. 9 at 38.

AE's Comparison to Investor-Owned Utilities

The ICA also argues that the customer charges of various Texas IOUs reveal that AE's proposed customer charge is an outlier.[666] The ICA states that AE's proposed residential fixed monthly charge would be $13 higher than the highest regulated customer charge in Texas.[667] The ICA calculates that the average IOU customer charge is only $7.44, and that even when restricted to bundled utilities like AE, the average is $9.77, comparable to AE's current charge.[668]

AE argues that this analysis should be disregarded because it compares "wires and poles" utilities like Oncor and CenterPoint to AE, a vertically integrated utility. AE points out that in areas open to competition, many of the customer-related services are provided by a separate retail electric provider (REP), and the costs of those services would not be included in the IOU's cost of service.[669] As a vertically integrated utility, AE serves the role of the REP, and incurs all the associated customer-related costs. The ICA maintains that the total cost difference that AE points to is negligible with respect to the customer charge, and so the comparison is valid.[670]

The IHE agrees with AE regarding comparisons to regulated wires and poles IOUs in ERCOT. Those utilities are subject to competition, meaning REPs have taken over a portion of the customer service functions. Those IOUs are not good comparators for AE, which limits the relevance of the ICA's analysis on this point.

Customer Charge Composition

The ICA further argues that AE's proposed customer charge is inflated beyond the proper requirements of the utility. The ICA contends that the residential customer charge should only recover costs that vary directly with the number of customers.[671] Generally, the costs that vary directly with customer count consist of meters, service lines, meter reading, and customer billing. Although AE asserts that the customer unit cost in its COS Study justify a 150% customer charge increase, the ICA counters that the unit cost in its calculation includes costs that are not directly associated with customers, and that do not vary with the number of customers.

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[666] ICA Ex. 3 at 8; ICA Brief at 37-38.
[667] ICA Ex. 3, Schedule CJ-5.
[668] ICA Ex. 3 at 58.
[669] AE Ex. 9 at 39.
[670] ICA Brief at 37.
[671] ICA Brief at 38 & n.135 (citing Docket No. 22344, Generic Issues Associated with Applications for Approval of Unbundled Cost of Service, Order No. 40 at 6, Interim Order Establishing Generic Customer Classification and Rate Design, "Specifically, the customer charge shall be comprised of costs that vary by customer such as metering, billing and customer service.").

The ICA contends that the customer unit cost includes a portion of what the ICA characterizes as general overhead costs, such as A&G expense and general plant, which do not vary with changes in the number of customers. The ICA points out that the COS Study also layers part of GFT, non-utility operations expense, and internally generated funds for construction onto the customer charge.[672] The ICA also challenges as improper AE's proposal to recover all uncollectible expenses through the customer charge. The ICA points out that this expense is not driven by the number of customers, but the size of unpaid customer bills, the largest proportion of which are energy charges.[673]

The ICA calculates that, if the customer charge were set to only collect costs related directly to the number of customers,[674] the appropriate charge would be only $6.11.[675] The ICA asserts that its calculation is created according to the "Basic Customer Method," and cites the RAP CAM's conclusion that this method is the most equitable way to set the customer charge for the vast majority of electric utilities.[676] SCPC/SUN echoes this observation, challenging the proposition that capacity costs should be properly recovered through customer charges.[677]

AE responds by noting that the costs the ICA identified do not vary with energy use. As a result, AE argues that recovery through kWh charges is no more consistent with cost causation principles than recovery through customer charges.[678]

Finally, the ICA argues that when customer charges are limited to the categories it identified, perhaps not even the current $10 charge is supported. The ICA, however, suggests that the customer charge should not increase more than the proportionate increase of revenue to be collected from the residential class, and accordingly proposes a maximum customer charge of $13.[679]

SCPC/SUN proposes that City Council should direct AE to retain its existing residential rate base schedule until it can develop and file an alternative rate plan that retains the current plan's

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[672] AE Ex. 1 at Schedule G-5 and G-6; ICA Ex. 12.
[673] ICA Ex. 3 at 61.
[674] According to Mr. Johnson, this would include 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, and would include a portion of pensions and benefits associated with the O&M expense. ICA Ex. 3 at 60.
[675] ICA Ex. 3 at 60.
[676] ICA Ex. 3 at 60; Regulatory Assistance Project "Electric Utility Cost Allocation for a New Era" at 145 (2020).
[677] SCPC/SUN Ex. 3 at 10-11
[678] AE Ex. 9 at 42-3.
[679] ICA Ex. 3 at 64.

benefits but is less disruptive and harmful to customers.[680] However, it also endorses the ICA's proposed $13 maximum customer charge, as does 2WR.

AE criticizes the ICA proposal as arbitrary. It argues that the ICA's recommendation proposes no change to the proportion of revenues collected under the fixed versus the variable charges, ignoring the driving factor in AE's declining financial stability. AE argues that maintenance of the existing rate design is not reasonable because it has contributed to the undermining of AE's financial health and resulted in inadequate cost recovery from low-usage customers.

The IHE acknowledges that AE's customer charge is composed of some expenses that do not vary with the number of customers, like the uncollectible expenses for some unpaid energy charges. AE provided evidence that the costs the ICA and SCPC/SUN oppose do not vary with energy use. As a result, the IHE recommends that it is reasonable to recover those expenses in the customer charge.

Conservation Concerns

SCPC/SUN argues that AE's proposal to move to a higher fixed charge and lower variable charges disincentivizes beneficial energy use practices and increases payback times for customer investments in energy efficiency measures or distributed energy resources, because the customers see less financial benefit for these investments.[681] SCPC/SUN also contends that this change penalizes customers who have already invested in energy efficiency measures, as well as raising bills for other low-usage customers.[682] SCPC/SUN observes that while AE's proposed customer charge may improve revenue predictability and lower risks for the utility, it does so at a significant net societal cost by disincentivizing conservation practices.[683] The ICA also argues that by moving revenue recovery from kWh energy charges and into a fixed customer charge, AE will shift revenue from rate elements that send price signals for conservation and energy efficiency to rate elements that send no such signals.[684]

AE responds that the ICA's recommendation keeps the customer charge below-cost while retaining steeper tiers, making energy-efficiency investments seem more attractive to customers

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[680] SCPC/SUN Brief at 11.
[681] SCPC/SUN Ex. 3 at 12.
[682] SCPC/SUN Ex. 3 at 12.
[683] SCPC/SUN Ex. 3 at 12.
[684] SCPC/SUN Brief at 11.

who are calculating bill savings. AE's concern is that a customer could be financially harmed if the customer charge is deflated and energy rate is inflated, because the customer could make an uneconomic investment in energy efficiency.[685]

AE also criticizes the contention that a high customer charge would harm energy conservation and penalize consumers who have undertaken conservation measures. AE argues that, in setting the customer charge to the unit cost, AE's proposal has no effect on the energy-related costs and the demand-related costs that are targeted for avoidance via energy efficiency programs.[686] AE states that under its rate design, most residential costs would continue to be recovered under energy rates, and a customer who invests in energy efficiency would continue to see significant bill savings from lowered consumption.[687] AE claims its proposal to set the customer charge to cost is superior from the standpoint of economic efficiency, because it mitigates the financial harm from inflated energy charges.

Finally, AE argues that conservation concerns are addressed because it has proven that its base rate structure has little to no effect on energy conservation. AE also argues that conservation concerns are addressed through its VoS program, as well as separate resource generation and climate-protection planning functions outside of the base rate review process.[688]

The IHE recommends that, if AE's customer charge increase is approved, AE has offered evidence that it will not disincentivize conservation. However, if City Council adopts the IHE's recommendation that AE's rate design be revisited, the IHE notes that AE's recent history reflects conservation goals as part of its mission. Those goals – under a more steeply tiered system – appear to be reflected in the decline in average residential consumption of 13% since 2013.

IHE Recommendation

The IHE is concerned that AE's proposed 150% customer charge increase will result in rate shock for some residential customers. However, the IHE finds that AE's concerns of financial stability are well founded, regardless of whether AE implements its proposed customer charge or adopts a more sharply tiered rate structure. In either case, the IHE recommends that the policy considerations of conservation, gradualism, and affordability be observed.

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[685] AE Ex. 9 at 44-46.
[686] AE Ex. 9 at 48.
[687] AE Ex. 9 at 52.
[688] AE Ex. 9 at 35.

