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AUSTIN ENERGY 2022 BASE RATE REVIEW	§ §	**BEFORE THE CITY OF AUSTIN IMPARTIAL HEARING EXAMINER**
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NXP SEMICONDUCTORS' CROSS REBUTTAL POSITION STATEMENT

NXP Semiconductors ("NXP"), by and through its attorneys of record, files this Cross Rebuttal Position Statement in accordance with Section E.3(a) of the 2022 Austin Energy Base Rate Review Procedural Guidelines. NXP takes the positions set out in the cross rebuttal testimony of James W. Daniel, which is being filed on July 1, 2022, and is incorporated by reference. NXP reserves the right to take additional positions based on the evidence and positions of other participants and to participate in the Final Conference in this proceeding.

Respectfully submitted,

By: */s/ J. Christopher Hughes*________________________

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of this document was served on all parties of record in this proceeding, in accordance with Austin Energy Instructions, on the 1st day of July, 2022.

*/s/ J. Christopher Hughes*______________
J. Christopher Hughes

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AUSTIN ENERGY 2022 BASE RATE REVIEW	§	**BEFORE THE CITY OF AUSTIN**
	§	**IMPARTIAL HEARING EXAMINER**
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CROSS-REBUTTAL POSITION STATEMENT AND EXHIBITS

OF

JAMES W. DANIEL

ON BEHALF OF

NXP USA, INC.

JULY 1, 2022

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EXHIBITS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James W. Daniel. My business address is 919 Congress Avenue, Suite 1110, Austin, Texas 78701.

Q. ARE YOU THE SAME JAMES W. DANIEL THAT PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF NXP USA, INC. ("NXP")?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR CROSS-REBUTTAL POSITION STATEMENT?

A. The purpose of my Cross-Rebuttal Position Statement is to rebut portions of the Initial Presentation of the Independent Consumer Advocate's ("ICA") witness Clarence Johnson. Due to the limited time afforded by the Austin Energy procedural schedule, this Cross-Rebuttal is limited to the areas or issues that have the largest impact on AE's COSS and class revenue distribution.

Q. PLEASE SUMMARIZE THE ISSUES YOU IDENTIFY WITH ICA'S COST ALLOCATION PROPOSALS.

A. My Cross-Rebuttal Position Statement addresses problems with the following adjustments to AE's COSS and revenue distribution proposed by the ICA through Mr. Johnson's testimony:

(1) The ICA improperly recommends the use of the base-intermediate-peak ("BIP") cost allocation methodology for allocating AE's production demand-related costs.

(2) The ICA incorrectly allocates a portion of the costs of smart meters to all customer classes based on a class revenue requirement allocation factor. This allocation is based on the erroneous assumption that smart meters provide benefits to all customers.

(3) The ICA incorrectly allocates a portion of customer service expenses based on a customer class revenue requirement allocation factor.

(4) The ICA incorrectly functionalizes too much executive salaries in Account 920 to the production function.

(5) The ICA's proposed methodology for distributing the proposed AE revenue increase to the customer classes is flawed and should not be approved.

II. ICA's ALLOCATION OF PRODUCTION DEMAND-RELATED COSTS

Q. PLEASE DESCRIBE THE ICA'S PROPOSED METHODOLOGY FOR ALLOCATING AE'S PRODUCTION DEMAND-RELATED COSTS.

A. Mr. Johnson is proposing the use of a BIP allocation methodology for allocating AE's production demand-related costs.

Q. PLEASE PROVIDE A BRIEF DESCRIPTION OF THE BIP COST ALLOCATION METHODOLOGY.

A. The BIP methodology for allocating production demand-related costs first assigns the costs of each generating plant to either (1) the base load period, (2) the intermediate or shoulder period, or (3) the peak demand period of the utility. Plants with the lowest operating costs are assigned to the base period, while plants with the highest operating costs are assigned to the peak period. Plants with more average operating costs are assigned to the intermediate or shoulder peak periods. The costs assigned to each category or time period are then allocated to the customer classes using different cost allocation methodologies.

Q. WHAT IS THE RESULT OF MR. JOHNSON'S ASSIGNMENT OF AE'S GENERATING PLANT COSTS TO THE THREE BIP PERIODS?

A. As shown on page 27 of Mr. Johnson's Initial Presentation, using his recommended BIP-P methodology results in the following production demand costs assignment:

Table R1

BIP Cost Assignment

Period	Percent
Base	79.8%
Intermediate	9.4%
Peak	10.8%
Total	100.0%

Q. HOW DOES MR. JOHNSON ALLOCATE EACH BIP PERIOD'S COSTS TO THE CUSTOMER CLASSES?

A. As discussed on page 26 of Mr. Johnson's Initial Presentation, he allocates (1) all of the base period costs on average demands, or energy, (2) 39% of the intermediate period cost on energy and 61% using 12CP demands, and (3) the peak period costs on the ERCOT 4CP demands.[1] Under ICA's proposal, this results in 83.5% (79.8% plus 39% times 9.4%) of AE's fixed production demand-related costs being allocated using an energy allocation factor.

[1] The ERCOT 4CP demand methodology is how AE, the Public Utility Commission ("PUC"), and ERCOT allocate transmission costs.

Q. DOES THIS ICA PROPOSAL ACHIEVE ITS OBJECTIVE?

A. Yes. The question on page 23 of Mr. Johnson's Initial Presentation states:

> Q. IS IT YOUR POSITION THAT THE APPROPRIATE PRODUCTION DEMAND ALLOCATION METHOD IN THIS CASE SHOULD EFFECTIVELY REFLECT CUSTOMER CLASS ANNUAL AVERAGE ENERGY USE?

The ICA's answer to the question is "yes."

Q. WHAT IS YOUR VIEW OF THE ICA'S PROPOSED USE OF THE BIP METHODOLOGY FOR ALLOCATING AE'S PRODUCTION DEMAND-RELATED COSTS?

A. The BIP methodology should not be used to allocate AE's production demand-related costs. One of Mr. Johnson's objections to AE's proposed ERCOT 12CP demand allocation methodology for allocating production demand-related costs is that the methodology does not recognize average demand, or energy usage. However, the ICA's BIP methodology goes to the other extreme of allocating 83.5% of AE's fixed production demand-related costs using an energy only allocation factor.

Q. HAVE OTHER JURISDICTIONS OR RATEMAKING BODIES UTILIZED THE BIP METHODOLOGY FOR PRODUCTION COST ALLOCATION?

A. I am not aware of the BIP methodology ever being approved for an electric utility in Texas.[2] Additionally, in his response to RFIs from TIEC and NXP, Mr. Johnson also indicates that he has no knowledge of the BIP methodology being approved for use by any electric utility in Texas, municipally-owned or otherwise, but does acknowledge that he proposed the BIP

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[2] This includes municipally-owned utilities ("MOUs"), investor-owned utilities ("IOUs") and cooperatives.

methodology in the 2016 Austin Energy Rate Review. The BIP methodology was not adopted in that rate review. Below I will discuss some of the problems with the BIP methodology.

Q. DOES THE BIP METHODOLOGY ALLOCATE MORE PRODUCTION DEMAND-RELATED COSTS TO HIGH LOAD FACTOR ("HLF") CUSTOMER CLASSES THAN OTHER COMMONLY USED METHODOLOGIES?

A. Yes. The BIP methodology results in a tremendous shift in cost responsibility from less efficient low load factor ("LLF") customers to more efficient high load factor ("HLF") customers as compared to more conventional recognized allocation methodologies. This cost shift is shown on the table below.

Table R2

Rate Class	12CP-ERCOT Peak	BIP (Note 1)	Impact - $	Impact - %
Residential	$ 374,653,342	$ 360,952,336	$ (13,701,006)	-3.7%
Secondary Voltage < 10 kW	23,740,654	23,755,916	15,262	0.1%
Secondary Voltage ≥ 10 < 300 kW	118,368,061	117,536,272	(831,789)	-0.7%
Secondary Voltage ≥ 300 kW	86,588,435	89,994,357	3,405,921	3.9%
Primary Voltage < 3 MW	9,889,409	10,729,776	840,367	8.5%
Primary Voltage ≥ 3 < 20 MW	26,040,268	29,846,788	3,806,520	14.6%
Primary Voltage ≥ 20 MW @ 85% aLF	38,838,726	43,797,883	4,959,157	12.8%
Transmission	913,278	938,455	25,177	2.8%
Transmission Voltage ≥ 20 MW @ 85% aLF	3,519,886	4,269,366	749,480	21.3%
Service Area Street Lighting	-	-	-	0.0%
City-Owned Private Outdoor Lighting	3,758,677	3,903,674	144,998	3.9%
Customer-Owned Non-Metered Lighting	56,297	79,652	23,355	41.5%
Customer-Owned Metered Lighting	476,458	497,062	20,604	4.3%
Total	**$ 686,843,493**	**$ 686,301,537**	**$ (541,956)**	**-0.1%**

Note 1: The difference in base revenues is due to additional costs being assigned to the SL class under the BIP methodology. These revenues are collected through the Community Service rider and are not included in Base Rates.

As shown, the impact of the BIP methodology is dramatic and would cause severe impacts on some customer classes as compared to Austin Energy's proposed allocation, and to NXP's proposal.

Q. DOES THE ICA CLAIM THAT AE HAS PREVIOUSLY SUPPORTED THE BIP PRODUCTION DEMAND-RELATED COST ALLOCATION METHOD?

A. Yes. On page 29 of his Initial Presentation, Mr. Johnson states that in AE's 2011 rate case AE's cost of service consultant, R.W. Beck and Associates,[3] "recommended BIP during the public involvement process" of that case.

Q. DO YOU AGREE WITH THAT CLAIM?

A. I was not present when the claimed statement by the R.W. Beck and Associates consultant was made. However, based on information I have reviewed related to that 2011 AE rate case, I have seen evidence that contradicts this claim. The City Council's decision in AE's 2011 rate case was appealed to the PUC. In that PUC case, Docket No. 40627, an AE witness, Joseph Mancinelli, from the same consultant, R.W. Beck and Associates, filed testimony in support of the A&E w/4CP cost allocation methodology (the same methodology that I have recommended the City utilize as reflected in NXP's Position Statement). In Mr. Mancinelli's direct testimony, he states that the BIP method was considered along with other allocation methodologies but that the City Council adopted the A&E w/4CP methodology.

[3] It should be noted that NewGen Strategies, the primary rate consultant to AE for the 2022 rate study was started by a group of former R.W. Beck employees. Some of the former R.W. Beck employees/current NewGen Strategies employees have worked on the 2011, 2016 and 2022 AE Rate Studies.

In Mr. Mancinelli's rebuttal testimony addressing the Office of Public Utility Counsel's ("OPUC") testimony, he provides more detailed support for the A&E w/4CP methodology and also explains why OPUC's proposed BIP allocation methodology should be rejected. An excerpt from this AE rebuttal testimony is provided as my Exhibit NXP-JWD-R1. I would add that I am in agreement with this AE rebuttal testimony in Docket No. 40627 regarding problems with the BIP methodology.

Q. IN PUC DOCKET NO. 40627, DID THE PUC STAFF SUPPORT OPUC'S PROPSOAL TO USE THE BIP METHODOLOGY FOR ALLOCATING AE'S PRODUCTION DEMAND COSTS?

A. No. In that AE case, the PUC Staff recommended the A&E w/4CP methodology.

Q. AT THE TIME OF AE's 2011 RATE REVIEW AND DOCKET NO. 40627 HAD THE ERCOT NODAL MARKET BEEN IMPLEMENTED?

A. Yes. Mr. Johnson indicates that the change to a nodal market in ERCOT is a reason for changing how AE's production demand-related costs should be allocated.[4] As determined by the City Council for the 2011 rate review and by AE and PUC Staff witnesses in Docket No. 40627, apparently implementation of the ERCOT Nodal Market was not a cause for changing from an A&E w/4CP allocation factor in favor of a BIP methodology.

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[4] Initial Presentation of ICA witness Clarence Johnson page 19, line 18, to page 20, line 2, in favor of a BIP methodology.

Q. IN AE's 2016 RATE CASE, DID MR. MANCINELLI FILE REBUTTAL TESTIMONY THAT ALSO REFUTES MR. JOHNSON'S CLAIM THAT AN AE CONSULTANT RECOMMENDED THE BIP METHODOLOGY?

A. Yes. On page 38 of his 2016 rebuttal testimony, Mr. Mancinelli provides the following discussion:

> Q. DURING THE 2012 RATE REVIEW, DID THE RATES CONSULTANT RECOMMEND THE BIP ALLOCATION METHOD OVER OTHER ALLOCATION METHODS?
>
> A. No. BIP was never recommended over other allocation methods. The BIP method was simply discussed and recommended to the rate review Public Involvement Committee ("PIC") as the *alternative* to the POD method. The PIC evaluated three allocation methods representing differing perspectives. The PIC reviewed the CP, A&E, and BIP allocation methods.
>
> Q. HOW CAN YOU BE SURE OF THIS ASSERTION?
>
> A. I was the rate consultant that worked with AE throughout the PIC process.

In his 2016 rebuttal testimony, Mr. Mancinelli also provides criticism of Mr. Johnson's BIP proposal in the 2016 AE rate case.

Q. DOES MR. JOHNSON ALSO CLAIM AE IS UNIQUE IN THE ERCOT MARKET SINCE IT IS A BUNDLED UTILITY UNLIKE THE IOUs IN ERCOT?

A. Yes. On page 19, line 1, through page 20, line 2, of his Initial Presentation, Mr. Johnson discusses this claim and also claims that bundled electric utilities like AE have more complex production cost allocation issues.

Q. DO YOU AGREE?

A. No. CPS Energy is similar to AE. CPS Energy is a bundled MOU in ERCOT that owns significant generation resources and serves a comparable load (with both extensive residential customers and high load factor customers over a large geographic area). Attached as my Exhibit NXP-JWD-R2, is a copy of a CPS Energy presentation to its Rate Advisory Committee ("RAC") on "Allocating Revenue Requirements to Customer Groups," dated September 23, 2021.[5] As shown on page 13 of that presentation, CPS Energy allocates its production non-fuel costs (production demand-related costs) using an average & excess ("A&E") demand allocation methodology.

Q. DO NON-ERCOT INTEGRATED IOU'S IN TEXAS USE THE BIP METHODOLOGY?

A. No. As stated in NXP's Statement of Position, all non-ERCOT IOU's use the A&W/w4CP methodology.

Q. DOES THAT PORTION OF MR. JOHNSON'S INITIAL PRESENTATION ALSO CLAIM THAT AE HAS MORE COMPLEX ALLOCATION ISSUES AS A BUNDLED MOU IN ERCOT?

A. Yes. In addition, on page 22 line 8, through page 23, line 3, of his Initial Presentation, Mr. Johnson discusses how MOUs "such as AE" consider multiple factors such as environmental impact, climate change, capital costs, forecasted system demands, ERCOT market prices, fuel types and energy costs when planning new generation resources.

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5 This CPS Energy presentation was obtained from CPS Energy's website.