F. Tier Structure

Background for AE's Proposed Tier Structure

Currently, the majority of residential customers that reside within the City are billed for energy use on a five-tier structure with each tier priced progressively higher. According to AE, the first and second tiers are priced below cost, meaning more than 40% of residential customers are priced below cost.[689] AE contends that there are simply not enough customers with consumption in the higher tiers to make up the revenue deficit from the lower tiers' under-recovery.

AE contends this is exacerbated by the fact that high-use customers are gradually retiring from the system, and that growth in sales is occurring primarily in the lower tiers.[690] The Base Rate Package states that in FY 2021, 76% of residential energy sales occurred in Tiers 1 and 2, in the consumption blocks below 1,000 kWh.[691] AE argues that the disappearance of energy sales from higher-priced tiers and the concentration of sales in the tiers priced below cost of service are two of the factors that have caused the residential class to drift further away from cost of service since the last rate review.[692] AE argues that lower energy consumption is not largely a result of the current rate structure's price signals, but rather changes in technology, building codes, and housing density in the interim, along with a large amount of new residential construction and population growth.

AE's Proposed Tier Structure

AE proposes a new residential base rate structure designed to capture the changing composition of the residential customer class, relying more heavily on cost recovery in the initial, lower consumption, tiers. AE proposes to modify the residential base rate structure by reducing the number of tiers and sharply flattening the steepness of the rate increases between each tier.

Under AE's proposal, the number of tiers is reduced from five to three, and the tier breakpoints are adjusted downward; AE states this is designed to match the shift in the bill frequency distribution towards lower levels of consumption.[693] New Tier 1, from 0 to 300 kWh, reflects low customer consumption and is set slightly below the cost of service AE (derived as demand-related costs divided by kWh).[694] New Tier 2, from 301 to 1,200 kWh, reflects the typical

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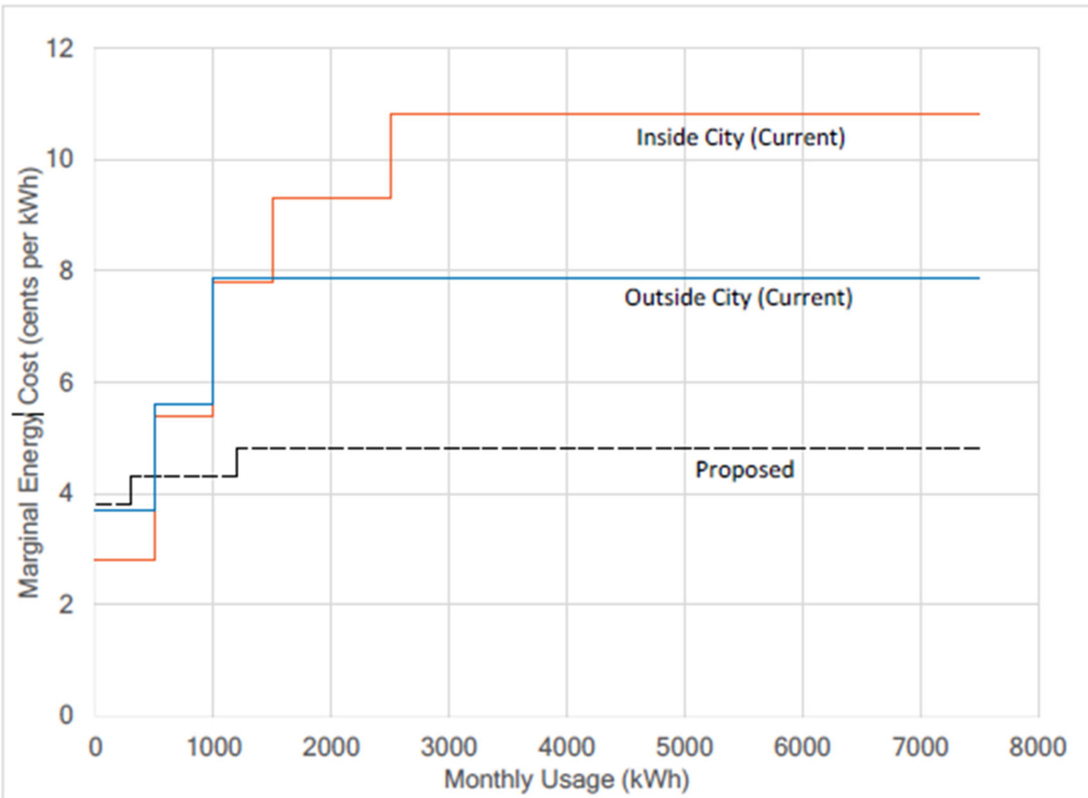
689 AE Ex. 3 at 12, *citing* AE Ex. 1 at 289.
690 AE Ex. 1 at 103.
691 AE Ex. 1 at 103.
692 AE Ex. 1 at 105.
693 AE Ex. 1 at 110-111.
694 AE Ex. 1 at 110-111.

residential customer.[695] New Tier 3 is for usage above 1,200 kWh, which represents higher usage customers, and this rate is set slightly above cost of service.[696] Under the proposal, AE estimates that approximately 34% of consumption would occur in the first tier, 50% of consumption would be in the second tier, and the remaining 16% of consumption would occur in the third tier.[697]

In addition to reducing the number of tiers and adjusting the kWh thresholds, AE proposes a price structure that dramatically flattens the tiers. The IHE found a visual representation of this revision, provided by SCPC/SUN expert Dr. Hausmann, instructive:[698]



As this table shows, the price per kWh in the proposed rates structure varies little across the three tiers, compared to the current structure.

Overview: Response to AE's Proposed Tier Structure

Several participants take issue with AE's proposed redesign of the current five-tier base rate structure. Generally, the participants propose to either: (1) leave the current rate design unchanged; (2) direct AE to develop a new proposal; or (3) make a more moderate change to the

[695] AE Ex. 1 at 110-111.
[696] AE Ex. 1 at 110-111.
[697] AE Ex. 1 at 110-111.
[698] SCPC/SUN Ex. 3 at 18, fig. 2.

current base rate design.[699] AE argues that these proposals are inappropriate. AE notes that the current residential base rate design is based on a 2009 test year, when residential consumption patterns were different, rendering the rate design ineffective for the present circumstances.[700]

AE claims that the reduction of tiers creates a simpler, more equitable rate structure, and addresses the purported inability of tier subsidization to accomplish revenue stability.[701] AE claims that its significant adjustments to the consumption levels of the three tiers better reflect current customer usage patterns.[702]

AE argues that changes in consumption patterns necessitate a change in the tier structure. According to AE, the energy efficiency gains achieved by residential customers since 2009 have changed what a high-use customer is for AE, and that more customers are using less electricity than when the current rate structure was designed. The compound annual growth rate in the consumption between 2012-2021 shows consumption reductions in Tiers 3 to 5 and consumption gains in Tiers 1 and 2.[703] AE observes that 76% of residential energy sales in FY 2021 occurred in Tiers 1 and 2. AE notes that most of the growth occurring in Austin is in multi-family housing. AE contends that new construction is twice as energy efficient as older units and that, on average, multi-family units consume half the energy of single-family homes.[704] AE considers this pattern as both a reason for the declining consumption and an indication that the trend is likely to continue.

Mr. Robbins contends that there are several problems with AE's declining consumption analysis and its explanations for the causes of reduced consumption. He argues that AE's analysis fails to: (a) account for customers who have their HVAC needs met with a central system; (b) consider that customers in older dwellings will also become more efficient over time by updating appliances; and (c) consider how consumption in rental units in the study might be influenced by CAP customer consumption.

The IHE's finds Mr. Robbins' criticism insufficient to fully address or overcome AE's analyses concerning declining consumption. Further, Mr. Robbins did not quantify his criticisms, leaving the IHE uncertain of the impact of the factors he identifies in AE's evidence of declining residential consumption.

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699 AE Ex. 3 at 9.
700 AE Ex. 3 at 9.
701 AE Ex. 3 at 10-11.
702 AE Ex. 3 at 11.
703 AE Ex. 1 at 102.
704 AE Ex. 1 at 104.

Conservation Price Signals

SCPC/SUN argues that, while AE may describe its proposal as a three-tiered structure, it would be very close to a flat rate structure. As shown above, SCPC/SUN illustrated the flatness of AE's proposed structure relative to the existing structures for both inside-city and outside-city customers.[705] SCPC/SUN also argues that under AE's proposal, 60% of AE's customers would be in the low central tier, and all tires, including those with the highest usages, would have weak price signals to conserve.[706] SCPC/SUN further observes that at 4.8 cents per kWh, even the highest-priced tier is 18% below the current price in Tier 2 of 5.8 cents per kWh.[707] SCPC/SUN concludes that, under AE's proposed rate design, the price signals that are designed to encourage conservation would be effectively eliminated.[708]

As discussed above in Section V.D. regarding gradualism, the ICA argues that AE's tier proposal would impose large cost increases on low usage residential customers. SCPC/SUN points out that according to testimony from AE's own witness Genece, AE's redesigned rate tiers (along with the increased customer charge) would cause the average distributed solar generator's electric bill to double.[709] Both ICA and SCPC/SUN argue that the tier redesign would unfairly impact low use customers, disrupting the conservation price signal and interfering with the expectations of the those who had previously invested in energy efficiency measures.

AE responds that under its proposed rate design, high use customers who use more energy will continue to have higher bills, preserving the price signals sent to customers.[710] AE argues that the current inside-city, five-tier residential base rate structure creates price distortion by sending incorrect pricing signals, resulting in poor economic decisions for both high and low use customers.[711] The ICA argues that it is inappropriate for AE to use the COS Study to draw conclusions on intra-class customer cost causation, since the tool is only intended to estimate costs for overall customer classes.[712]

The IHE finds that, while some price signal is preserved, the effect of the tier change redesign may dampen conservation price signals. Furthermore, AE's characterization of the

[705] SCPC/SUN Ex. 3 at 18, fig. 2.
[706] SCPC/SUN Ex. 3 at 16-21.
[707] SCPC/SUN Ex. 3 at 17.
[708] SCPC/SUN Ex. 3 at 17.
[709] SCPC/SUN Brief at 19, *citing* AE Ex. 7 at 11.
[710] AE Ex. 3 at 11.
[711] AE Ex. 3 at 11.
[712] ICA Ex. 3 at 74.

current rate structure as creating price distortion and sending incorrect signals, resulting in poor decisions, appears to assume that the primary goal of the rate structure is to match prices with cost causation. A tier system designed to send conservation price signals may depart from pricing on cost causation. The IHE considers the issue of whether rate design should focus more on cost causation versus sending conservation price signals to be a matter of policy. Similarly, the IHE views the strength of the price signal, as represented by a steeper tier structure (as well as the proportion of revenue obtained through tiered energy pricing as opposed to a customer charge) is also a policy decision.

Finally, as explained above, AE argues that customers do not respond to tiered pricing signals, with neither the number of tiers nor the incline of the tiers having much effect on conservation decisions.[713] The IHE, however, was not persuaded by AE's conclusion on this issue.

Impact on Low Usage Customers; ICA's Proposal

The ICA proposes an alternative tier recommendation. The alternative proposal includes an intermediate four tier design, with tiers at 0-500 kWh, 500-1300 kWh, 1300-2500 kWh, and >2500 kWh. The proposal includes a marginal energy cost design that resembles the current tier pricing steepness, rather than the flattened tiers AE proposes. For example, the first tier would be priced at 0.030, the second at 0.065, the third at 0.097, and the fourth at 0.119.[714]

AE responds that its tier redesign does not unfairly impact low usage customers. AE contends that the majority of inside-city residential customers not in CAP in the first residential tier range from 90% to 183% below cost of service.[715] According to AE, this correlates to more than 40% of residential customers being subsidized.[716] AE argues that the proposals put forth by the ICA and SCPC/SUN are inconsistent with current customer usage, continue subsidies within tiers, are not based on cost, and do not provide fair and equitable rates.

AE concludes that these proposals are not fair—they just reduce costs to low-usage customers and shift their cost responsibility to high usage customers, who are already (1) paying well above cost and subsidizing their low usage neighbors, and (2) charged more for their higher energy usage, resulting in higher bills. AE claims that this is inconsistent with accepted ratemaking

[713] AE Ex. 1 at 87-95.
[714] ICA Ex. 3 at 72-73. The specific kWh charges would need to be adjusted based on the numbers run when with any revenue requirement, cost allocation, and class revenue distribution adjustments made. These were produced by Mr. Johnson assuming a $12 customer charge and adoption of the AE revenue requirement.
[715] AE Ex. 3 at 12.
[716] AE Ex. 3 at 12.

principles, and threatens AE's financial stability. These arguments have been addressed in the above sections on financial stability, fairness, affordability, and gradualism.

IHE Recommendations

The IHE shares the ICA's concern that AE's proposed flattened tiers may, even if AE's approach to gradualism is adopted, result in rate shock for economically vulnerable customers. The IHE is also concerned, albeit to a lesser degree, that the tier structure may dampen conservation signals as argued by SCPC/SUN.

Regarding the adoption of a tier design proposal, the IHE notes that there are a number of options for City Council to consider, depending on its policy choices. If City Council adopts AE's proposed tier redesign, the IHE believes that this would likely reduce seasonal volatility and provide greater financial stability to AE as residential consumption continues to decrease. If, however, City Council adopts a tier structure similar to the ICA recommendation, it could alter the existing structure, preserve a stronger conservation price signal, and avoid intra-class rate shock for low usage customers. Finally, City Council could adopt the IHE's recommendation that AE work with the participants to develop a tier structure that better protects economically vulnerable customers, or in the alternative, develop a targeted customer assistance program like CAP for those customers.

The IHE notes that AE's concerns over under-recovery of revenue from the residential class may be addressed by increasing the kWh rates across the tiers under the ICA's proposed structure or even the existing rate structure. However, the potential for rate shock on the higher-consuming residential customers under these scenarios has not been fully examined. As an alternative to adopting the ICA's proposed tier system or AE's proposal, City Council may wish to direct AE to calculate proposed kWh hour rates for each tier of residential customers under a variety of tier scenarios after numbers are run. At that point, 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.

G. Outside-City Customer Rate Differential

AE also proposes to eliminate the base rate distinction between inside- and outside-city customers such that there will be a single rate structure for both.[717] Currently, outside-city

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[717] AE Ex. 1 at 110.

customers are charged according to a different rate structure, with only three tiers, that sends less of a conservation price signal than the inside-city five-tier rate, and presumably, involves less of what AE considers an intra-class subsidy between the tiers.

The ICA argues that, if AE's proposed rate design is adopted, this will result in a 26% increase in revenue collected from inside-city customers, while granting a 7.4% reduction in the revenue collected from outside-city customers. According to the ICA, these results are a consequence of AE's rate structure changes and its decision to eliminate a separate tariff for outside-city residential. The ICA argues that housing stock, residential density, and energy use per customer outside the city differs from inside-city residential customers.[718] The ICA notes that, on average, outside-city residences use 86% more electricity than inside-city customers.[719] The ICA reiterates that the 26% revenue increase to inside-city residential customers is higher than the 25.7% class increase which AE witness Murphy admitted constitutes rate shock.[720]

Given the differences in usage characteristics, the ICA recommends leaving the outside-city residential tariff unchanged. The ICA notes that this will eliminate AE's proposed revenue reduction for outside-city customers. The ICA argues that AE can provide no cost information which supports a significant change in outside city residential rates. Absent data regarding the coincident and non-coincident demands of outside city customers, the ICA argues that positions on the cost of serving those customers are mere speculation.

AE responds that no evidence supports the ICA's theory that AE's proposed single residential base rate structure is unfair to inside-city residential customers. AE argues that the ICA's proposal demonstrates an apparent preference for subsidization of inside-city residential customers by outside-city residential customers.[721] AE further argues that leaving outside-city residential customers unchanged would violate cost causation principles.[722] AE opposes the ICA's proposal to maintain separate base rates for outside-city customers.

If City Council approves AE's proposed rate structure, the IHE recommends that the same rates should not apply to both inside- and outside-city customers. The ICA presented evidence that housing stock, residential density, and energy use per customer outside the city differs from inside-

[718] ICA Ex. 3 at 68.
[719] ICA Ex. 3 at 69.
[720] AE Ex. 9 at 13.
[721] AE Ex. 3 at 32.
[722] AE Ex. 3 at 32.

city residential customers. Specifically, the ICA provided evidence that, on average, outside-city residences use 86% more electricity than inside-city customers. Despite the higher average energy use, under AE's same-rate proposal, outside-city customers would receive a rate reduction. If AE's rate design is approved, the IHE recommends either a different rate structure be developed or that the ICA's proposal be adopted.

If, however, City Council adopts the IHE's recommendation that AE and the participants work to develop a different rate design, then the IHE recommends that the parties revisit this issue, keeping in mind the distinctions between inside-city and outside-city customers addressed above. The IHE also notes that the parties will need to implement City Council's policy decision on whether to apply GFT cost recovery to outside-city customers.