Q. DO OTHER ERCOT MOUs CONSIDER SIMILAR MULTIPLE OBJECTIVES?

A. Yes. Attached as my Exhibit NXP-JWD-R3 is a copy of two CPS Energy presentations to its RAC. One presentation is titled "Generation Utilization Update" and dated May 26, 2022, and the other presentation is titled "Modeling, Assumptions & Scenarios" and is dated June 16, 2022.

CPS Energy's June 16th presentation discusses various factors that CPS Energy considers during generation resource planning. This is similar to Mr. Johnson's reference to factors other than peak demand that AE considers for generation resource planning. However, page 8 of the presentation states that forecasted energy sales are used for "revenue planning" while forecasted peak demand is used for "power generation long-term capacity planning".

In addition, CPS Energy's May 26th presentation indicates that only one factor drives its decisions on capacity additions. That factor is the critical objective of meeting its customers' peak demand plus a reserve margin. For example, on page 4 of that presentation, it states that "Our generation planning strategy is to provide sufficient capacity to protect our customers from exposure to high market prices" which typically occur during the summer months.

The bottom line is that CPS Energy's production demand-related costs are caused by its peak demand capacity requirements. This cost causation, as recognized by CPS Energy, supports the need to use the A&E allocation methodology rather than a BIP methodology. The same is true for AE.

Q. IN AE's 2022 BASE RATE FILING PACKAGE DOES AE USE CPS ENERGY FOR COMPARISON PURPOSES?

A. Yes. AE uses CPS Energy in its benchmarking rate analysis and in its affordability, analysis included in the Appendices to AE's Base Rate Filing Package.

Q. IF THE BIP METHODOLOGY IS CHOSEN FOR USE BY AE TO ALLOCATE DEMAND-RELATED PRODUCTION COSTS, DOES IT CREATE A CORRESPONDING MISALIGNMENT OF THE BASE LOAD, INTERMEDIATE, AND PEAKER PRODUCTION HEDGE BENEFITS IN THE AE POWER SUPPLY ADJUSTMENT ("PSA") CLAUSE?

A. Yes, there would be a misalignment of the demand-related production costs allocated based on BIP and the energy-related production hedge benefits reflected in the AE PSA allocated on energy.

Q. PLEASE EXPLAIN.

A. Let's start with the demand-related capacity cost allocation for base load resources with higher capacity cost and lower energy cost. The BIP methodology allocates the higher base load capacity costs on energy across the entire year. This impacts the high load factor customer classes the most and the low load factor customers the least. However, the hedge benefit derived from the base load resources is greatest during the high-priced summer months when peak loads are the highest, because those are the lowest per unit cost resources and will sell into the market when prices are peaking more frequently. Proportional energy use is greatest during the summer months for the low load factor customer classes giving them a larger proportion of the hedge benefit and the high load factor customer classes a smaller proportion than based on an annual energy average. The opposite is true during the off-peak and shoulder months, when the hedge benefit derived from the base load resources is the least. Proportional energy use is greatest during the shoulder and off-peak months for the high load factor customer classes, giving them a larger proportion of the smallest hedge benefit and the low load factor customer classes a smaller proportion of the smallest hedge benefit than based on a higher annual energy average. Bottom line, the high load factor customer classes would be allocated a higher annual energy percentage of the higher cost baseload resources based on the BIP methodology, and receive less than an annual energy percentage of the hedge benefit for the year through the PSA.

Q. WHAT CHANGES WOULD AE HAVE TO MAKE TO ITS PSA TO CORRECT FOR THIS MISALIGNMENT OF THE HEDGE BENEFIT CAUSED BY ALLOCATING DEMAND-RELATED BASE LOAD PRODUCTION COSTS BASED ON THE BIP METHODOLOGY?

A. AE would have to concurrently modify its PSA calculations to allocate the base load hedge benefit between customer classes based on the BIP methodology, which would be on an annual energy allocation rather than on a monthly energy basis.

Q. IS AE'S PSA A PART OF AUSTIN ENERGY'S 2022 BASE RATE REVIEW?

A. AE has clearly designated that the AE PSA is not a part of the Austin Energy 2022 Base Rate Review.

Q. WHAT ABOUT INTERMEDIATE RESOURCES?

A. Their alignment impact is somewhere between the baseload and peaking resources.

Q. WHAT DEMAND-RELATED PRODUCTION COST ALLOCATOR SHOULD AE USE TO MAINTAIN ALIGNMENT BETWEEN BASE RATES AND ITS PSA?

A. The A&E w/4CP allocation factor recognizes the capacity/energy tradeoff in the allocation of fixed capacity costs and it also ensures that all classes are allocated demand-related fixed production costs based on cost causation.

III. ALLOCATION OF METER COSTS

Q. DOES MR. JOHNSON OPPOSE AE'S ALLOCATION OF METER COSTS?

A. Yes. Mr. Johnson discusses his proposed methodology for allocating AE's meter costs on page 42, line 12, through page 45, line 5, of his Initial Presentation. Mr. Johnson opposes AE' use of a traditional weighted meter cost allocation methodology because "AE has been aggressive in the sophistication of the meters it deploys." Since these smart meters can allow for additional functions to be performed, Mr. Johnson recommends allocating 51% of the meter costs based on the customer class revenue requirement.

Q. DO YOU AGREE WITH THE ICA'S PROPOSED METHODOLOGY FOR ALLOCATING METER COSTS?

A. No. The deployment of smart meters for residential customers is not unique to AE. In fact, the deployment of smart meters has occurred at all major utilities in Texas. It is my experience that these other utilities still allocate 100% of meter costs using a weighted meter cost allocation methodology.

Q. HAS MR. JOHNSON SUPPORTED HIS CLAIM THAT SMART METERS PROVIDE SYSTEM BENEFITS?

A. No. Mr. Johnson has not provided any quantification of the claimed system benefits. The only support for his claim is an AE RFI response that also generally describes potential system benefits without any quantification as to the amount of any system benefits.

Q. WILL MR. JOHNSON'S PROPOSED METER ALLOCATION METHODOLOGY ALLOCATE THE COST OF AE'S NEW SMART METERS TO CUSTOMERS THAT ALREADY HAVE SOPHISTICATED METERS?

A. Yes. Larger customers already have sophisticated meters with functions similar to AE's new smart meters. Under the ICA's proposed allocation methodology, larger customers would be required to pay for their sophisticated meters plus an allocated share of the costs of the newly deployed smart meters that they do not utilize.

Q. DO THE PUC'S SUBSTANTIVE RULES PROHIBIT THIS TYPE OF SUBSIDIZATION FOR THE COST OF SMART METERS DEPLOYED BY IOUs?

A. Yes. PUC Substantive Rule §25.130(k) requires the costs of smart meters deployed to a customer class to be surcharged only to the customers in that customer class. AE's meter cost allocation should accomplish this result.

Based on the problems discussed above, Mr. Johnson's meter cost allocation proposal should be rejected.

Q. DOES MR. JOHNSON RELY ON OTHER SOURCES FOR SUPPORT OF HIS PROPOSED METER COST ALLOCATION?

A. Yes. As support for his proposed meter allocation methodology, Mr. Johnson refers to testimony filed in a Baltimore Gas & Electric Company ("BG&E") rate case before the Maryland Public Service Commission ("PSC").

Q. DO YOU HAVE ANY COMMENTS REGARDING THE REFERENCE TO THE BG&E RATE CASE BEFORE THE MARYLAND PSC?

A. Yes. I would note that Mr. Johnson also filed testimony in that case and recommended allocating a portion of BG&E's meter costs using an energy allocation factor. This is different than the Maryland PSC Staff's meter cost allocation methodology proposed in the testimony cited in footnote 47 of Mr. Johnson's Initial Presentation. I would also note that this BG&E rate case was settled without adopting the Staff's proposed meter allocation methodology.

Q. IS THERE A SIMILAR ISSUE FOR THE ALLOCATION OF METER READING EXPENSES?

A. Yes. Mr. Johnson is proposing to allocate meter reading expenses using the same erroneous methodology he uses for allocating meter costs.

IV. ALLOCATION OF CUSTOMER SERVICE EXPENSES

Q. PLEASE DESCRIBE THE ICA'S PROPOSED ADJUSTMENT TO AE's ALLOCATION OF CUSTOMER SERVICE EXPENSES.

A. The ICA takes issue with AE's allocation of certain customer service expenses (FERC Accounts 911 through 917) on the basis of the number of customers in each customer class, Instead, Mr. Johnson recommends allocating customer service expenses "broadly across functions." To accomplish this, Mr. Johnson proposes to allocate 61% of all customer service expenses using an allocation factor based on each customer class's revenue requirement,

Q. DO YOU AGREE WITH MR. JOHNSON'S PROPOSED ALLOCATION OF AE's CUSTOMER SERVICE EXPENSES?

A. No. Mr. Johnson's proposal fails to recognize that a significant portion of AE's customer service expenses are identified as Key Accounts expenses. In AE's COSS, the Key Accounts expenses, which are primarily for larger commercial and industrial customers, are assigned to the customer classes based on a study that determined the amount of time Key Account customer service representatives spent with customers in each customer class. Mr. Johnson's allocation of 61% of customer service expenses on the basis of class revenue requirement will over-allocate expenses from the same accounts, i.e., Account 912, that included the Key Accounts expenses. AE's allocation of its customer service expenses provides for a more reasonable allocation and assignment of these expenses to the customer classes and the ICA's proposal should be rejected.

V. FUNCTIONALIZATION OF A&G EXPENSES

Q. PLEASE DESCRIBE THE ICA'S PROPOSED ADJUSTMENT TO AE's CLASSIFICATION OF ADMINISTRATIVE AND GENERAL ("A&G") EXPENSES.

A. Page 33, line 1, through page 37, line 5, of Mr. Johnson's Initial Presentation discusses the ICA's proposed adjustment to the functionalization of A&G expenses. The adjustment is to the functionalization of FERC Account No. 920, A&G salaries, and Account No. 930, Miscellaneous General Expenses. Regarding Account 920 expenses, Mr. Johnson disagrees with AE's functionalization factor which is based on labor expenses in each function, and with the amount AE directly assigns to the production function that are related to the South Texas Project ("STP") and the Fayette Power Plant ("FPP"). Instead, of the $3,334,160 that AE directly assigns to the production function for STP and FPP, Mr. Johnson proposes to directly assign $10,394,162.

Q. WHAT IS THE BASIS FOR MR. JOHNSON'S REVISED DIRECT ASSIGNMENT OF ACCOUNT 920 EXPENSES TO THE PRODUCTION FUNCTION?

A. Mr. Johnson's explanation of the calculation of his adjustment is that it effectively includes on-site labor expenses at STP and FPP in the production function payroll expenses for calculation of the payroll functionalization factors. Mr. Johnson's only basis for this adjustment is his belief that AE's functionalization factor understates the amount that should be functionalized to the production function.

Q. DO YOU AGREE WITH ICA'S PROPOSED FUNCTIONALIZATION OF ACCOUNT 920 EXPENSES?

A. No. Mr. Johnson has not shown that AE's Chief Executive Officer ("CEO") and other top administrators directly supervise non-AE employees onsite at SPP and FPP. Since AE does not operate or maintain either of those two power plants, it is unlikely that AE executives supervise the non-AE on-site employees. The majority owners of those two power plants do that and typically the minority owners of power plants pay the majority owners for their A&G expenses. The ICA's proposed adjustment will result in too much of the Account 920 expenses being functionalized as production-related and should be rejected.

VI. ICA'S PROPOSED REVENUE DISTRIBUTION

Q. PLEASE DESCRIBE THE ICA'S PROPOSED REVENUE DISTRIBUTION METHODOLOGY FOR ASSIGNING AE'S REVENUE INCREASE TO THE CUSTOMER CLASSES.

A. ICA's proposed revenue distribution methodology is discussed on page 56, line 19, through page 57, line 9, of Mr. Johnson's Initial Presentation. The ICA revenue distribution methodology is a two-step method. For the first step, all customer classes whose current rates are above their cost of service, receive a percent increase in their base rates that is one-half the average system percent increase. At AE's proposed revenue requirement, the average system precent increase is 7.6%, so the customer classes that are already above system cost of service will receive a 3.8% base rate revenue increase. In the second step, the ICA first determines the remaining amount of the total AE proposed revenue increase after the reduction for the over-recovery or subsidies from the customer classes receiving revenue increases in the first step. The ICA then distributes this remaining revenue increase amount on an equal percentage basis to the customer classes whose current base rate revenues are below their cost of service.

Q. DO YOU AGREE WITH ICA'S REVENUE DISTRIBUTION PROPOSAL?

A. No. I have three primary issues with ICA's proposal. My first problem is with the ICA's first step. In its first step, the ICA proposal would increase the current rate revenue levels of the customer classes whose current rates already over-recover their allocated cost of service. In other words, the ICA would move these customer classes' revenue levels even farther above their cost of service, i.e., this would increase the subsidies to other classes that they already pay under current rates. My second problem is that the results of ICA's two-step revenue distribution at ICA's proposed revenue requirement results in very little movement toward each class's allocated cost of service. This is shown on ICA Schedule CJ-4. For example, the City Outdoor Lighting customer class would only receive a 1.2% base rate revenue increase. However, under ICA's adjusted COSS at ICA' proposed revenue requirement, the City Outdoor Lighting customer class would need a 102.1% base rate increase to pay its cost of service. My third issue is that Mr. Johnson does not present the results of his adjusted COSS at the ICA's reduced revenue requirement. He only shows the results of his adjusted COSS at AE's proposed revenue requirement. That analysis only shows two customer classes needing rate decreases and getting lower rate increases than the other customer classes under his proposed revenue distribution methodology. If Mr. Johnson had used ICA's reduced revenue requirement, additional customer classes may qualify for the lower percent rate increase category.

Q. DOES THE ICA OFFER REASONS OTHER THAN RATE IMPACTS FOR APPLYING GRADUALISM IN THE REVENUE DISTRIBUTION?

A. Yes. On page 55, line 10, through page 56, line 5, the ICA offers an additional reason for applying gradualism in this case. First, the ICA provides significant changes (increases and decreases) in customer class energy and demand allocation factors from AE's 2016 rate case to this rate case. The ICA implies that these allocation factor changes were caused by COVID and that the changes could recede in the future. In support of that claim, ICA refers to a S&P Global Credit Rating Report that discusses a decline in commercial customer sales and an increase in residential customer sales in Fiscal Year 2020 ("FY 2020").

Q. DO YOU AGREE WITH THIS ICA REASONING?

A. No. First, the S&P Global Credit Rating Report was for FY 2020. The test year in this rate case is FY 2021, after many of the business closures and lockdowns had ceased. In addition, much of the increase in residential energy usage was due to the substantial residential customer growth, as shown in my Table 5 of NXP's Position Statement. ICA has not quantified how much of the increase in the residential class allocation factors is due to customer growth and how much is due to COVID.

In addition, the ICA's argument fails to recognize the increase in the residential billing determinants since AE's last rate case. The residential customer charge billing determinants increased 24.0% and the energy charge billing determinants increased 18.2%. Although the residential class was allocated a higher percentage of the costs, the even greater percent increase in billing determinants will partially offset the impact of the increase in the allocation factors in the rate calculations.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING ICA'S PROPOSED CUSTOMER CLASS REVENUE DISTRIBUTION?