H. Commercial and Industrial Base Rate Design and Rates

AE has proposed several general adjustments to the base rate design for commercial and industrial customers. These changes include increasing fixed charges, eliminating the billing-unit adjustment that currently benefits low-load factor commercial customers, calculating the billing demand for houses of worship customers the same as other commercial customers, establishing consistency in recovery of discounts for State accounts and independent school districts accounts by assigning this cost responsibility to all non-lighting classes in proportion to cost of service, and combining the current electric delivery charges with the demand charges. AE has also proposed base rates for all non-residential and non-lighting customer classes, summarized in Table 7-K of the RFP.[723]

No participant has raised issues with AE's proposed changes to the base rate design or base rates for these customer classes. The IHE has not evaluated these unchallenged proposals.

I. Proposed Tariff

AE included a copy of its proposed Tariff in Appendix F of the Base Rate Filing Package.

VI. Value of Solar

A. IHE Recommendation Summary

AE proposes to change its VoS rate design in the three following ways: (1) breaking down the VoS into the three pillars of avoided costs, societal benefits, and policy-driven incentives;[724] (2) funding the VoS through the PSA and the EES component of the CBC;[725] and (3) using a

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[723] AE Ex. 1 at 125-127.
[724] AE Ex. 1 at 140.
[725] AE Ex. 1 at 143-145.

backward-looking, as opposed to a future-looking methodology to determine the VoS.[726] The IHE finds that the AE-proposed VoS creates transparency in the costs and values associated with the VoS rate, the new approach aligns recovery of the VoS with an appropriate rate mechanism, and moving from a marginal cost basis to an embedded cost basis for the avoided cost component of the VoS is appropriate. The IHE also finds that AE's proposed VoS provides fair compensation for measurable benefits that solar customers create for AE and the community. While distributed solar customers' energy bills may increase, the proposed methodology results in an increase to the VoS rate (or credit) for all customer classes relative to the current VoS rate. Accordingly, AE has met its burden to demonstrate its proposed approach is just and reasonable. However, the IHE recognizes SCPC/SUN's assertions that stakeholder involvement in determining the VoS tariff was lacking, and thus recommends that AE consider ways to increase community and stakeholder participation in the evaluation process in the future.

For the reasons outlined below, the IHE recommends that the VoS be calculated in accordance with AE's recommendation. However, the IHE recommends: (1) AE evaluate opportunities for additional public and stakeholder input in future VoS determinations, and (2) AE more clearly define what comprise the "rates, methodology, and inputs" that must be reassessed consistent with AE's VoS tariff.

B. Background

AE explains that pursuant to its VoS tariff, its VoS rates, methodology, and inputs must be reassessed and updated whenever AE performs a rate review using the calculations outlined in the tariff. As a result, AE contends that this Base Rate Review is appropriate for reconsideration of the VoS rates pursuant to the tariff's requirements.

The VoS is the rate through which AE credits residential and commercial customers with behind-the-meter solar generation systems for the energy their systems produce.[727] AE explains that a customer's monthly electricity bill includes a charge for the total energy usage of their home or business for the billing period, and that the charge is then offset by the solar credit for the energy that customer's system generated at the applicable VoS rate. AE further explains that solar credits are only applicable to the electric bill, they cannot be used to offset other City charges, and solar

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[726] AE Ex. 1 at 140.
[727] AE Ex. 1 at 138.

credits that exceed the electric portion of the monthly bill roll over to the following month, as long as that customer account remains open.

AE states it has identified components of the VoS rate calculation that no longer align with AE's underlying costs, but these components have historically been included in the calculation of the VoS rate. As a result, AE proposes a new approach for its VoS rate design that addresses these components, and that is intended to be more transparent and flexible. AE states that with the new approach, it hopes to achieve a rate design that fairly compensates customers for their onsite renewable energy production and adequately stimulates customer-sited solar adoption to help meet the City's Resource Generation and Climate Protection goals. Further, AE asserts the goals of the new approach to the rate design are three-fold: (1) to create transparency by making clear delineation between the values used to impute VoS; (2) to align recovery with the most appropriate rate mechanism; and (3) to move from a marginal cost basis to an embedded cost basis for the avoided cost component of the VoS.[728] According to AE, the new methodology more accurately allocates costs in accordance with standard utility ratemaking practices.

C. Proposed Changes to Approach

AE proposes three changes to the VoS program. The first change is to separate the VoS concept into the following three pillars: avoided costs, societal benefits, and policy-driven incentives.[729] The second change is to fund the VoS through the PSA *and* the EES component of the CBC, as opposed to the funding the VoS solely through the PSA.[730] The third change is to determine the VoS rate using a backward-looking methodology, as opposed to the future-looking method that AE currently employs.[731]

To support the first proposed change, AE contends the VoS is an aggregated value that includes marginal costs, avoided costs, and environmental costs, so disaggregating the value into the three identified pillars increases transparency.

In support of the second proposed change, AE argues that, while it is appropriate to recover the avoided costs of purchased power through the PSA (one of the three pillars of the VoS), it is

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[728] AE Ex. 1 at 16.
[729] AE Ex. 1 at 140.
[730] AE Ex. 1 at 143-145.
[731] AE Ex. 1 at 140. AE asserts it will conduct an annual assessment of each pillar to ensure the prevailing rates are consistent with market conditions, environmental reports, and policy objectives. In addition, AE intends to hold a public meeting with each reassessment, present the findings to the City's EUC and Resource Management Commission (RMC), and seek City Council approval prior to implementation. AE Ex. 1 at 140.

not appropriate to recover the societal benefits and policy-driven incentives through the PSA, because these are not avoided purchased power costs. AE argues the societal benefits and policy-driven incentives pillars should instead be recovered through the EES component of the CBC, which is where other similar program costs, such as rebates and other solar incentives, are recovered. AE argues this approach would clearly differentiate the avoided cost of rooftop solar power from its societal costs and other subsidies.[732]

In support of the third change, AE asserts calculating the avoided cost component on an embedded historical cost basis (backward-looking methodology) as opposed to a marginal cost basis that relies on estimated future costs (forward-looking methodology) is preferable because the embedded cost basis relies on actual documented expenses. The forward-looking approach, which has historically been used to determine the VoS rate, is calculated based on marginal cost avoidance and includes an environmental adder in addition to avoided costs to the utility.[733] AE contends that calculating the avoided cost of the VoS through the PSA would be consistent with the approach it takes with its other rates, including its power supply costs, which are collected through the PSA.[734] AE further argues that the new approach achieves the goal of promoting transparency by making clear delineations within the VoS rate and by aligning the justifications with the most appropriate rate mechanisms.[735]

In opposition to AE's proposed approach, SCPC/SUN raises concerns that (1) AE's avoided cost calculation ignores avoided costs associated with system capacity, reserve generation, and distribution capacity (and thus AE is crediting solar customers with only the avoided cost of energy);[736] (2) proceeding with the proposed VoS tariff makes customers less likely to invest in solar generation (because it suppresses the credit);[737] (3) AE's proposed approach transforms the tariff for distributed solar generators from a forward-looking calculation to a backward-looking one, based primarily on wholesale avoided costs without accounting for certain recognized and quantifiable items, such as reductions in pollution from fossil generation and distribution system savings; (4) AE's proposed rate structure may not be just and reasonable;[738] and (5) stakeholder

[732] AE Ex. 1 at 143-145.
[733] AE Ex. 1 at 138.
[734] AE asserts that by implementing the three proposed VoS changes, AE will continue to be a national leader in the development of solar, demand-side management, and renewable energy initiatives.
[735] AE Ex. 1 at 140.
[736] SCPC/SUN's Brief at 1; SCPC Ex. 2 at 21.
[737] SCPC/SUN Ex. 2 at 21; SCPC/SUN's Brief at 27.
[738] SCPC/SUN Ex. 2 at 5.

input in the VoS determination is lacking. In sum, SCPC/SUN contends that AE's development of the new VoS tariff was procedurally defective and the resulting tariff discriminatory and unreasonable for the reasons described above.[739]

AE refutes SCPC/SUN's assertions that the proposed avoided cost calculation ignores avoided costs associated with system capacity, reserve generation, and distribution capacity. AE points out that, even at times when a solar customer's generation system is not producing, such customers still require distribution infrastructure to serve them, and they use the distribution system to deliver their excess production onto the grid.[740]

AE responds to SCPC/SUN's suppression of credit concerns, by pointing out that AE proposes to increase the VoS credit over the current value, as well as over the calculated value using the current methodology for test year 2021. AE argues that the proposed approach is not a suppression of the credit, because it results in increases to the VoS for all customer classes relative to the current VoS rate. AE also argues that its proposed approach, which bases the VoS components on the past fiscal year, ensures a more accurate reflection of the actual, realized value of distributed generation to the customers and system.[741] In response to SCPC/SUN's argument that "numerous jurisdictions have used true Value of Solar analyses to inform and support net metering and related customer generation rate decisions,"[742] AE points out that it rejected net metering because net metering credits would be considerably less per kWh.