A. Yes. Regarding moving customer classes closer to their cost of service, I would note that in Docket No. 40627, the PUC Staff witness recommended a 20% class revenue increase cap to reduce rate shock on certain AE customer classes. This is significantly higher than the 1.2% rate increase cap proposed by the ICA.

VII. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. Based on my review and analysis, I have reached the following conclusions and recommendations:

(1) ICA witness Clarence Johnson improperly recommends the use of the base-intermediate-peak ("BIP") cost allocation methodology for allocating AE's production demand-related costs.

(2) The ICA incorrectly allocates a portion of the costs of smart meters to all customer classes based on a class revenue requirement allocation factor on the assumption that smart meters provide benefits to all customers.

(3) The ICA incorrectly allocates a portion of customer service expenses based on a customer class revenue requirement allocation factor.

(4) The ICA incorrectly functionalizes too much executive salaries in Account 920 to the production function. allocates distribution load dispatch expenses on the basis of energy.

(5) The ICA's proposed methodology for distributing the AE revenue increase to the customer classes is flawed and should not be approved.

Q. DOES THIS CONCLUDE YOUR CROSS-REBUTTAL POSITION STATEMENT?

A. Yes, it does.

EXHIBITS

SOAH DOCKET NO. 473-13-0935
PUC DOCKET NO. 40627

PETITION BY HOMEOWNERS UNITED FOR RATE FAIRNESS TO REVIEW AUSTIN RATE ORDINANCE NO. 20120607-055	§ § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

REBUTTAL TESTIMONY

OF

JOSEPH A. MANCINELLI

ON BEHALF OF THE CITY OF AUSTIN D/B/A AUSTIN ENERGY

FEBRUARY 22, 2013

Fourth, misclassification of fixed costs as energy-related is contrary to AE's business conservation, energy efficiency, and renewable energy business objectives.

Fifth, misclassification of fixed costs as energy-related results in significant double-dipping. As I will point out later in my testimony, OPC recommends a variety of production demand-related allocation techniques that further allocate fixed costs to the various rate classes based on energy. The two techniques pancaked on top of each other severely, and inappropriately, tilt the allocation of production fixed costs towards energy.

III. <u>ALLOCATION OF THE PRODUCTION FUNCTION</u>

Q. DF SUPPORTS THE USE OF THE A&E-4CP METHOD IN THIS PROCEEDING, IS THAT CORRECT?

A. Yes, with some minor exceptions to the calculation.

Q. PLEASE DESCRIBE THOSE EXCEPTIONS.

A. DF recommends that the A&E-4CP system load factor be calculated using the 1CP rather than the 4CP and that negative excess demands associated with the various lighting classes be set to zero.

Q. DO YOU AGREE WITH THESE RECOMMENDATIONS?

A. No. The Commission's adopted calculation uses 4CP, not 1CP, to calculate the system load factor. The use of 4CP simply aligns the system load factor calculation with the class load factor calculation. The 4CP reflects an average peak month during the summer season. On a going forward basis, the calculation of class and system peak based on a four-month average is a more stable and better indicator of system and class load factor than a single month or 1CP. The use of 4CP is comparable to use of 1CP with the added improvement of stability as both class and system peaks reflect the average peak, rather than the peak day. The Commission's use of 4CP in the calculation of system load factor is appropriate and should not be changed to 1CP, as suggested by DF.

With respect to negative excess demand, AE acknowledges that Commission precedent is to zero out negative excess demands as suggested by DF. However, allowing the negative excess demands to remain in the calculation provides some recognition of the nature of the demands placed on the system by the lighting classes, which are largely off-peak. The result happens to be mathematically equivalent to 4CP, but 4CP is also an acceptable production demand allocator.

Q. WHAT IS PUC STAFF'S POSITION ON THE A&E-4CP ALLOCATOR?

A. PUC Staff witness Abbott supports the use of the A&E-4CP allocation method calculated in accordance with prior Commission precedent.[11]

Q. WHAT IS THE IMPACT OF AE'S VARIATION FROM THE COMMISSION'S ADOPTED A&E-4CP CALCULATION?

A. The overall impact on the A&E-4CP calculation is very small as shown in Table 2, below.

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[11] Direct Testimony of William B. Abbott at 12-13 (Feb. 14, 2013).

Table 2 – Comparison of A&E-4CP

Class	PUC A&E-4CP	AE A&E-4CP	Alloc Diff
Residential	39.40%	39.51%	-0.11%
Secondary Voltage < 10 kW	3.56%	3.57%	-0.01%
Secondary Voltage 10 - 49.9 kW	9.44%	9.46%	-0.02%
Secondary Voltage ≥ 50 kW	34.25%	34.33%	-0.07%
Primary Voltage < 3 MW	2.71%	2.71%	0.00%
Primary Voltage 3 - 19.9 MW	4.17%	4.17%	0.00%
Primary Voltage ≥ 20 MW	5.00%	5.00%	0.00%
Transmission Voltage	1.22%	1.22%	0.00%
Service Area Lighting	0.16%	0.00%	0.15%
AE-Owned Private Outdoor Lighting	0.06%	0.00%	0.06%
Customer-Owned Non-Metered Lighting	0.01%	0.00%	0.01%
Customer-Owned Metered Lighting	0.02%	0.02%	0.01%
Total	100.00%	100.00%	0.00%

As one might expect, this change has the greatest impact on the lighting classes. Zeroing out negative excess demands increases the cost of service to the lighting classes.

Q. **GIVEN THAT SERVICE AREA LIGHTING IS THE LARGEST LIGHTING CLASS AND THAT THESE COSTS ARE RECOVERED THROUGH THE COMMUNITY BENEFIT CHARGE, WHAT IS THE IMPACT OF AE'S VARIATION FROM THE COMMISSION'S ADOPTED A&E-4CP CALCULATION ON EACH CLASS'S TOTAL COST?**

A. The impact on each customer class's total cost of service is shown in Table 3, below.

Table 3 – Impact of AE's Version of A&E-4CP

Class	Commission Adopted A&E-4CP	AE Recommended A&E-4CP	$ Difference	% Difference
Residential	456,244,908	456,402,485	(157,576)	-0.03%
Secondary Voltage < 10 kW	46,350,330	46,359,525	(9,195)	-0.02%
Secondary Voltage 10 - 49.9 kW	96,152,613	96,190,718	(38,105)	-0.04%
Secondary Voltage ≥ 50 kW	360,757,383	360,839,334	(81,951)	-0.02%
Primary Voltage < 3 MW	30,111,402	30,110,901	501	0.00%
Primary Voltage 3 - 19.9 MW	53,113,330	53,096,636	16,694	0.03%
Primary Voltage ≥ 20 MW	62,645,721	62,622,123	23,598	0.04%
Transmission Voltage	14,313,923	14,307,803	6,119	0.04%
Service Area Lighting	n/a	n/a	n/a	n/a
AE-Owned Private Outdoor Lighting	3,333,944	3,139,081	194,863	6.21%
Customer-Owned Non-Metered Lighting	130,980	103,703	27,277	26.30%
Customer-Owned Metered Lighting	469,671	451,895	17,776	3.93%
Total	1,123,624,205	1,123,624,205	-	0.00%

The strict adoption of the Commission's A&E-4CP would increase the AE-Owned Private Outdoor Lighting cost of service by 6.2%, the Customer-Owned Non-Meter Lighting cost of service by 26.3%, and the Customer-Owned Metering Lighting cost of service by 3.9%. Conversely, the corresponding impact on the other rate classes is de minimis. Given that this calculation difference impacts a small group of lighting customers adversely, while all remaining customers will see little to no change in their cost of service, AE recommends that the Commission approve AE's A&E-4CP calculation as presented in this proceeding.

Q. **OPC DISCUSSES A VARIETY OF ENERGY-WEIGHTED PRODUCTION FIXED COSTS ALLOCATION METHODS AND APPEARS TO RECOMMEND A HYBRID BASELOAD, INTERMEDIATE AND PEAKING ("BIP") METHOD OR AN AVERAGE AND PEAK METHOD. DO YOU AGREE WITH THIS RECOMMENDATION?**

A. No. OPC has proposed numerous cost allocation options for consideration in this case.[12] All options are similar in that they classify and/or allocate a significant portion of AE's production demand-related costs based on energy. The impact of this approach is a shifting of costs from low load factor customers to high load factor customers. It appears that cost shifting is the primary objective of these recommendations rather than the applicability of the method to AE. OPC mentions eight different approaches and considers six of these (all but the last two) to be appropriate for AE. These are as follows:

1. Average and Peak Demand ("APD") – This method treats generation plant in a homogenous fashion and divides fixed costs into two components based on system load factor. The energy component is equal to system load factor and is classified and allocated to each class based on energy. The demand component is equal to (1 - system load factor) and is allocated to each class based on some measure of peak demand.

2. Plant Capacity Factor ("PCF") – This method treats generation plant on a unit by unit basis. PCF allocates costs in alignment with plant capacity factor. If a plant exhibits a 60% capacity factor, then 60% of the costs will be allocated based on energy. The demand component is equal to (1 - unit capacity factor) and is allocated to each class based on some measure of peak demand.

3. Peaker Credit ("PC") – This method treats generation plant on a unit by unit basis. PC values the capacity benefit associated with a generation unit based on combustion turbine ("CT") as this theoretically represents the value of the most efficient capacity resource. Capacity value is allocated to each class based on some measure of peak demand. The remaining fixed costs (actual costs less cost of a CT) are allocated to each class based on energy.

4. Baseload, Intermediate and Peak ("BIP") – This method treats generation plant by design configuration and allocated costs to base, intermediate and peak time periods.

5. Hybrid BIP ("HBIP") – This method treats generation plant on a design configuration basis. This is similar to BIP but adjusts the baseload component using the PCF method. The demand component is allocated using the 4CP.

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[12] Direct Testimony of William B. Marcus at 13-16 (Feb. 7, 2013).

6. Nuclear Only ("NO") – This method allocates STP using the PCF method and then allocates the remaining fixed costs associated with other AE generation as a lump sum using 4CP.

7. Probability of Dispatch – This method allocates fixed generation costs using an hourly dispatch analysis that meets load requirements with generation assets.

8. Marginal Cost – This cost of service method allocates costs to classes based on the marginal cost of serving the next increment of demand, energy, and customer.[13]

Q. DID AE CONSIDER ANY OF THESE METHODS IN THE RATE REVIEW PROCESS?

A. Yes. As described in my direct testimony, AE considered the 4CP, A&E, and BIP methodologies during the rate review process.[14] Based on this review, the A&E method was selected as the preferred method as it aligned well with AE's strategic plan and related objectives. The December 19, 2011 Rate Analysis and Recommendations Report ("RARR") summarizes the reasoning supporting this conclusion.[15]

In further deliberations, the City Council accepted the A&E methodology as being fair and reasonable considering both demand and energy components associated with generation. However, the City Council modified the analysis to substitute 4CP in place of non-coincident peak ("NCP"). The class contribution to the system peak is a more important cost causal relationship than the class NCP. The modified approach simply reflects the logical allocation of production fixed costs in two steps: 1) use a system and class load factor to identify customer and system energy and demand components, and 2) allocate the energy component to each

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[13] *Id.* at 19-21.

[14] Direct Testimony of Joseph A. Mancinelli at 43-44 (Nov. 1, 2012).

[15] *Id.* at Exhibit JAM-2, page 22.

customer class using average demand and the demand component (1 - system load factor) to each customer class using the 4CP. The recognition of AE's significant summer peak, and its impact on generation costs, was influential in the development of the allocation factor.

Q. **WHY SHOULD OPC'S PROPOSED METHODS BE REJECTED BY THE COMMISSION?**

A. OPC's various methods do not reflect an improvement in the allocation of production fixed costs to the various customer classes compared to the A&E-4CP methodology. OPC's recommended methods weigh the energy component of production demand-related costs too heavily and do not properly recognize the value of generation during the peak summer pricing period. The summer peak in the Electric Reliability Council of Texas ("ERCOT"), as with AE, is significant. To meet this peak the ERCOT market and AE must secure capacity. Meeting the summer peak drives generation investment. Further, class contribution to the peak is an important and strong cost causation factor. At an even more fundamental level, class load factor drives system costs. This point is confirmed when comparing the A&E method using NCP to allocate peak demand costs with the A&E-4CP method as shown in Table 4, below.

Table 4 – Comparison of A&E-4CP and A&E NCP

Class	A&E (NCP)	A&E (4CP)	Alloc Diff
Residential	41.2%	39.4%	1.8%
Secondary Voltage < 10 kW	3.5%	3.6%	-0.1%
Secondary Voltage 10 - 49.9 kW	9.0%	9.4%	-0.4%
Secondary Voltage ≥ 50 kW	32.7%	34.3%	-1.6%
Primary Voltage < 3 MW	2.6%	2.7%	-0.1%
Primary Voltage 3 - 19.9 MW	4.2%	4.2%	0.1%
Primary Voltage ≥ 20 MW	4.9%	5.0%	-0.1%
Transmission Voltage	1.2%	1.2%	-0.1%
Service Area Lighting	0.3%	0.2%	0.2%
AE-Owned Private Outdoor Lighting	0.2%	0.1%	0.1%
Customer-Owned Non-Metered Lighting	0.0%	0.0%	0.0%
Customer-Owned Metered Lighting	0.1%	0.0%	0.1%
Total	100.0%	100.0%	0.0%

Not surprisingly, for most customer classes, the two methods yield similar results as class load factor drives system load factor, and system load factor drives peak demand. So production demand allocation using A&E-NCP creates a result similar to A&E-4CP.

Q. MR. MARCUS ARGUES THAT THE A&E METHODOLOGY DOES NOT PROPERLY REFLECT AVERAGE DEMAND BUT IS RATHER A PEAK DEMAND RESPONSIBILITY METHOD IN DISGUISE. DO YOU AGREE?

A. No. As stated in the NARUC manual:

> The cost of service analyst may believe that average demand … is a better allocator of production plant costs. The average and excess method is an appropriate method for the analyst to use. The method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands.[16]

[16] National Association of Regulatory Utility Commissioners ("NARUC"), Electric Utility Cost Allocation Manual at 49 (Jan. 1992).

As previously discussed, the A&E-NCP method referenced in the NARUC quotation, yields a similar result when compared to the A&E-4CP method. Both the A&E-NCP and A&E-4CP methods consider the impact of class load factor on system demand requirements. Load factor is a measure of efficiency and considers the relationship between demand and energy consumption. Thus, the various A&E methods appropriately consider average demands.

Q. WHY DO OPC'S PROPOSED ALLOCATION METHODS VARY SUBSTANTIALLY FROM RESULTS DERIVED FROM THE A&E-NCP AND A&E-4CP METHODS?

A. OPC's proposed allocation methods vary substantially from the various A&E methods because the methods proposed, in essence, reclassify generation plant as energy-related. This reclassification shifts costs to high load factor customers. Under the A&E method, high load factor classes are rewarded for their efficiency. High load factor classes have relatively little excess demand compared to low load factor classes and are, therefore, allocated a smaller share of excess demand costs. Under OPC's various allocation approaches, high load factor customers are penalized. OPC recommends treatment of production demand costs as energy and allocates a significant portion of these cost based on energy. High load factor customers are using utility plant in a highly efficient manner, and are the most cost effective to serve. The A&E method recognizes this, but the various OPC proposals do not.

Q. WHY IS THE APD METHOD NOT APPROPRIATE TO USE IN THIS PROCEEDING?

A. OPC's APD method should be rejected because, unlike the A&E method, the APD method classifies the average demand component of the calculation as energy. In other words, it again misclassifies production fixed costs as being variable in nature. The NARUC Electric Utility Cost Allocation Manual, while describing the APD method, makes a note of this as follows:

> ...although classifying the system load factor percentage as energy-related might not affect the allocation among classes, it could significantly affect the apportionment of costs within rate classes. Such a classification could also affect the allocation of production plant costs to interruptible service, if the utility or the regulatory authority allocated energy-related production plant costs but not demand-related production plant costs to the interruptible class.[17]

This provision demonstrates that classifying fixed costs as energy skews both the allocation of costs between classes and distorts the pricing signals given through rate design.

The A&E method differs from this approach as the class allocator reflects the class load factor and its relationship to the system load factor. Under A&E, high load factor classes compared to low load factor classes are allocated less fixed costs in recognition of their highly efficient use of power. However, under the APD methodology the exact opposite result occurs. High load factor customers are allocated more fixed costs because they consume a high amount of energy compared to the capacity requirements placed on the system. For this reason, ADP is not a very good allocator of fixed demand-related generation costs. Therefore, the APD method should be rejected because it misclassifies costs.

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[17] *Id.* at 51.

Q. DIDN'T AE SERIOUSLY CONSIDER USING THE BIP METHOD IN THE ALLOCATION OF GENERATION COSTS?

A. Yes, the BIP method has already been thoroughly vetted and rejected in a lengthy public process as described in my direct testimony as well as the direct testimony of Mr. Dreyfus. Because the BIP method allocates baseload units on energy, the capacity value associated with these units is spread over all hours in the year. This approach undervalues capacity associated with these units during peak pricing and peak demand periods. The BIP method focuses on generation supply rather than customer demand. The BIP method ignores system and class load factors which drive capacity costs. This approach does not align with AE's objectives of sending pricing signals to customers that promote conservation and energy efficiency. Finally, if the BIP method is used and baseload units are classified as energy-related, similar to the APD approach, this improper misclassification will distort the pricing signal by lowering demand charges and raising energy charges. This distorted pricing signal will further weaken AE's ability to recover fixed costs. For all these reasons, the BIP method should be rejected by the Commission.

Q. PLEASE COMMENT ON THE REMAINING ALLOCATION METHODS RECOMMENDED BY OPC.

A. OPC's proposed PC, HBIP, and NO methods value capacity at the theoretical cost of a CT as a CT represents the cost of efficient capacity. The remaining fixed costs over and above the cost of a CT are then allocated to customer classes based on energy. OPC argues that high fixed cost baseload generation, such as STP and FPP, are designed to produce low cost energy. However, this combination, high fixed costs and low energy costs, only makes economic sense at high capacity factors. Baseload units typically run at annual capacity factors that are greater than 80%. At high capacity factors, bascload unit costs are competitive compared to other technologies. Aligning this cost causation relationship (high fixed costs and low variable costs) with cost allocation and rate design is important as it aligns the pricing signal to customers with cost causation and protects AE against the under-recovery of fixed costs.

Under the PC, HBIP and NO methodologies, a significant portion of fixed costs are either classified or allocated based on energy. These approaches do not recognize the benefit these units provide in meeting the system peak. As a result, these approaches diminish the summer versus non-summer pricing differentials as they spread fixed costs over all pricing periods and undermine pricing signals that encourage efficient use of plant.

Q. OPC ARGUES THAT THE CLASS CONTRIBUTION TO THE ERCOT 4CP SHOULD BE USED INSTEAD OF THE AE SYSTEM 4CP. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. Although it is proper to allocate transmission matrix expenses using the ERCOT 4CP, it is not proper to use the ERCOT 4CP in the allocation of production fixed costs. In the case of transmission, the underlying cost driver is clearly the ERCOT 4CP. Austin Energy is allocated its prorated share of transmission matrix expenses based on its contribution to the ERCOT 4CP. In this case, cost causation is in alignment with cost allocation. However, in the case of production fixed costs, these costs have been historically incurred to serve AE's load with the primary concern of meeting AE's peak demand. Even under the current ERCOT Nodal Market, AE's generation fleet acts as a hedge against fluctuations in the market pricc. Austin

Energy's exposure to market prices is directly related to purchasing power from the market to serve native load. Therefore, AE's system load is the primary driver of costs. To preserve the relationship between cost causation and cost allocation, the AE system peak expressed as the 4CP must be used. Further, since A&E-4CP allocation method is primarily concerned with system and customer class load factors, these characteristics can only be properly determined using the AE system 4CP. Therefore, OPC's recommendation to use the ERCOT 4CP rather than the AE system 4CP should be rejected.

IV. ALLOCATION OF THE DISTRIBUTION FUNCTION

Q. OPC RECOMMENDS USING 1 NON-COINCIDENT PEAK ("1NCP") TO ALLOCATE TRANSFORMER COSTS RATHER THAN SUM OF MAXIMUM DEMANDS ("SMD"), DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. SMD is a measure of customer demand at the meter. For commercial customers, SMD is equivalent to billed demand. SMD is the primary driver of transformer costs as transformers must be sized to meet or exceed customer demands placed upon them, otherwise, transformers will overload and reliability problems will result. OPC points out that, typically, several residential customers are served by a single transformer. This is in fact the case as AE, on average, serves about 5.5 residential customers per transformer. Further, on an annual average basis, a residential customer's peak demand varies between 4.9 kW to 5.5 kW. Therefore, in total, considering an average transformer serves 5.5 customers with an average peak demand ranging from 4.9 kW to 5.5 kW, the total demand on a single transformer, assuming zero diversity among the loads, yields a total demand ranging from 26.95 kW to 30.25 kW. This

RAC WORKING GROUP:
ALLOCATING REVENUE REQUIREMENTS TO CUSTOMER GROUPS

PRESENTED BY:

CPS Energy

September 23, 2021

Informational Update

OBJECTIVES & TAKEAWAYS

- **RECAP OUTPUT FROM COST OF SERVICE ANALYSIS**
- **SUMMARIZE ALLOCATION PROCESS**
- **SHOW COSTS ALLOCATED TO CUSTOMER GROUPS**
- **PROVIDE FULL COST OF SERVICE STUDY TO RAC MEMBERS**

AGENDA

- COS OUTPUT
- ALLOCATION PROCESS
- CUSTOMER COST ALLOCATION
- DEMAND COST ALLOCATION
- ENERGY COST ALLOCATION

Once the budgeting process is finished and our forward looking revenue requirements are defined, our backward looking, normalized Cost of Service study is used to appropriately, proportionately spread incremental revenue requirements to each customer group.

REVENUE VS. COST BY CUSTOMER GROUP (FY2017)

$ in thousands

Revenues

		Residential		PL		LLP		ELP		SLP	
Fixed	Customer	$ 69,207	7%	$ 8,032	2%	$ 4,149	2%	$ 2,035	2%	$ 448	0%
	Demand	136	0%	-	0%	66,547	25%	31,418	26%	50,991	30%
Variable	Energy	737,804	93%	361,858	98%	134,192	74%	55,188	72%	68,807	69%
	Energy (fuel adj)	121,237		62,344		40,485		19,594		31,374	
	Energy (reg adj)	103,917		36,071		23,680		10,326		16,111	
	Total	**$ 1,032,301**	**100%**	**$ 468,305**	**100%**	**$ 269,052**	**100%**	**$ 118,560**	**100%**	**$ 167,731**	**100%**

Cost to Serve

		Residential		PL		LLP		ELP		SLP	
Fixed	Customer	$ 184,004	17%	$ 37,503	9%	$ 7,061	3%	$ 1,817	2%	$ 2,862	2%
	Demand	472,529	43%	185,514	43%	109,279	44%	45,246	41%	65,160	38%
Variable	Energy	209,734	40%	107,853	48%	70,024	54%	33,862	58%	53,953	60%
	Energy (fuel adj)	121,237		62,344		40,485		19,594		31,374	
	Energy (reg adj)	103,917		36,071		23,680		10,326		16,111	
	Total	**$ 1,091,421**	**100%**	**$ 429,285**	**100%**	**$ 250,529**	**100%**	**$ 110,845**	**100%**	**$ 169,459**	**100%**

	Residential	PL	LLP	ELP	SLP
% Cost to Serve	**95%**	**109%**	**107%**	**107%**	**99%**

Notes: Based on normalized data (i.e., total revenue = total cost to serve).

COST BY CUSTOMER GROUP

Cost to Serve

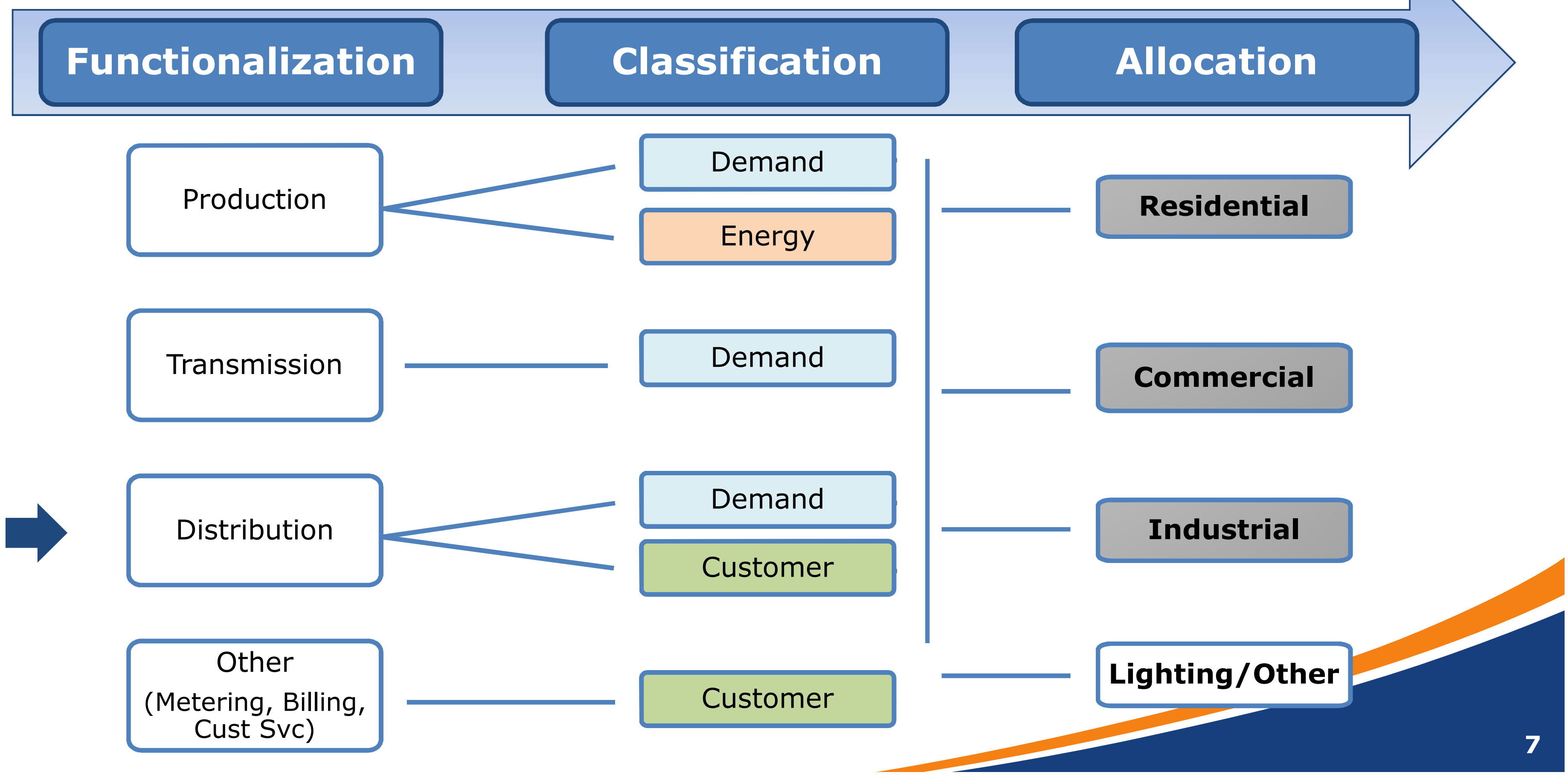
$ in thousands

		RESIDENTIAL	PL	LLP	ELP	SLP	SUM
Fixed	Customer	$184,004	$37,503	$7,061	$1,817	$2,862	$233,247
	Demand	472,529	185,514	109,279	45,246	65,160	877,728
Variable	Energy	209,734	107,853	70,024	33,862	53,953	475,426
	Energy (fuel adj)	121,237	62,344	40,485	19,594	31,374	275,034
	Energy (reg adj)	103,917	36,071	23,680	10,326	16,111	190,105
	Sum	**$1,091,421**	**$429,285**	**$250,529**	**$110,845**	**$169,459**	**$2,051,539**
% of Sum		**53%**	**21%**	**12%**	**5%**	**8%**	**100%**

To deliver the appropriate forecasted revenue requirement, we proportionally recover incremental revenue from each customer group.

Note: Cost to Serve dollar amounts can be traced to tab “12a-1. RevReq by class” of the Study.

FUNCTIONALIZATION & CLASSIFICATION



DISTRIBUTION SUBFUNCTIONALIZATION & CLASSIFICATION

	Substation		Demand
Lines	Poles	Primary/ Secondary	Min System -> Customer
			Demand
		Streetlights	DIRECT
	OH/UG Conductors	Primary/ Secondary	Min System -> Customer
			Demand
	UG Conduits	Primary/ Secondary	Demand
	Transformers		Min System -> Customer
			Demand
	Services		Customer
	Streetlights		DIRECT

ALLOCATION APPROACH DEPENDS ON THE TYPE OF COST

Focusing on Customer Costs

Cost to Serve

$ in thousands

		RESIDENTIAL	PL	LLP	ELP	SLP	SUM
Fixed	Customer	$184,004	$37,503	$7,061	$1,817	$2,862	$233,247
	Demand	472,529	185,514	109,279	45,246	65,160	877,728
Variable	Energy	209,734	107,853	70,024	33,862	53,953	475,426
	Energy (fuel adj)	121,237	62,344	40,485	19,594	31,374	275,034
	Energy (reg adj)	103,917	36,071	23,680	10,326	16,111	190,105
	Sum	**$1,091,421**	**$429,285**	**$250,529**	**$110,845**	**$169,459**	**$2,051,539**
% of Sum		**53%**	**21%**	**12%**	**5%**	**8%**	**100%**

First, we allocate customer costs to the customer groups.