After considering the elements of AE's new VoS methodology, the IHE is not persuaded that the development of the approach was defective or that it results in a discriminatory or unreasonable VoS tariff. The pillars of AE's new VoS approach are addressed in more detail below.

D. Avoided Costs

1. Calculation Methodology

The first pillar of the VoS is the avoided costs component. AE proposes calculating avoided costs by focusing on the embedded costs that can be avoided by behind-the-meter solar generation

[739] SCPC/SUN's Brief at 22-27.
[740] AE Ex. 7 at 12.
[741] AE Ex. 1 at 143; AE Ex. 7 at 8.
[742] SCPC/SUN Brief at 28.

systems.[743] The avoided cost value is composed of the following three components: (1) ERCOT Energy Savings;[744] (2) Transmission Savings;[745] and (3) Ancillary Service (AS) Savings.[746]

According to AE, this methodology bases the value components on the past fiscal year, which AE argues is a more accurate reflection of the actual, realized value of distributed generation.[747] AE maintains this is an objective, non-outcome-driven analysis, that is based on avoided costs that accurately reflect the true benefits of solar customers to the system.[748] AE affirms the avoided costs would be reevaluated annually.[749]

SCPC/SUN challenges AE's proposed avoided costs calculation for the VoS. SCPC/SUN asserts that AE is crediting solar customers with only the avoided cost of energy.[750] AE responds that its proposed VoS includes credits associated with avoided costs, societal benefits, and policy driven incentives. SCPC/SUN also asserts that under AE's proposal the avoided cost component would be calculated based on the previous year's average day-ahead price for ERCOT system energy and a fixed, nominal credit for transmission and ancillary services.[751] AE also rejects this argument. AE clarifies that transmission and ancillary service values in AE's proposal are neither fixed nor nominal.

Finally, SCPC/SUN claims that AE is proposing to "to slash its Value of Solar."[752] In response, AE points out that it is proposing increases to the VoS rates over the current value as well as over the calculated value using the current methodology for test year 2021.[753]

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[743] AE Ex. 1 at 140-141.
[744] The ERCOT Energy Savings element is based on the weighted average price for energy at the time of photovoltaic (PV) generation and is calculated as the sum of the Austin Energy Node (AEN) day-ahead price for each hour in the year multiplied by the PV generation for that same hour divided by the total PV generation. AE Ex. 1 at 141.
[745] The Transmission Savings component is based on average PV generation during the ERCOT 4CP periods multiplied by the ERCOT postage stamp rate (the sum of the individual wholesale transmission service charges billed by each transmission service provider in ERCOT) divided by the total PV generation. AE Ex. 1 at 141.
[746] The AS Savings component is based on the weighted average price for AS at the time of PV generation. ERCOT has four ancillary service products currently that support the transmission of energy to loads and the reliable operation of the bulk electric system. These four products are Regulation Service – Up (REG UP), Regulation Service – Down (REG DOWN), Responsive Reserve Service (RRS), and Non-spinning Reserve Service (NSRS). The AS Savings is calculated as the sum of the Scaled AS Price (the sum of the four different ancillary service products in each hour scaled to its relevant proportion with overall ERCOT energy load) for each hour multiplied by the PV generation for that same hour divided by the total PV generation. AE Ex. 1 at 141-142.
[747] AE Ex. 1 at 143.
[748] AE Ex. 7 at 8.
[749] AE Ex. 1 at 143.
[750] SCPC/SUN Brief at 1.
[751] SCPC/SUN Brief at 1.
[752] SCPC/SUN Brief at 1.
[753] AE Ex. 1 at 148.

The IHE recommends approval of AE's proposed calculation method. Despite SCPC/SUN's claims, it is fundamental to AE's VoS that it include credits associated not only with avoided costs, but also societal benefits, and policy driven incentives, as discussed below.

2. Recovery Method

AE maintains that because it is crediting solar generation customers for their renewable energy contribution, the avoided cost component of the VoS will be recovered through the PSA. AE states this pillar will be calculated based on the ERCOT Energy Price, Transmission Savings, and Ancillary Service Price. The PSA charge recovers the net cost of kWh used by customers, including the cost of electricity purchased from the grid and any net revenues (or losses) experienced as AE produces and sells power to the grid.[754]

E. Societal Benefits

1. Background

The second pillar is the societal benefit component. AE determined that several federal departments, including the U.S. Department of Energy and the U.S. Environmental Protection Agency, began regularly incorporating the social cost of carbon (SC-CO2) estimates into benefit-cost analyses beginning in 2008. AE proposes a similar approach to determining the societal benefits value that avoiding a kWh on the ERCOT grid captures.[755]

2. Calculation

To calculate the societal benefit value moving forward, AE proposes to reference the social cost of carbon (SC-CO2 average value) at a 3% discount rate.[756] The year that the rate will go into effect will be the Emissions Year referenced in Table 9-D of AE's Ex. 1, and will be used to determine the value per metric ton of CO2.[757] That value is then multiplied by the amount of CO2 avoided according to the U.S. Energy Information Administration's Texas specific State Electric Profiles report.[758]

SCPC witness, Mr. Rábago, expressed concern that the societal benefit value does not include the societal benefits of avoiding a wide range of air-borne pollutants.[759] AE responds that the societal benefit portion of the VoS is based on the societal cost of carbon and the avoided

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[754] AE Ex. 1 at 143.
[755] AE Ex. 1 at 144.
[756] AE Ex. 1 at 144-145.
[757] AE Ex. 1 at 144.
[758] AE Ex. 1 at 144-145.
[759] SCPC/SUN Ex. 2 at 8-9.

metric tons of CO_2/MWh based on the Texas energy mix.[760] AE asserts that its proposal bases that value on carbon, in alignment with the objectives of the AE Resource, Generation and Climate Protection Plan to 2030, and also in alignment with the City's overall climate goals.[761]

The IHE agrees with AE that the societal benefit value addresses airborne pollutants, even if the focus is on CO_2. Furthermore, AE provided evidence that the societal benefit value is consistent with AE policy and the City's climate goals.

3. Recovery Method

AE argues that while the entire VoS, including environmental benefits, was historically recovered through the PSA, the societal benefit value does not represent an avoided cost to AE. As such, AE believes this cost should instead be recovered through the EES portion of the CBC going forward. AE argues that, while it is appropriate to recover the avoided costs of purchased power through the PSA, it is not appropriate to recover the societal benefits and policy-driven incentives through the PSA because these are not avoided purchased power costs. Instead, AE posits, the societal benefits and policy-driven incentives pillars should be recovered through the EES, which is where other similar program costs, such as rebates and other solar incentives, are recovered.

SCPC/SUN expressed concerns that the recovery of VoS societal benefits through the EES charge will reduce the amount of funding available for other EES programs.[762] AE responds that its annual proposed budget, as approved by the City Council, provides the cost basis for determining the EES factors being charged to customers. AE explains that this budget process is open to public participation and is the starting point for determining the amount of funds that will be available for funding EES programs. Additionally, AE asserts there are multiple other settings where the public may weigh in on budgets and programs, such as the monthly EUC and Resource Management Commission (RMC) meetings. AE states the EES budget is not determined by the EES charges; the EES charges are determined by the EES budget.[763]

Further, AE states there is no proposed reduction to the EES budget in the FY 2023, which is within the Consumer Energy Solutions (CES) budget. Instead, AE notes that the CES budget for

[760] AE Ex. 7 at 9.
[761] AE Ex. 1 at 144-145.
[762] SCPC/SUN Ex. 1 at 6.
[763] AE Ex. 7 at 8.

FY 2023 proposes an increase over the current CES budget for FY 2022.[764] AE argues that contrary to criticism, a more accurate and transparent method of paying for societal benefit portion of the VoS will not result in necessary programs being cut. Finally, AE asserts that any increase in the EES charge due to VoS may be offset by a decrease in the PSA.

The IHE concludes that it is appropriate to recover the societal benefit value through the EES portion of the CBC. Funding this portion of the VoS through the EES, rather than the PSA, more appropriately matches the benefit with the cost (as societal benefits are not avoided purchase power costs) and is a more transparent means of calculating the goal being accomplished.

F. Policy Driven Incentives

1. Background

The third pillar relates to policy driven incentives. According to AE, this proposed adder will be administered in the format commonly known as a performance-based incentive (PBI). In contrast to the other two pillars, the PBI will not fluctuate in order to provide stability to customers who invest in solar generation systems. Like the societal benefits and current incentives, the policy driven incentives will be recovered through the CBC. The PBI will have two offerings. First, the residential offering will include a 20-year PBI to align with common residential solar loan terms. This will help to enable cash-flow neutral scenarios where the customer's bill savings are roughly equal to their loan payments. Second, commercial PBIs will feature a higher PBI value over a shorter time period, increasing the internal rate of return to drive commercial solar adoption. This is similar to the PBI incentive currently offered.[765]

AE states that once the new approach is in place, customers who adopt solar will be locked into the prevailing PBI based on their customer class. In contrast with the other pillars of the VoS that are subject to change, the PBI will not fluctuate. AE expects that this will offer stability for customers with behind-the-meter solar generation systems. At the end of the PBI term, VoS customers will continue to receive the Avoided Costs and Societal Benefit values.[766]

AE offered examples of factors that impact the rate and incentive changes for this pillar, including the availability and rate of federal tax credits, payback period, adjusted value of the other two VoS components, capacity remaining to achieve goals, and time remaining to achieve goals.

[764] AE states that upon approval of the VoS rate proposals, it will request a budget amendment to increase the EES budget by the amount needed to recover the societal benefits portion of the VoS.
[765] AE Ex. 1 at 146-147.
[766] AE Ex. 1 at 147.

AE further explains the PBI will no longer be offered to new solar adopters once the policy goals are achieved or incentives are no longer required to meet policy objectives.[767]

Per AE, the Austin Energy Resource, Generation and Climate Protection Plan to 2030 directs AE to achieve a total of 375 MW of local solar capacity by the end of 2030, of which 200 MW is to be customer sited.[768] SCPC/SUN alleges that AE's proposed changes to the VoS disregards the utility's obligations under the 2030 Climate Plan.[769] AE refutes this argument, and instead argues that the 2030 Climate Plan is what the policy-driven incentives are intended to address.[770] AE states it is currently over halfway to its 2030 target of a 200 MW customer-sited goal. AE asserts that because incentives for solar energy are an effective way to encourage adoption and drive local solar market development and clean energy jobs, it proposes, as part of the next VoS adjustment to be implemented in FY 2024, to collaborate with the community to identify an equitable approach to retire the current Residential Solar Education Program and the Commercial PBI programs and replace them with an incentive adder as the third pillar of the VoS. Moreover, AE commits to exploring a Solar Standard Offer that could add capacity to the Community Solar Program through its community engagement process.[771]

2. Additional PBI Benefits

According to AE, PBIs are advantageous because they encourage customers to maintain the production of their systems, can be calibrated to meet customer needs, can be easily administered and adjusted to achieve strategic goals, and are paid based on monthly production for a period of years. AE says it would continue to promote solar education and provide resources to customers to help them make informed decisions when deciding to install solar. AE states that transitioning to this incentive format will greatly reduce staff time currently required to process incentives and manage participating contractors, allowing staff to refocus efforts to reduce soft costs (such as reducing timelines, reducing permitting and inspection costs, and improving operational efficiency), creating better residential loan offerings, improving customer service, increasing solar penetration in limited income communities, providing community outreach,

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[767] AE Ex. 1 at 147.
[768] Available at: https://austinenergy.com/wcm/connect/6dd1c1c7-77e4-43e4-8789-838eb9f0790d/gen-res-climate-prot-plan-2030.pdf?MOD=AJPERES&CVID=n85G1po.
[769] SCPC/SUN Brief at 23.
[770] AE Ex. 1 at 146.
[771] AE Ex. 1 at 146.

promoting consumer education, developing scholastic education, supporting community resiliency efforts, and expanding community solar.[772]

3. Recovery Method

AE declares the policy driven incentives pillar of the VoS will be recovered by AE through the CBC. AE states the value will be reassessed annually, and that it will go into effect for all new customers with behind-the-meter solar generation systems the following year, as approved by City Council.[773]

G. Impacts to Customers

SCPC/SUN contends that "as a result of its changes to the Value of Solar tariff and other rate design changes, the average distributed solar customer's energy bill will *double*."[774] But even this argument acknowledges that "other rate design changes" contribute to that increase, just as they do for other customers. And SCPC/SUN's argument does not acknowledge that AE's approach actually increases the VoS benefit to distributed solar customers.

AE's proposed methodology results in increases to the VoS rate for all customer classes relative to the current VoS rate. According to AE: (1) for residential and commercial non-demand customers, the proposed VoS rate increases from $0.0970/kWh in 2022 to $0.0991/kWh in 2023; (2) for commercial demand solar capacity customers under 1,000 kW-ac the proposed VoS rate increases from $0.0670/kWh in 2022 to $0.0991/kWh in 2023; and (3) for commercial demand solar capacity customers greater than or equal to 1,000 kW-ac, the proposed VoS rate increases from $0.0470/kWh in 2022 to $0.0724/kWh in 2023. AE illustrates that commercial customers with behind-the-meter solar generation systems under 1,000 kW-ac would realize the largest gains, increasing by $0.0321/kWh.[775] AE considers this to be a significant increase, with a net positive impact to customers, and commits to reevaluating future incentive offerings for alignment with policy goals.

H. Impacts to Utility

AE explains that the avoided cost portion of the VoS, recovered through the PSA, represents the price at which AE is cost neutral as to whether it credits the customer for power produced at the point of load, or delivers an equal unit of power from an offsite generation source.

[772] AE Ex. 1 at 147-148.
[773] AE Ex. 1 at 148.
[774] SCPC/SUN Brief at 23 (emphasis in original).
[775] AE Ex. 1 at 148.

AE asserts that the societal benefits and policy-driven incentives pillars do not contribute to avoided costs to the utility, so these will be recovered through the EES of the CBC. The chart in Figure 9-2 of AE Exhibit 1 represents the incremental annual impacts to the CBC.[776] AE clarifies that this does not necessarily reflect cost increases, as some values that were previously recovered from the PSA will be shifted to the CBC, reducing the PSA and increasing the CBC. AE states the modeled annual CBC budget requirements, referenced in Figure 9-2, assumes many external factors that would go into calculating future societal benefits stay the same. Finally, AE asserts, once policy-driven incentives are added to the VoS, these incentives will impact the CBC budget requirement, but will also replace other solar incentive costs currently recovered through the CBC.[777]

I. Other Programmatic Recommendations

SSC made several suggestions for programmatic changes to VoS, including: (1) expanding the VoS tariff to include solar plus storage; (2) expanding the VoS tariff to allow for additional realizations for microgrids and multifamily developments; (3) setting guardrails to ensure the VoS does not drop below a certain floor over time; (4) revamped rebates program to reach more people; (5) increased solar leasing options; (6) standard solar offer program for community solar/storage; (7) include in the policy-driven incentives pillar an assessment of the program needs that allow efficient processing of solar installation permits; (8) updating the AE billing system; and (9) offering a 24x7 carbon free rate.[778]

AE responds to these suggestions by pointing out that SSC's proposals are outside of the scope of this Base Rate Review.[779] AE contends, as noted in the Procedural Guidelines, only the VoS rates, methodology, and inputs—not programmatic changes—are subject to review through this Base Rate Review.[780] AE also notes that billing system updates will be considered by AE at the appropriate time, which again, is not during this Base Rate Review. Finally, AE asserts that the proposed 24x7 carbon free rate is also beyond the scope of this proceeding.[781]

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[776] AE Ex. 1 at 150.
[777] AE Ex. 1 at 149.
[778] SSC Brief at 1-7.
[779] AE Ex. 2 at 12. At the appropriate time, AE commits to including SSC as stakeholders in the development of programs raised in its brief.
[780] AE Ex. 1 at App. 4.
[781] AE Ex. 1 at App. 4.