Note: Cost to Serve dollar amounts can be traced to tab "12a-1. RevReq by class" of the Study.

CUSTOMER COSTS ALLOCATION

Focusing on Customer Costs

Customer-Related Costs from Cost of Service Study for FY2017

$ in thousands

			ALLOCATION					ALLOCATED COSTS				
Distribution	Costs	Allocation Method	Resi	PL	LLP	ELP	SLP	Residential	PL	LLP	ELP	SLP
Primary lines	$ 59,943	# Custs served thru pri lines	90%	9%	0.3%	0.02%	0.005%	$ 54,084	$ 5,689	$ 155	$ 14	$ 3
Secondary lines	$ 17,128	# Custs served thru sec lines	90%	9%	0.3%	0.02%	0.001%	$ 15,456	$ 1,626	$ 43	$ 4	$ 0
Transformers	$ 19,366	# Custs served thru sec lines	90%	9%	0.3%	0.02%	0.001%	$ 17,475	$ 1,838	$ 49	$ 4	$ 0
Services	$ 11,428	# Secondary custs, weighted	68%	21%	10%	1%	0.05%	$ 7,784	$ 2,456	$ 1,092	$ 89	$ 6
Customer Installation	$ 1,933	kWh @ generator	44%	23%	15%	7%	11%	$ 855	$ 439	$ 285	$ 138	$ 216
Metering												
Metering	$ 50,872	Meter costs	66%	28%	4%	0.4%	1%	$ 33,676	$ 14,266	$ 2,235	$ 199	$ 496
Meter Reading	$ 15,394	# Customers, weighted	81%	17%	2%	0.2%	0.04%	$ 12,394	$ 2,607	$ 355	$ 31	$ 7
Billing	$ 5,725	# Customers, weighted	75%	24%	1%	0.1%	0.02%	$ 4,300	$ 1,357	$ 62	$ 5	$ 1
Customer Service												
Phone/Office Contact	$ 33,579	# Customers, weighted	90%	9%	0.3%	0.02%	0.005%	$ 30,296	$ 3,187	$ 87	$ 8	$ 2
Public Awareness	$ 1,230	kWh @ generator	44%	23%	15%	7%	11%	$ 544	$ 280	$ 182	$ 88	$ 137
Marketing	$ 20,501	kWh @ generator	44%	23%	15%	7%	11%	$ 9,066	$ 4,662	$ 3,025	$ 1,459	$ 2,289
Other	$ (3,852)	Test Year basic revenue	50%	23%	13%	6%	8%	$ (1,925)	$ (903)	$ (508)	$ (220)	$ (296)
Total	**$ 233,247**							**$ 184,004**	**$ 37,503**	**$ 7,061**	**$ 1,817**	**$ 2,862**

Note: Information found on tab "12a-1. RevReq by class" of the COS Study.

RESULT OF COST ALLOCATION

Focusing on Customer Costs

Cost to Serve

$ in thousands

		RESIDENTIAL	PL	LLP	ELP	SLP	SUM
Fixed	Customer	$184,004	$37,503	$7,061	$1,817	$2,862	$233,247
	Demand	472,529	185,514	109,279	45,246	65,160	877,728
Variable	Energy	209,734	107,853	70,024	33,862	53,953	475,426
	Energy (fuel adj)	121,237	62,344	40,485	19,594	31,374	275,034
	Energy (reg adj)	103,917	36,071	23,680	10,326	16,111	190,105
	Sum	**$1,091,421**	**$429,285**	**$250,529**	**$110,845**	**$169,459**	**$2,051,539**
% of Sum		**53%**	**21%**	**12%**	**5%**	**8%**	**100%**

Allocation results in ~80% of the customer costs being built into residential rates ($184M out of $233M).

ALLOCATION APPROACH DEPENDS ON THE TYPE OF COST

Focusing on Demand Costs

Cost to Serve

$ in thousands

		RESIDENTIAL	PL	LLP	ELP	SLP	SUM
Fixed	Customer	$184,004	$37,503	$7,061	$1,817	$2,862	$233,247
	Demand	472,529	185,514	109,279	45,246	65,160	877,728
Variable	Energy	209,734	107,853	70,024	33,862	53,953	475,426
	Energy (fuel adj)	121,237	62,344	40,485	19,594	31,374	275,034
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	Sum	**$1,091,421**	**$429,285**	**$250,529**	**$110,845**	**$169,459**	**$2,051,539**
% of Sum		**53%**	**21%**	**12%**	**5%**	**8%**	**100%**

Next, we allocate demand costs.

DEMAND COST ALLOCATION

Focusing on Demand Costs

Demand-Related Costs from Cost of Service Study for FY2017

$ in thousands

	Costs	Allocation Method	ALLOCATION Resi	PL	LLP	ELP	SLP	ALLOCATED COSTS Residential	PL	LLP	ELP	SLP
Production Non-Fuel	$ 553,152	Average & Excess	53%	21%	13%	5%	8%	$ 292,590	$ 118,512	$ 69,531	$ 29,224	$ 43,296
Decommissioning	$ 30,340	Average & Excess	53%	21%	13%	5%	8%	$ 16,048	$ 6,500	$ 3,814	$ 1,603	$ 2,375
Transmission	$ 68,545	Avg Class CPs w/4 ERCOT CPs	53%	20%	14%	5%	8%	$ 36,211	$ 13,881	$ 9,319	$ 3,694	$ 5,440
Distribution												
Substations	$ 72,994	Class NCP	54%	21%	12%	5%	8%	$ 39,115	$ 15,562	$ 9,048	$ 3,750	$ 5,519
Primary lines	$ 106,016	Class NCP	54%	21%	12%	5%	8%	$ 56,810	$ 22,603	$ 13,142	$ 5,446	$ 8,016
Secondary lines	$ 28,853	Sum NCP thru sec lines	70%	17%	9%	3%	1%	$ 20,102	$ 5,008	$ 2,575	$ 875	$ 292
Transformers	$ 17,826	Avg of Class NCP & Sum NCP thru sec lines	65%	19%	10%	4%	1%	$ 11,653	$ 3,448	$ 1,850	$ 654	$ 221
Total	**$ 877,727**							**$ 472,529**	**$ 185,514**	**$ 109,279**	**$ 45,246**	**$ 65,160**

Note: Information found on tab "12a-1. RevReq by class" of the COS Study.

RESULT OF DEMAND COST ALLOCATION

Focusing on Demand Costs

Cost to Serve

$ in thousands

		RESIDENTIAL	PL	LLP	ELP	SLP	SUM
Fixed	Customer	$184,004	$37,503	$7,061	$1,817	$2,862	$233,247
	Demand	472,529	185,514	109,279	45,246	65,160	877,728
Variable	Energy	209,734	107,853	70,024	33,862	53,953	475,426
	Energy (fuel adj)	121,237	62,344	40,485	19,594	31,374	275,034
	Energy (reg adj)	103,917	36,071	23,680	10,326	16,111	190,105
	Sum	**$1,091,421**	**$429,285**	**$250,529**	**$110,845**	**$169,459**	**$2,051,539**
% of Sum		**53%**	**21%**	**12%**	**5%**	**8%**	**100%**

Allocation results in ~54% of the customer costs being built into residential rates ($473M out of $878M).

ALLOCATION APPROACH DEPENDS ON THE TYPE OF COST

Focusing on Energy Costs

Cost to Serve

$ in thousands

		RESIDENTIAL	PL	LLP	ELP	SLP	SUM
Fixed	Customer	$184,004	$37,503	$7,061	$1,817	$2,862	$233,247
	Demand	472,529	185,514	109,279	45,246	65,160	877,728
Variable	Energy	209,734	107,853	70,024	33,862	53,953	475,426
	Energy (fuel adj)	121,237	62,344	40,485	19,594	31,374	275,034
	Energy (reg adj)	103,917	36,071	23,680	10,326	16,111	190,105
	Sum	**$1,091,421**	**$429,285**	**$250,529**	**$110,845**	**$169,459**	**$2,051,539**
% of Sum		**53%**	**21%**	**12%**	**5%**	**8%**	**100%**

Lastly, we allocate the energy costs to each customer group.

ENERGY COSTS* ALLOCATION

Focusing on Energy Costs

Energy-Related Costs from Cost of Service Study for FY2017

$ in thousands

			ALLOCATION					ALLOCATED COSTS				
Production	Costs	Allocation Method	Resi	PL	LLP	ELP	SLP	Residential	PL	LLP	ELP	SLP
Non-Fuel	$ 116,024	kWh @ generator	44%	23%	15%	7%	11%	$ 51,307	$ 26,384	$ 17,121	$ 8,258	$ 12,954
Fuel	$ 359,403	kWh sales	44%	23%	15%	7%	11%	$ 158,427	$ 81,469	$ 52,904	$ 25,604	$ 40,999
Total	**$ 475,426**							**$ 209,734**	**$ 107,853**	**$ 70,024**	**$ 33,862**	**$ 53,953**

* Base rate energy costs only, excludes costs that are passed through via the adjustments clause in the rates (e.g. fuel adjustment, regulatory adjustment).

Note: Information found on tab "12a-1. RevReq by class" of the COS Study.

RESULT OF COST ALLOCATION

Focusing on Energy Costs

Cost to Serve

$ in thousands

		RESIDENTIAL	PL	LLP	ELP	SLP	SUM
Fixed	Customer	$184,004	$37,503	$7,061	$1,817	$2,862	$233,247
	Demand	472,529	185,514	109,279	45,246	65,160	877,728
Variable	Energy	209,734	107,853	70,024	33,862	53,953	475,426
	Energy (fuel adj)	121,237	62,344	40,485	19,594	31,374	275,034
	Energy (reg adj)	103,917	36,071	23,680	10,326	16,111	190,105
	Sum	**$1,091,421**	**$429,285**	**$250,529**	**$110,845**	**$169,459**	**$2,051,539**
% of Sum		**53%**	**21%**	**12%**	**5%**	**8%**	**100%**

Allocation results in ~45% of the customer costs being built into residential rates ($210M out of $475M).

Note: For FY2017. Based on normalized data

The next step of the process is to design the bill components to appropriately recover fixed vs. variable costs (i.e., customer costs, demand costs & energy costs).

We will cover this on October 14th.

Thank You

Appendix

COST ALLOCATION – INDUSTRY STANDARDS

Three sources of industry guidance on developing cost of service:

- **NARUC Electric Utility Cost Allocation Manual – Embedded Cost of Service**
- **PUCT Unbundled Cost of Service Guidance/Rules**
- **PUCT Transmission Cost of Service Rules**

Customers have unique profiles; they use electricity in different ways

CPS Energy uses all three of these to guide development of cost of service.

COST TO SERVE

Select Test Year & Collect Data

Accounting Data
Revenue · Expenses · Assets

Sales & Statistics
Load Research · Demand Study · Allocation Basis

Inputs

Functionalization of Costs
Production · Transmission · Distribution · Other

Classification of Costs
Customer · Demand (kW) · Energy (kWh)

Allocation of Costs
Residential · Commercial · Industrial · Other

Cost of Service

Development of Preliminary Revenue Requirements and Unit Prices for Each Class

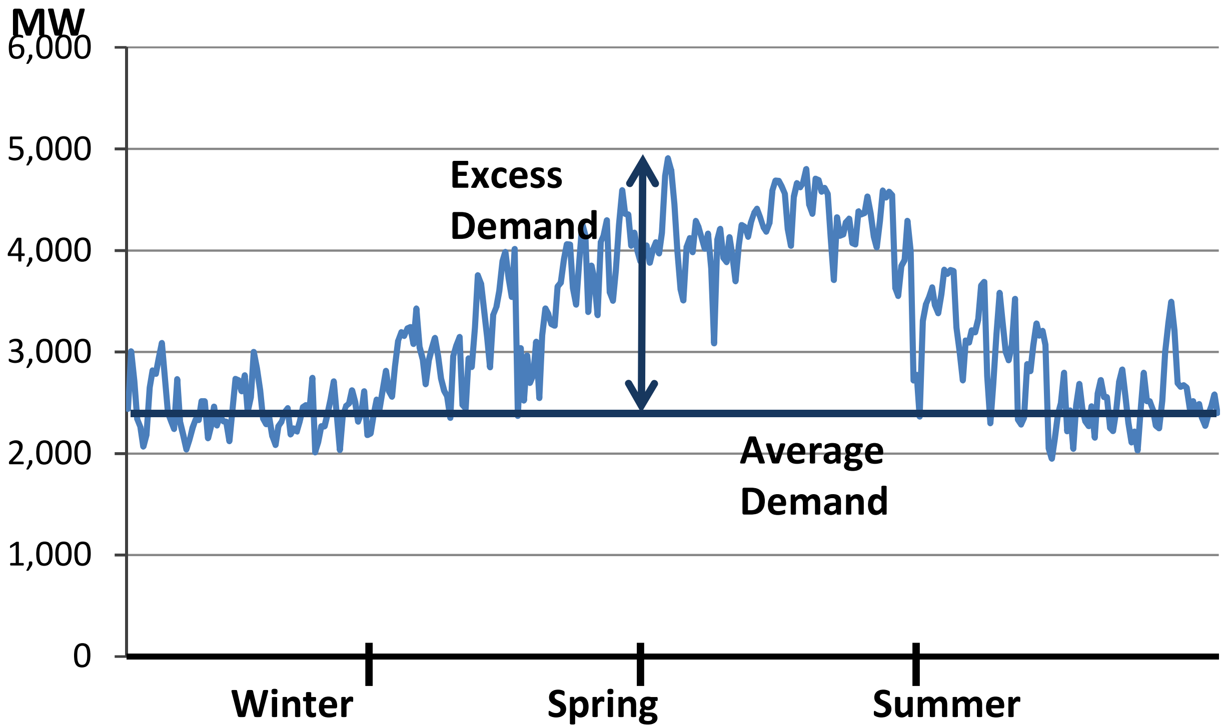
Results

Customer Costs:
- Fixed costs
- Billing system, call center, postage, metering

Demand Costs:
- Fixed costs
- Generators, wires, transformers, etc.

Energy Costs:
- Variable cost of producing energy
- Natural gas, labor, etc.

DEMAND ALLOCATION FACTORS
AVERAGE & EXCESS METHOD



Plotted values are maximum daily demands.