SSC counters that several of its proposals ask for the expansion of the VoS tariff to include additional rates, which is within the scope of "rates, methodology, and inputs," but that AE characterized these as programmatic changes.[782] SSC also contends that AE's rate package includes a proposed change to the funding source for VoS, which it contends is like SSC's proposed changes.[783]

The IHE finds that SSC's programmatic recommendations involve issues beyond the scope of this Base Rate Review, although the IHE acknowledges that "rates, methodology, and inputs" lack clarity. Accordingly, the IHE recommends that AE more clearly define the scope of the items that will be considered before the next reassessment of the VoS.

Ultimately, the IHE finds AE's proposed VoS approach and tariff to be reasonable and appropriate and recommends approval.

VII. PRI-2 High Load Factor Tariff

AE proposes a new High Load Factor Primary Voltage tariff for customers who take service at primary voltage at a load level greater than or equal to 3 MW but less than 20 MW, and whose monthly average load factor during the course of the year meets or exceeds 85%.[784] Data Foundry requested the creation of this tariff, which TIEC also supports. This new system of charges would create a new rate class of AE customers, the PRI-2 High Load Factor (PRI-2 HLF) class.[785] AE characterizes the creation of the new rate class as revenue neutral with regard to base rates.[786] AE notes that it currently offers a high-load factor rate option to primary customers at a load size above 20 MW,[787] and that the new class would make the same rate option available to primary customers at lower load levels but with similar steady load profiles. According to AE, the PRI-2 HLF Tariff advances the important ratemaking objectives of fairness, economic efficiency, and revenue stability.[788] AE proposes that the PRI-2 HLF class be exempted from energy efficiency programs and energy efficiency charges, like the existing PRI-4 HLF class.

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[782] SSC Brief at 7.
[783] SSC Brief at 7.
[784] AE Ex. 1b.
[785] AE Ex. 1b at 2.
[786] AE Ex. 1b at 2.
[787] AE Ex. 1b at 3.
[788] AE Ex. 1b at 2.

No participants specifically oppose the creation of the PRI-2 HLF rate class, nor are most of the details of the new rate class contested (as discussed in AE's Amendment to the 2022 Base Rate Filing Package).[789]

Mr. Robbins criticizes the PRI-2 HLF rate class because it lacks an energy charge. The IHE agrees with AE that this criticism appears to arise from misconceptions concerning the rate design for the class and should not serve as a basis for rejecting the new rate class or redesigning its rate structure.[790]

In addition, SCPC/SUN and Mr. Robbins oppose the proposed exemption of the new class from energy efficiency charges, with AE, TIEC, and Data Foundry offering contrary arguments. As discussed below, the IHE finds that AE, TIEC, and Data Foundry's argument should be accepted, and that the new rate class should be exempted from the EES.

The IHE recommends that the proposed tariff be adopted, creating the PRI-2 HLF rate class.

VIII. Other Issues

A. Proposed Power Supply Adjustment Factor Adjustment for Primary Substation Customers

TIEC recommends that the proposed PSA should be revised to include a separate Primary Substation Adjustment Factor.[791] AE opposes this recommendation. AE first points out that the PSA is not under review in this proceeding. AE notes that it has differentiated the PSA charges by voltage—specifically, the service provided at transmission, primary, and secondary voltages—to recognize the differences in energy losses. AE also notes that it does not have any primary substation customers. AE argues that primary distribution customers are within the primary distribution class and should be allocated a proportional share of the costs for the primary distribution system as developed by AE and included in the proposed base rate charge.

Although the PSA is not under review in this proceeding, the IHE has recommended that AE, TIEC, and NXP work to develop a Primary Substation rate for distribution service where the ratepayer is the only recipient of service on that line. As a result, to the extent necessary, the IHE recommends that AE revisit the PSA to ensure that it is consistent with this recommendation.

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789 AE Ex. 1b at 4.
790 AE Ex. 9 at 60-61.
791 TIEC Brief at 40.

B. Energy Efficiency Service

AE proposes a new PRI-2 HLF rate class available to qualifying customers. AE currently offers a high-load factor rate option to primary customers at a load size above 20 MW, and AE's proposal makes the same rate option available to primary customers at lower load levels but with similar load profiles.[792] AE notes that this rate option is being extended to customers who exhibit steady loads and therefore utilize system resources more efficiently.[793] The PRI-2 HLF class would be exempted from energy efficiency programs and energy efficiency charges.

EES Exemption

SCPC/SUN and Paul Robbins object to this exemption. SCPC/SUN opposes the exemption of the PRI-2 HLF class from energy efficiency charges and argues that all customers should be required to pay an EES charge. SCPC/SUN also argues that any and all customers can make private efficiency investments.[794]

AE notes that the exemption of the PRI-2 HLF class from energy efficiency charges is consistent with the treatment of AE's PRI-4 HLF rate class by recognizing that larger customers generally have sophisticated energy management programs, often have corporate mandates to manage energy use, and are capable of implementing their own energy efficiency measures.[795] As a result, AE notes that these customers are not eligible to participate in AE's energy efficiency programs, and it is logical that they would not be subject to charges associated with programs they have no opportunity to benefit from. Consistent with this approach, TIEC and Data Foundry have explained that they do not benefit from AE's energy efficiency programs.[796] As stated in their briefs, TIEC and Data Foundry note that the Texas Legislature codified the exemption of industrial customers from utility-administered energy efficiency programs in areas with retail competition in 2007.[797] The PUC then conducted rulemakings instructing that industrial customers cannot be required to participate in a Commission-jurisdictional energy efficiency program.[798]

The IHE agrees with AE, TIEC, and Data Foundry. The same policy should hold true for AE and its customers, and AE's recommendation should be adopted.

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[792] AE Ex. 1b at 3.
[793] AE Ex. 1b at 2.
[794] SCPC/SUN Brief at 29-30.
[795] AE Ex. 1b at 3-4.
[796] TIEC Brief at 42; Data Foundry Brief at 6.
[797] Data Foundry Brief at 8, *citing* Data Foundry Ex. 1 and TIEC Ex. 2 at 13-14.
[798] Data Foundry Brief at 8, *citing Rulemaking Proceeding to Amend Energy Efficiency Rules*, Project No. 39674.

Mandatory Energy Efficiency Reporting for High Load Factor Customers

SCPC/SUN also takes issue with the lack of quantifiable energy efficiency benefits that high load factor customers provide to the system, and recommends that all customers under the PRI-2 HLF rate class, and other transmission-level and primary-level customers, be subject to an "EES opt-out provision" in exchange for "an annual public report on their efforts to reduce energy use, lower peak demand and take actions to generate power locally."[799] AE has not proposed such a mandatory reporting requirement, and generally agrees with TIEC and Data Foundry that requiring these customers to publicly disclose their energy efficiency efforts and investments threatens the proprietary and confidential nature of such information, and would provide no benefit to AE's energy efficiency programs.[800]

Again, the IHE agrees with AE, TIEC, and Data Foundry on this issue. High load factor customers should not be required to report on their energy efficiency measures, which they have clearly stated are proprietary and confidential.

Subsidization

Paul Robbins also disputes AE's proposal to exempt the PRI-2 HLF class from energy efficiency charges and states that it will lead to subsidization.[801] AE disagrees and points out that if PRI-2 HLF customers were assessed the energy efficiency component of the CBC, that would cause costs to be shifted from the customers who participate in the programs onto PRI-2 HLF customers. The IHE agrees with AE that Mr. Robbins' proposal appears to create subsidization.

Energy Rates

Mr. Robbins raises several other concerns about the PRI-2 HLF class. First, he claims that PRI-2 HLF customers would not see energy rates.[802] AE argues that it is appropriate that PRI-2 HLF customers will see no energy base rates. AE points out that there are no energy costs to be recovered under an energy base rate, and the use of an energy rate to recover demand and customer costs creates fairness and efficiency problems.[803] Instead, AE explains that PRI-2 HLF customers would be charged the energy rate under the PSA.[804] The PSA represents the cost of energy, and will be assessed to PRI-2 HLF customers on a per-kWh basis, the same as all other customers. The

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799 SCPC/SUN Brief at 34-35.
800 TIEC Brief at 43-44; Data Foundry Brief at 9-14.
801 P. Robbins Ex. 1 at Section 2.2.
802 P. Robbins Ex. 1 at Section 2.2.
803 AE Ex. 9 at 60.
804 AE Ex. 9 at 60.

IHE agrees with AE that the PSA is the mechanism through which energy costs are recovered and recommends rejection of Mr. Robbins' proposal.