GENERATION UTILIZATION UPDATE

PRESENTED BY:

Kevin Pollo
Vice President, Energy Supply & Market Operations

May 26, 2022

Informational Update

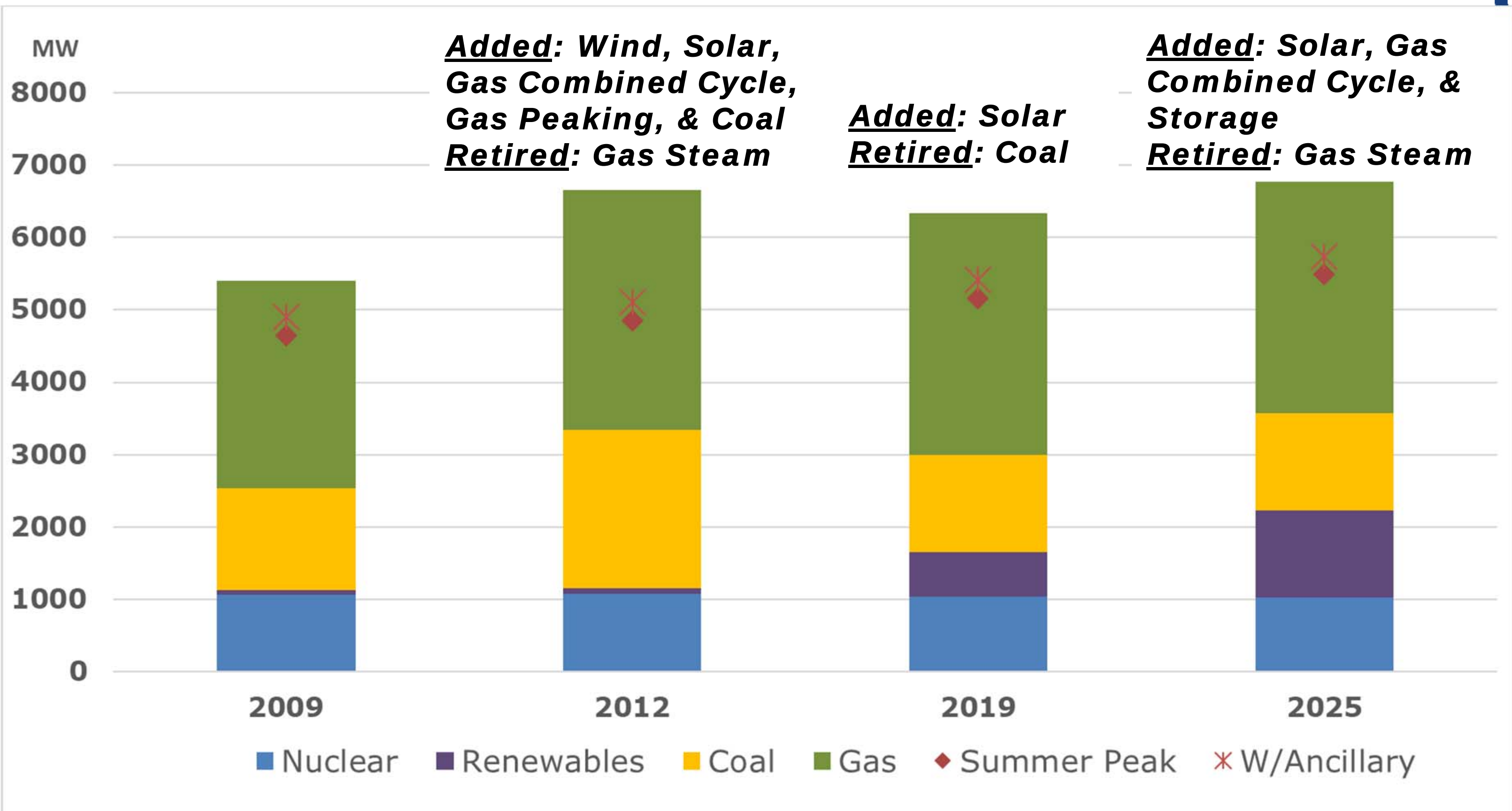
AGENDA

- PEAK PLANNING
- RESERVE MARGIN
- UTILIZATION UPDATE: ENERGY & ANCILLARY SERVICES

UNIQUE ASPECTS OF ELECTRICITY

- Electric supply must be produced & delivered in “real time” to meet demand
    - Electricity cannot be stored in large enough quantities
- Depending on the magnitude of the shortfall, there can be severe financial and/or reliability consequences if electric supply falls short of demand

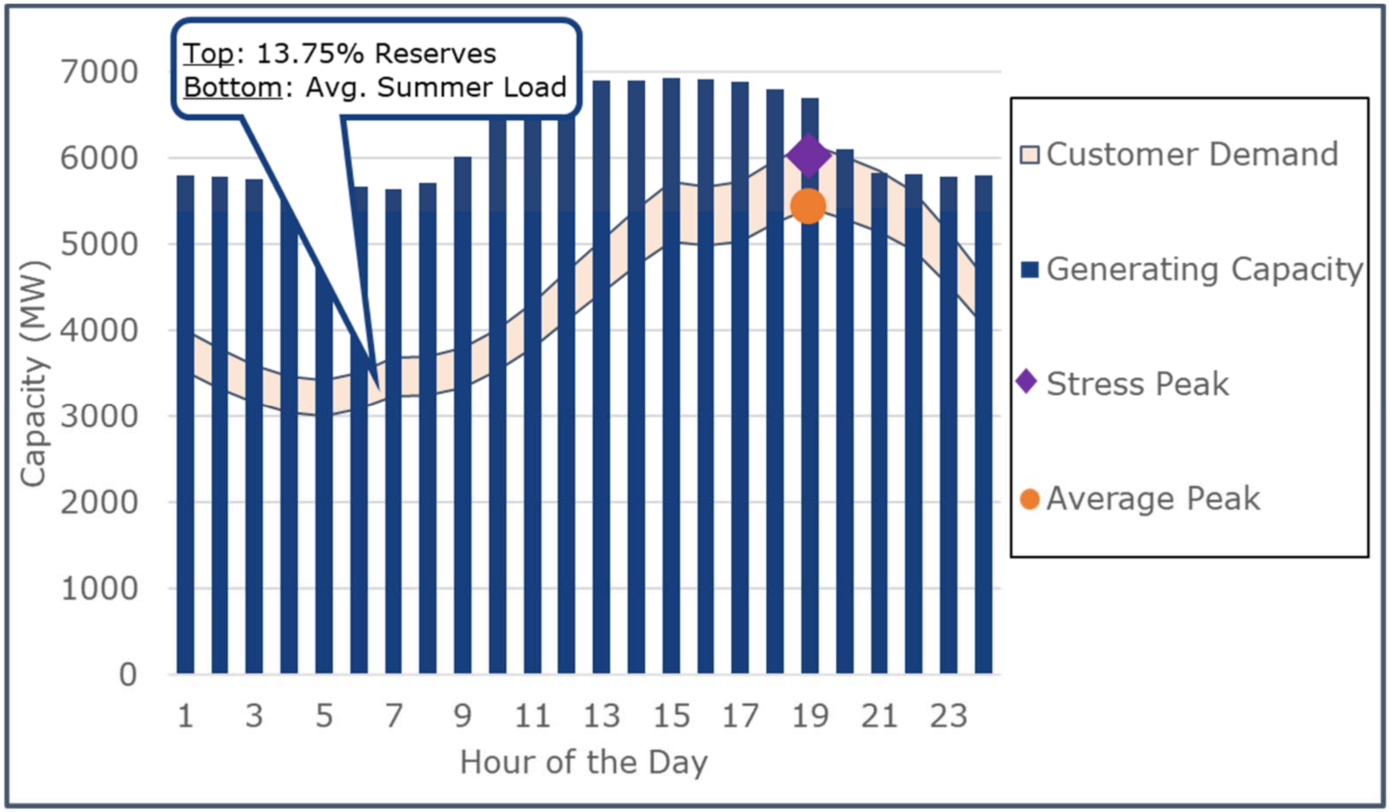
SUPPLY & DEMAND
AT SUMMER PEAK



Our generation planning strategy is to provide sufficient capacity to protect our customers from exposure to high market prices.

SUMMER DAY

2025 PROJECTION – DEMAND & SUPPLY



2025 Summer Forecast:

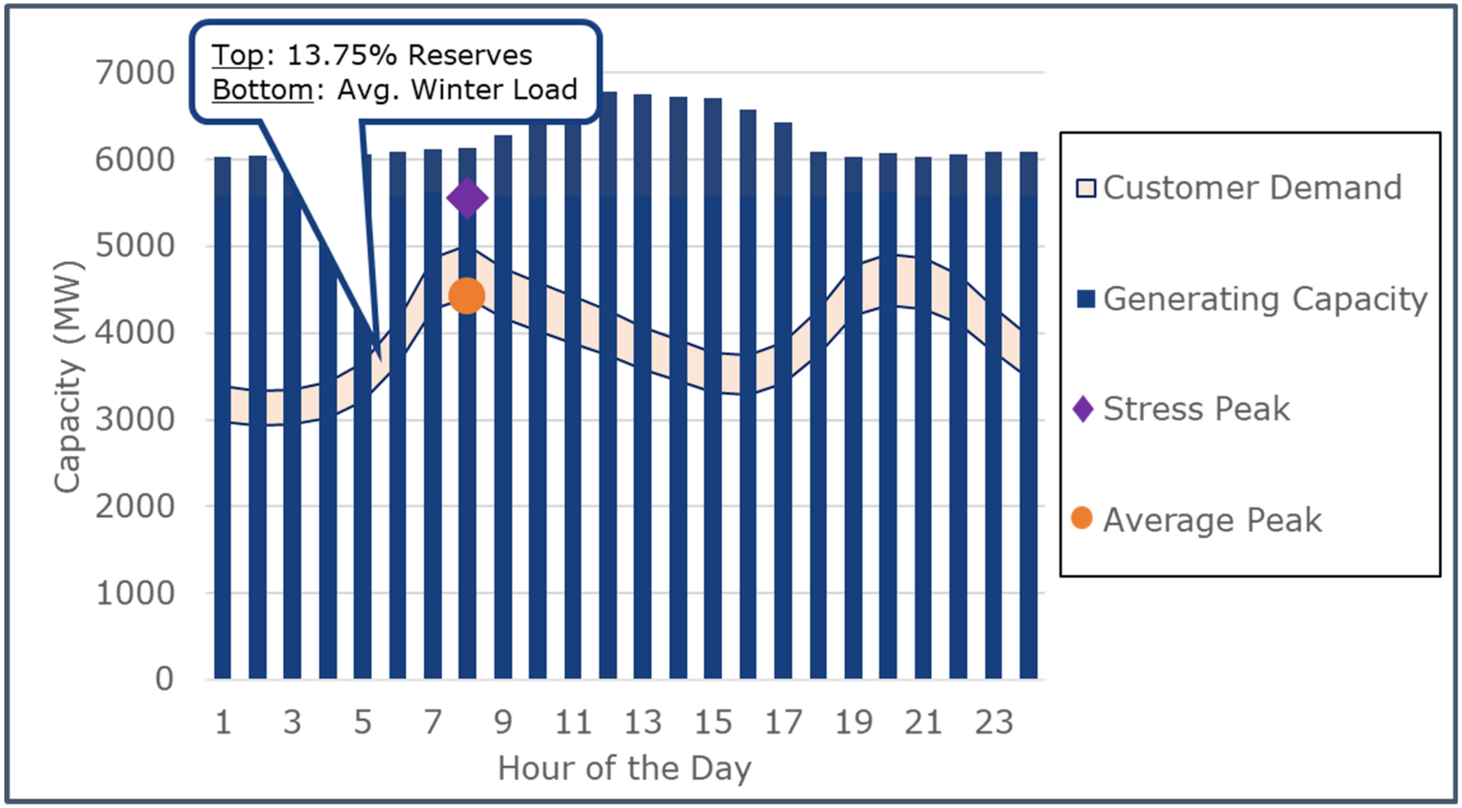
Demand:
- Avg. Peak: 5,424MW
- Stress Peak: 6,028MW

Supply:
- Nuclear, Coal, Gas, & Storage: 100%
- Coastal Wind: 57%
- West Wind: 20%
- Solar: 50%

All resources are utilized to meet summer peak demand.

WINTER DAY

2025 PROJECTION – DEMAND & SUPPLY



2025 Winter Forecast:

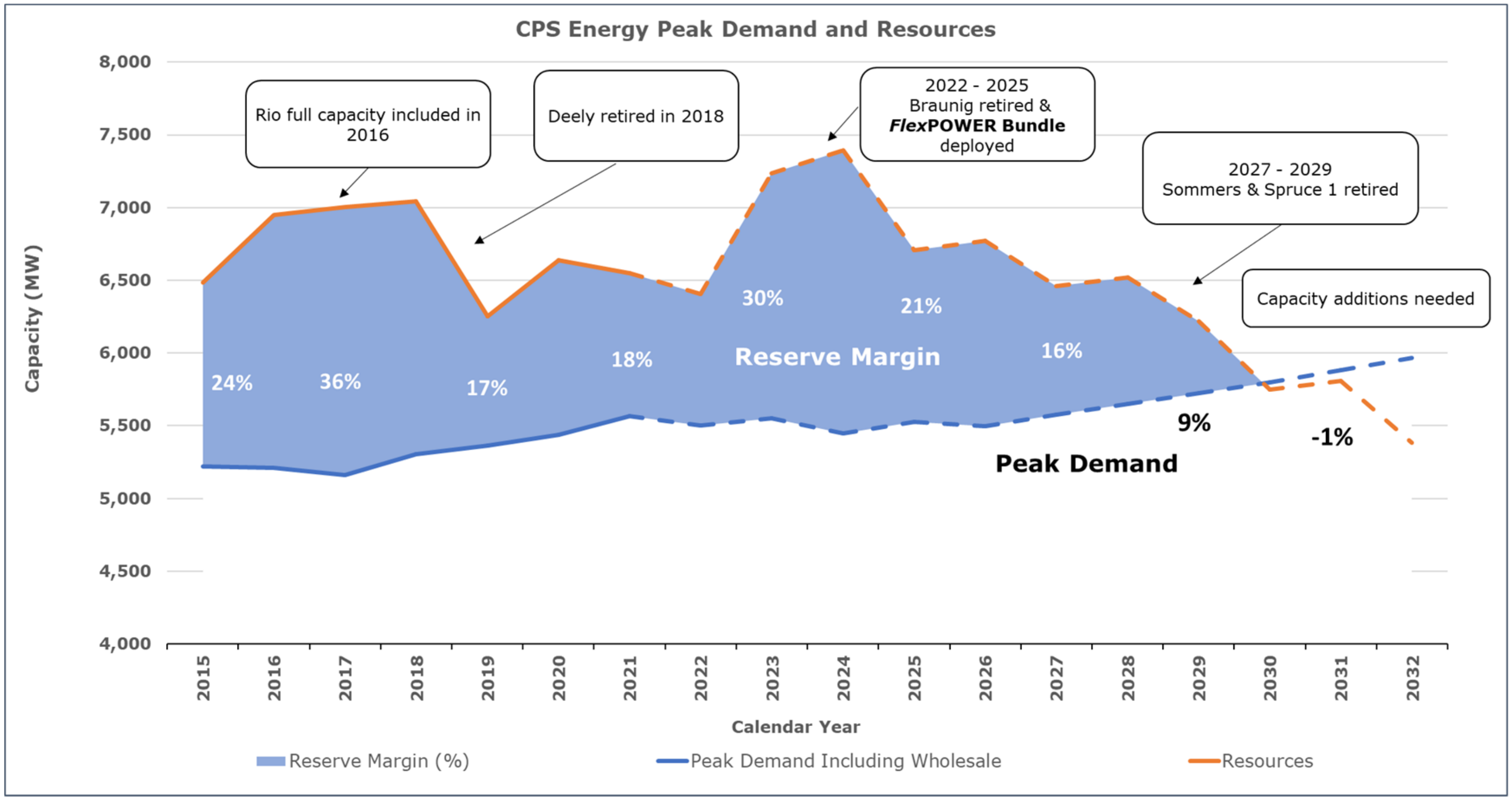
Demand:
- Avg. Peak: 4,411MW
- Stress Peak: 5,555MW

Supply:
- Nuclear, Coal, Gas, & Storage: 100%
- Coastal Wind: 43%
- West Wind: 19%
- Solar: 0.9%

All resources are utilized to meet extreme winter peak demand while average winter peak is less challenging.