High Load Factor Customer Considerations

Mr. Robbins also argues that the lack of an energy charge for PRI-2 HLF customers would induce waste.[805] AE responds that energy consumption by commercial customers is not the same as consumption by residential customers.[806] AE notes that the conservation considerations are different for commercial customers as compared to residential; for a commercial or industrial customer, energy consumption fuels the production of goods and services and the creation of economic value.[807] AE contends that, because much of AE's energy supply comes from renewable resources, all customers who pay the PSA, including PRI-2 HLF customers, contribute to clean energy.[808] The IHE agrees with AE's characterization of high load factor customer traits and the securing of clean energy for sale by AE.

Mr. Robbins also contends that the creation of a PRI-2 HLF class will reinforce an undesirable pattern.[809] AE responds that, providing the high-load factor option to customers with load above 20 MW, but not for customers with load between 3 MW and 20 MW is inconsistent and could be perceived as discriminatory. The IHE agrees with AE's claim that the proposal avoids the issue of discrimination by extending the same option to primary customers at lower load levels, mitigating discrimination in the rate structure.

The IHE agrees with AE that its proposal to create a new PRI-2 HLF rate class extends a high-load factor rate option that is currently available to AE's largest commercial customers to primary customers at lower load levels but with similar load profiles. Both types of customers exhibit steady loads and use system resources efficiently. The IHE recommends that AE's new PRI-2 HLF rate class proposal be adopted.

C. Challenges to CAP Program Benefits

AE argues that its proposed base rate design will significantly increase benefits under the CAP program to achieve greater levels of social equity among AE's residential customers. Assuming AE's customer charge is approved, AE argues that the value of the CAP program's

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805 AE Ex. 9 at 60.
806 AE Ex. 9 at 60.
807 AE Ex. 9 at 60.
808 AE Ex. 9 at 60-61.
809 AE Ex. 9 at 60-61.

waiver of the customer charge increases by 150%, from $10 per month to $25 per month.[810] Using load information from the COS Study, AE expects the total value of CAP benefits to increase from $8.3 million to $14.4 million.[811] AE notes that the increases in this value do not affect the base rates of any customer, but rather the increases are funded exclusively through the CBC, which is not under review in this proceeding.[812]

Mr. Robbins argues that AE is increasing the CAP subsidy to compensate for radical rate restructuring.[813] Specifically, Mr. Robbins argues that AE is proposing a $6.1 million increase in the overall program discount given to CAP customers, which will increase pass-through costs of the CBC.[814] Adjusting for 2021 residential consumption rates and the inside-city customer CAP charge, Mr. Robbins argues that the requested increase will result in an actual increase of $11.15 per year per customer on top of the rate increase already proposed for AE's non-CAP customers.[815]

In response, AE argues that it has not proposed changes to the structure of the CAP.[816] Instead, AE submits any expected increase in benefits under the CAP program is a byproduct of the changes to the residential base rate design.[817] AE submits that the proposed base rate restructuring is therefore responsible for the increase in the total value of CAP benefits.[818]

The IHE agrees with AE that the proposed rates have no effect on CAP structure, but instead would yield an increase in the amount of CAP benefits provided to those enrolled in the program. As noted by AE, CAP benefits are funded through the CBC, which is not subject to review in this proceeding.

Mr. Robbins also argues that AE has experienced chronic and long-standing problems with its discount program for the poor since it was implemented in 2013.[819] Mr. Robbins contends that some ratepayer revenue is being misspent by awarding discounts to the wrong customers through, what he calls, "AE's profoundly flawed automatic enrollment program."[820] Mr. Robbins submits

[810] AE Brief at 73.
[811] AE Ex. 9 at 36.
[812] AE Brief at 73.
[813] P. Robbins Brief at 4.
[814] P. Robbins Brief at 4.
[815] P. Robbins Brief at 4.
[816] AE Brief at 73.
[817] AE Ex. 9 at 47.
[818] AE Brief at 73.
[819] P. Robbins Brief at 10.
[820] P. Robbins Brief at 10.

that this has repeatedly led to embarrassing revelations of AE customers with documented high-property wealth being on the CAP roles.

SSC shares Mr. Robbins' concerns with CAP enrollment procedures. SSC argues there may be customers that qualify for CAP, but have yet to enroll in the program due to access issues.[821] SSC proposes that AE consider expanded access to these customers. Specifically, SSC proposes a program that identifies census tracts with a percentage of CAP customers above a certain threshold, and then enroll all customers in that tract in CAP. SSC submits that this approach would help remove barriers that some customers may have in accessing the CAP program.

In response, AE argues that Mr. Robbins and SSC's proposed programmatic changes to the CAP, including changes to the enrollment process, are outside the scope of this Base Rate Review.[822] The IHE agrees with AE. CAP enrollment procedures and related efforts to ensure only those that qualify are enrolled in CAP are outside the purview of this proceeding.

IX. Conclusion

The IHE commends AE and the participants for their participation and for offering well-reasoned arguments for their positions and interests. The IHE's goal and duty in this Final Recommendation is to provide City Council with a basis for adopting AE's or participants' proposals as explained above. The IHE recommends approval of a substantial portion of AE's requested revenue requirement, cost allocation methods, and VoS. The IHE, however, recommends that AE's proposed base rate design and targeted customer assistance programs like CAP be revisited by AE and the participants. To the extent the IHE submits certain policy choices to City Council, those considerations are set forth in this Final Recommendation.

Travis Vickery
Impartial Hearing Examiner
Date: September 9, 2022

[821] SSC Brief at 2.
[822] AE Brief at 73.

Glossary

2WR – Holly Cooper and Vicki Dennis (2WR)
Administrative and General expenses (A&G)
American Public Power Association (APPA)
Ancillary Service (AS)
Austin Energy (AE)
Austin Energy Node (AEN)
Average & Excess 4CP allocation methodology (A&E 4CP or 4CP)
Baseload-Intermediate-Peak methodology (BIP)
Brownsville Public Utilities Board (BPUB)
City of Austin (City)
City of Austin Financial Services Division (FSD)
Coalition for Clean, Affordable and Reliable Energy (CCARE)
Coincident Peak (CP)
Commercial and Industrial (C&I)
Community Benefit Charge (CBC)
Consumer Energy Solutions budget (CES)
Contributions in Aid of Construction (CIAC)
Cost of Service (COS)
Cost of Service Study (COS Study)
Customer Assistance Program (CAP)
Debt Service Coverage Ratio (DSCR)
Energy Efficiency Services costs (EES)
Electric Reliability Council of Texas (ERCOT)
ERCOT Four Coincident Peak methodology (4CP)
ERCOT 12 Coincident Peak methodology (12CP)
Electric Utility Commission (EUC)
Fayette Power Plant [coal] (FPP)
Fiscal Year (FY)
Fitch Credit Ratings (Fitch)
General Fund Transfer (GFT)
Homeowners United for Rate Fairness (HURF)
Independent Consumer Advocate (ICA)
Independent Hearing Examiner (IHE)
Internally Generated Funds for Construction (IGFFC)
Lower Colorado River Authority (LCRA)
Lubbock Power and Light (LP&L)
Mega-watt (MW)
Nacogdoches Power Plant (Nacogdoches)
National Association of Regulatory Utility Commissioners (NARUC)
NARUC Cost Allocation Manual (CAM)
National Rural Electric Cooperative Association (NRECA)
Non-Coincident Peak (NCP)
Non-spinning Reserve Service (NSRS)
NXP Semiconductors, Inc. (NXP)

Operation and Maintenance (O&M)
Performance-Based Incentive (PBI)
Photovoltaic (PV)
Point of Interconnection (POI)
Power Supply Adjustment (PSA)
PRI-2 High Load Factor (PRI-2 HLF)
Proposal for Decision (PFD)
Public Utility Commission of Texas (PUC or Commission)
Public Utility Regulatory Act (PURA)
Regulation Service – Down (REG DOWN)
Regulation Service – Up (REG UP)
Responsive Reserve Service (RRS)
Resource Management Commission (RMC)
Retail Electric Provider (REP)
Sierra Club, Public Citizen, and Solar United Neighbors (SCPC/SUN)
Social Cost of Carbon (SC-CO2)
South Texas Project [nuclear] (STP)
Sum of Maximum Demand (SMD)
Texas Industrial Energy Consumers (TIEC)
The Town Lake Center (TLC)
Transmission Cost of Service (TCOS)
TCOS Rate Filing Package for Non-Investor Owned Utilities (TCOS Non-IOU RFP)
Value of Solar (VoS)