OUR RESERVE MARGIN*

VIEW WITH NO ADDITIONS AFTER *FLEX*POWER BUNDLE℠



Reserve margin is the capacity needed to:

- ***Provide ancillary services.***
- ***Meet customer demand if power plants generate less than expected, or customer demand increases more than expected.***

* At summer peak, hour ending 7 p.m.

Our planning reserve margin floor is 13.75%.

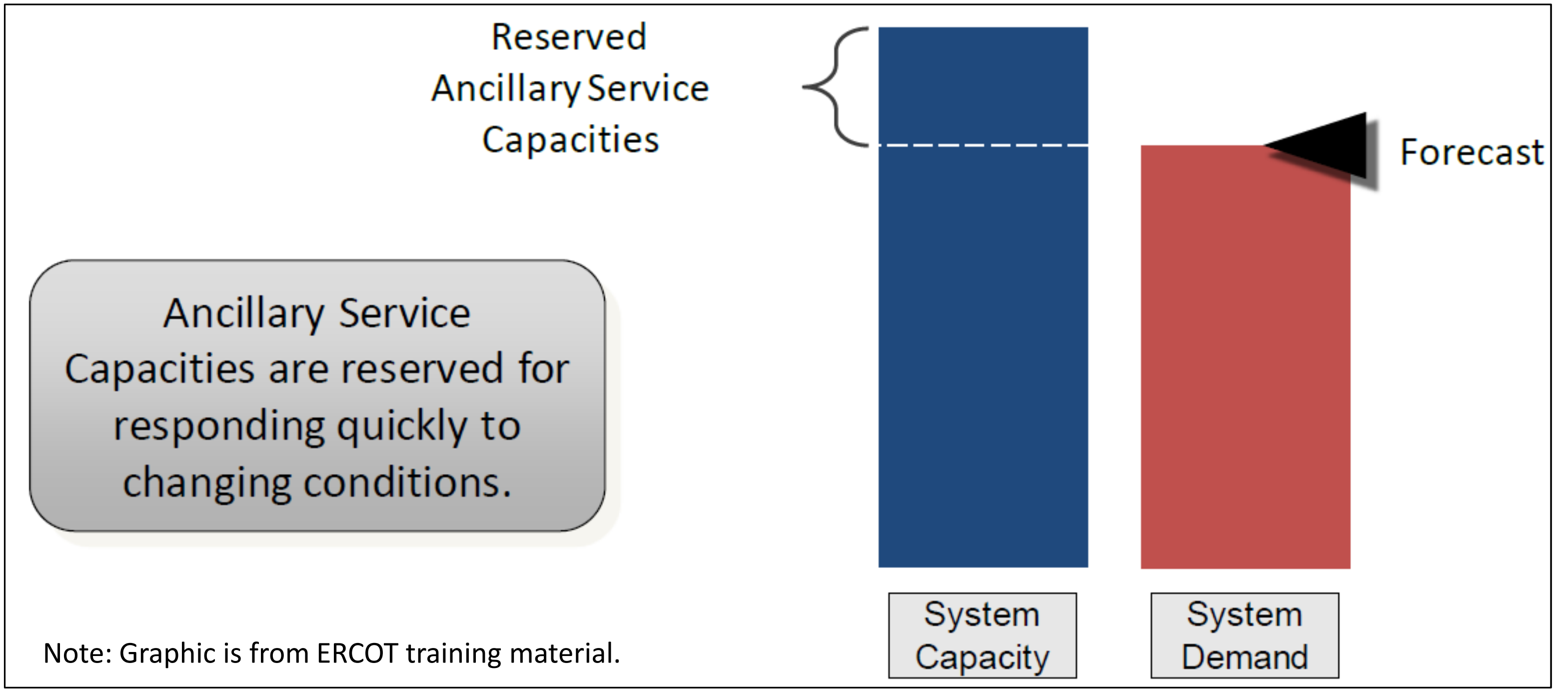
UTIILIZATION – KEY FACTORS

- Energy Utilization
  - Energy utilization was presented to the RAC at Jan 2022 meeting
  - Competitive wholesale market prices determine power plant energy utilization
    - Generally, generators bid variable costs (fuel[1] & variable O&M)
  - Market prices vary by hour, day, night, & season
  - Generation units are primarily dispatched (started and run) based on variable cost
    - The least expensive plants run the most, minimizing cost to customers
  - To "manually" increase utilization would result in higher cost to customers
- Ancillary Service Utilization
  - Generation resources are needed for "capacity" for responding quickly to changing conditions, i.e. the units usually do not run
- Energy + Ancillary Service = Total Utilization

[1] Fuel cost is a function of fuel price & plant fuel efficiency

ANCILLARY SERVICES

- Capacity used by ERCOT to maintain grid reliability minute-by-minute, 365 days per year

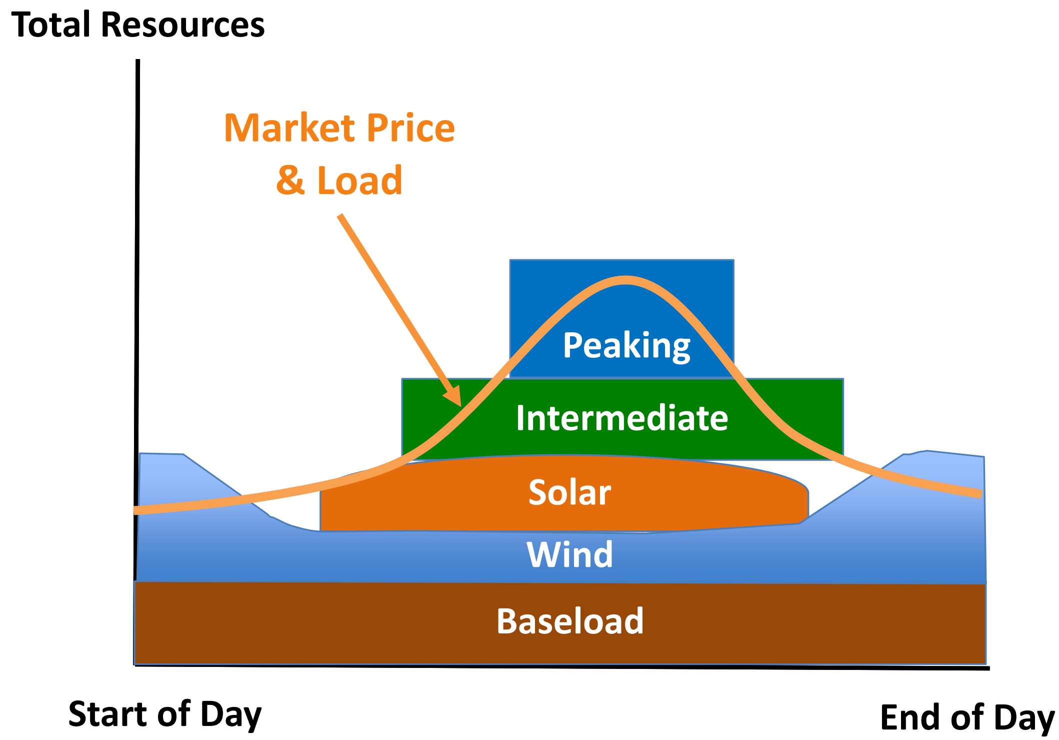


Note: Graphic is from ERCOT training material.

Ancillary services create a financial obligation for our customers.

GENERATION TYPES

- **Peaking Generation**: To minimize capacity shortages and costs over short periods of time
- **Intermediate Generation**: To balance the resource needs of the system between peak and baseload on a daily basis.
- **Renewable Generation**: To minimize emissions & energy costs over long periods of time
- **Baseload Generation**: To minimize fuel & energy costs over long periods of time



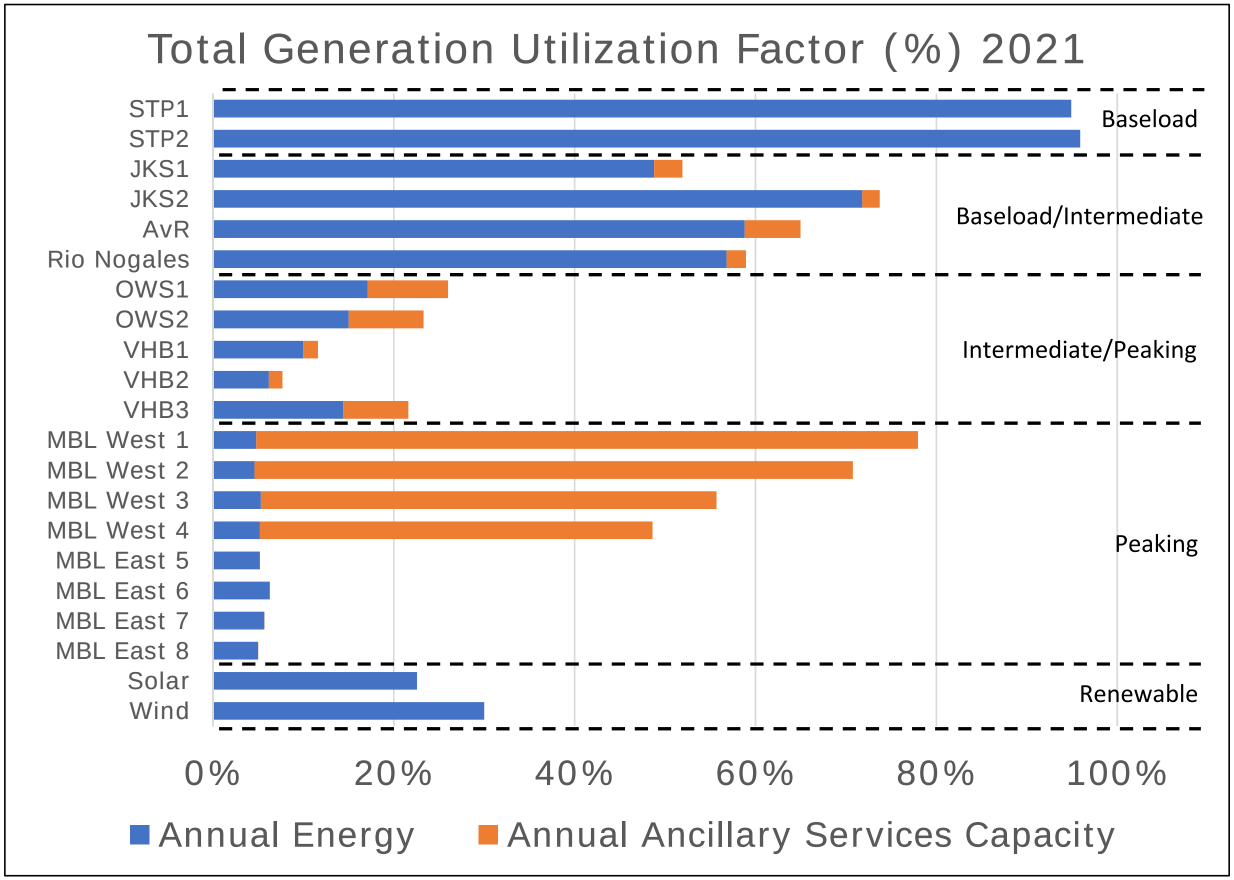
A array of generation types, that balance cost & performance, is used to reliably meet customer demand.

UTILIZATION BY GENERATION TYPE

Generation Type	Utilization	
	Energy	Ancillary Services
Peaking	5% to 25%	Frequently used
Intermediate	25% to 75%	Frequently used
Renewable (Solar & Wind)	25% to 45%	Not used due to intermittent output
Baseload	75% to 100%	Can be limited (resource dependent)

Generation resources are constantly optimized considering many variables.

TOTAL GENERATION UTILIZATION 2021



<u>Total Generation Utilization Factor</u>: Percentage of total capacity used for energy and ancillary services

Adding Energy & Ancillary Services provides the total utilization picture.

KEY TAKEAWAYS

- Our generation planning strategy is to provide sufficient capacity to protect our customers from exposure to high market prices.
- A diverse mix of generating capacity is needed, even if utilization may be low for certain resources
- Utilizing capacity for ancillary services is vital to the reliability of CPS Energy supply and the ERCOT grid
- Energy & ancillary services are a financial obligation for our customers
- Reserve margin helps protect against market exposure

Questions?

APPENDIX

RESOURCE NAME & TYPE

CONVENTIONAL TECHNOLOGIES

Resource Name	Short Name	Capacity (MW)	Type/Fuel
SOUTH TEXAS 1	STP1	517	Baseload/Nuclear
SOUTH TEXAS 2	STP2	512	Baseload/Nuclear
J K SPRUCE 1	JKS1	560	Baseload/Intermediate/Coal
J K SPRUCE 2	JKS2	785	Baseload/Intermediate/Coal
A VON ROSENBERG 1	AvR	518	Baseload/Intermediate/Gas Combined Cycle (CC)/Gas
RIO NOGALES	Rio Nogales	777	Baseload/Intermediate/Gas Combined Cycle (CC)/Gas
O W SOMMERS 1	OWS1	420	Intermediate/Peaking/Gas Steam
O W SOMMERS 2	OWS2	410	Intermediate/Peaking/Gas Steam
V H BRAUNIG 1	VHB1	217	Intermediate/Peaking/Gas Steam
V H BRAUNIG 2	VHB2	230	Intermediate/Peaking/Gas Steam
V H BRAUNIG 3	VHB3	412	Intermediate/Peaking/Gas Steam
MILTON LEE PEAKING 5	MBL East 5	48	Peaking/Gas Combustion Turbine (CT)/Gas
MILTON LEE PEAKING 6	MBL East 6	48	Peaking/Gas Combustion Turbine (CT)/Gas
MILTON LEE PEAKING 7	MBL East 7	48	Peaking/Gas Combustion Turbine (CT)/Gas
MILTON LEE PEAKING 8	MBL East 8	47	Peaking/Gas Combustion Turbine (CT)/Gas
MILTON LEE PEAKING 1	MBL West 1	46	Peaking/Gas Combustion Turbine (CT)/Gas
MILTON LEE PEAKING 2	MBL West 2	46	Peaking/Gas Combustion Turbine (CT)/Gas
MILTON LEE PEAKING 3	MBL West 3	46	Peaking/Gas Combustion Turbine (CT)/Gas
MILTON LEE PEAKING 4	MBL West 4	46	Peaking/Gas Combustion Turbine (CT)/Gas
	Total	5,733	

RESOURCE NAME & TYPE

RENEWABLE TECHNOLOGIES

Resource Name	Capacity Maximum Capability (MW)	Capacity at Summer Peak (MW)	Type
Desert Sky Wind Farm	63.4	12.7	Wind
Cottonwood Creek Wind Farm	82.6	16.5	Wind
Sweetwater 4	240.8	48.2	Wind
Penascal	76.8	43.8	Wind
Papalote Creek	130.4	74.3	Wind
Cedro Hill	150.0	30	Wind
Los Vientos	200.1	114.1	Wind
Blue Wing	13.9	7	Solar
Sinkin 1	9.9	5	Solar
Sinkin 2	9.9	5	Solar
Somerset	10.6	5.3	Solar
CEC_Beck (Community Solar)	1.0	0.5	Solar
Alamo 1	39.2	19.6	Solar
St. Hedwig (Alamo 2)	4.4	2.2	Solar
Eclipse (Alamo 4)	39.6	19.8	Solar
Walzem (Alamo 3)	5.5	2.8	Solar
Helios (Alamo 5)	95.0	47.5	Solar
Solara (Alamo 7)	106.4	53.2	Solar
Sirius 1 (Alamo 6)	110.2	55.1	Solar
Sirius 2 (Pearl)	50.0	25	Solar
Lamesa 2 (Ivory)	50.0	25	Solar
Commerce PV	5.0	2.5	Solar
Commerce BESS	10.0	10.0	Storage
Covel Gardens	9.6	7.3	Landfill Gas
Nelson Gardens	4.2	3.2	Landfill Gas

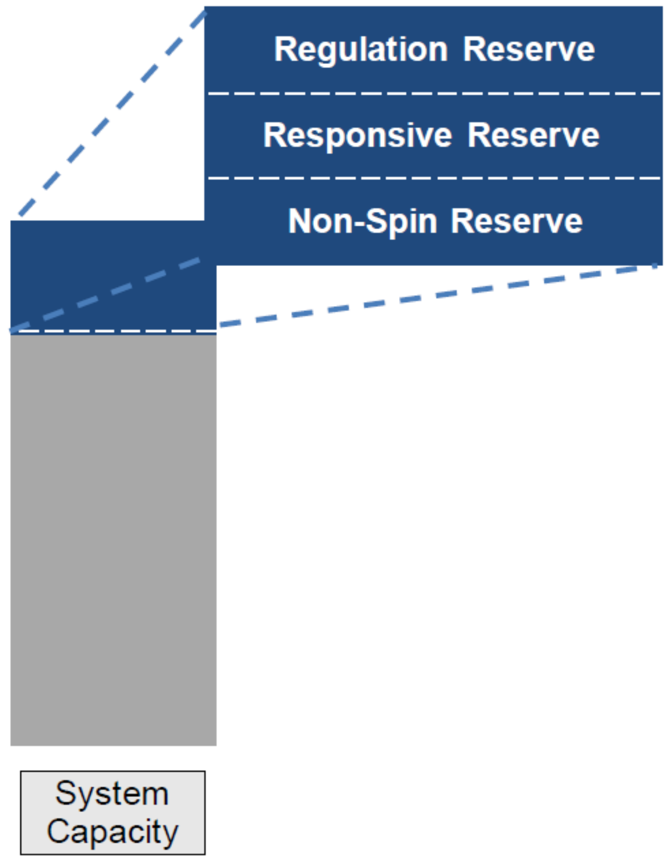
Type	Summer Peak Contribution (% of Max. Capacity)
Nuclear, Coal, Gas, & Storage	100%
West Wind	20%
Coastal Wind	57%
Solar	50%
Landfill Gas	76%

Type	Total (MW)	Total Summer (MW)
Wind	944.1	339.6
Solar	550.6	275.5
Storage	10.0	10.0
Landfill Gas	13.8	10.5
	1519	635.6

ANCILLARY SERVICE TYPES

Ancillary Service Capacity

- Three types of Ancillary Service Capacities
- Different purposes and response times



Note: Graphic is from ERCOT training material.

ANCILLARY SERVICE DEFINITIONS

Ancillary Service Type	Definition
Regulation Down Service	An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency.
Regulation Up Service	An Ancillary Service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes in system frequency.
Responsive Reserve Service	An Ancillary Service that provides operating reserves that is intended to: (a) Arrest frequency decay within the first few seconds of a significant frequency deviation; (b) After the first few seconds of a significant frequency deviation, help restore frequency to its scheduled value to return the system to normal; (c) Provide energy or continued load interruption during the implementation of the Energy Emergency Alert (EEA); and (d) Provide backup regulation.
Non-Spinning Reserve	An Ancillary Service that can be synchronized and ramped to a specified output level within 30 minutes and that can operate at a specified output level for at least one hour.

ENERGY UTILIZATION 2021
MONTHLY

Capacity Factor (%) = Actual Generation / Maximum Generation Capability

	2021	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Baseload	STP1	100	94	100	100	100	89	100	100	100	27	82	100
	STP2	100	100	66	36	100	100	100	100	100	100	100	100
Baseload/ Intermediate	JKS1	60	47	46	17	65	78	72	73	59	37	0	31
	JKS2	62	76	45	74	74	86	78	49	81	89	84	64
	AvR	15	43	75	61	70	75	76	82	48	39	68	55
	Rio Nogales	66	58	22	68	60	80	87	95	93	0	1	54
Intermediate /Peaking	OWS1	7	22	0	24	2	18	32	34	30	34	3	0
	OWS2	4	24	0	9	0	20	28	28	25	30	14	0
	VHB1	0	25	0	5	2	10	13	27	16	16	6	0
	VHB2	0	16	0	5	2	13	22	9	4	6	0	0
	VHB3	8	0	0	0	3	19	30	33	29	37	14	0
Peaking	MBL West 1	8	22	1	6	2	7	6	2	1	3	1	0
	MBL West 2	7	22	1	6	2	6	6	2	1	2	0	0
	MBL West 3	7	23	0	7	3	10	7	2	1	3	1	1
	MBL West 4	4	23	1	8	3	11	8	2	1	2	1	1
	MBL East 5	4	12	4	4	5	12	12	3	2	2	1	2
	MBL East 6	3	29	4	4	7	12	9	3	2	2	2	2
	MBL East 7	3	25	3	3	5	9	10	4	2	2	2	1
	MBL East 8	3	26	3	3	3	9	8	4	2	1	0	0
Renewable	Solar	18	14	23	20	25	29	28	27	26	22	19	16
	Wind	30	26	44	38	39	25	21	26	22	30	29	28

Utilization - Percentage of each month the resource generated power based on the maximum capability of each resource. Resource availability and Demand affect utilization.

ANCILLARY UTILIZATION 2021

MONTHLY

AS Utilization (%) = Capacity Reserved / Maximum Generation Capability

	2021	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Baseload	STP1	0	0	0	0	0	0	0	0	0	0	0	0
	STP2	0	0	0	0	0	0	0	0	0	0	0	0
Baseload/ Intermediate	JKS1	4	2	11	2	9	5	2	0	1	0	0	0
	JKS2	0	4	5	7	4	1	1	0	0	0	1	0
	AvR	1	4	14	8	11	15	5	1	1	2	6	6
	Rio Nogales	4	5	2	2	5	7	0	0	0	0	0	0
Intermediate /Peaking	OWS1	1	8	0	13	2	3	11	21	25	21	1	0
	OWS2	0	1	0	1	0	3	20	20	22	23	9	0
	VHB1	0	9	0	0	0	0	1	1	3	3	2	0
	VHB2	0	2	0	0	0	2	3	2	3	7	0	0
	VHB3	1	0	0	0	0	4	12	14	16	28	10	0
Peaking	MBL West 1	5	12	79	88	88	81	92	94	94	67	92	83
	MBL West 2	1	12	66	77	75	77	86	94	94	44	84	80
	MBL West 3	2	10	31	16	21	26	60	95	95	88	86	71
	MBL West 4	0	0	15	3	6	5	57	94	96	89	84	67
	MBL East 5	0	0	0	0	0	0	0	0	0	0	0	0
	MBL East 6	0	0	0	0	0	0	0	0	0	0	0	0
	MBL East 7	0	0	0	0	0	0	0	0	0	0	0	0
	MBL East 8	0	0	0	0	0	0	0	0	0	0	0	0
Renewable	Solar	0	0	0	0	0	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	0	0	0	0	0	0

Utilization - Percentage of each month the resource capacity that was reserved for Ancillary Services.

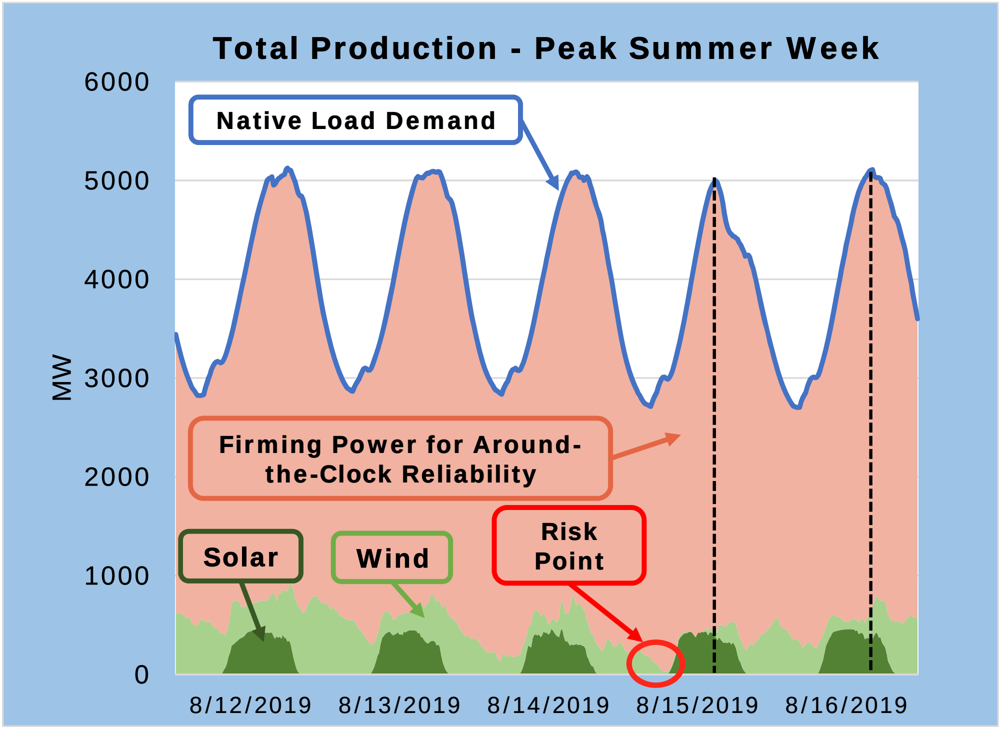
TOTAL UTILIZATION 2021
MONTHLY

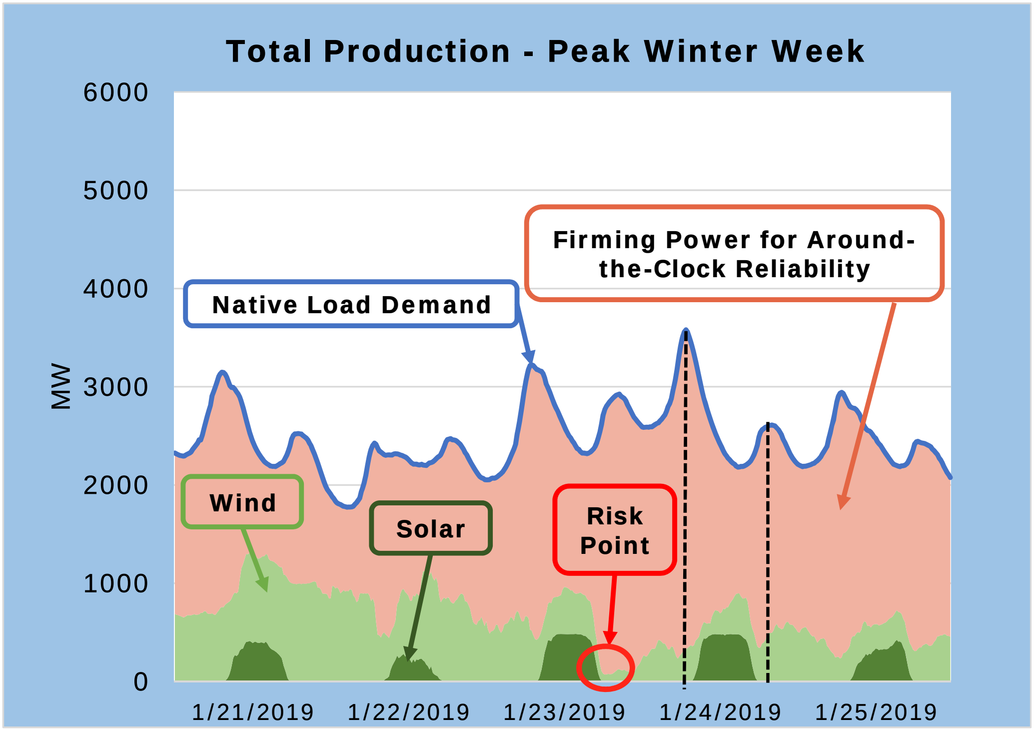
Total Utilization (%) = Capacity Utilized / Maximum Generation Capability

	2021	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Baseload	STP1	100	94	100	100	100	89	100	100	100	27	82	100
	STP2	100	100	66	36	100	100	100	100	100	100	100	100
Baseload/ Intermediate	JKS1	63	50	57	19	74	82	74	73	60	37	0	31
	JKS2	63	79	49	81	78	87	79	49	82	89	85	65
	AvR	16	47	89	69	81	89	81	83	49	41	74	61
	Rio Nogales	70	63	24	70	65	88	87	95	93	0	1	54
Intermediate /Peaking	OWS1	8	31	0	37	4	21	43	55	55	55	4	0
	OWS2	4	25	0	11	0	23	48	47	47	53	23	0
	VHB1	0	34	0	5	2	10	15	29	19	20	8	0
	VHB2	0	18	0	5	2	14	25	10	7	13	0	0
	VHB3	9	0	0	0	3	23	42	47	45	65	24	0
Peaking	MBL West 1	13	34	79	95	90	87	97	96	95	70	93	83
	MBL West 2	8	34	67	83	77	83	92	96	95	47	84	81
	MBL West 3	9	34	32	22	24	37	68	96	97	91	87	72
	MBL West 4	4	23	17	12	9	16	65	96	97	90	85	68
	MBL East 5	4	12	4	4	5	12	12	3	2	2	1	2
	MBL East 6	3	29	4	4	7	12	9	3	2	2	2	2
	MBL East 7	3	25	3	3	5	9	10	4	2	2	2	1
	MBL East 8	3	26	3	3	3	9	8	4	2	1	0	0
Renewable	Solar	18	14	23	20	25	29	28	27	26	22	19	16
	Wind	30	26	44	38	39	25	21	26	22	30	29	28

Total Utilization - Percentage of each month the resource capacity that was used for Energy or Ancillary Services.

PEAK DAYS FOR SAN ANTONIO
IMPORTANCE OF DIVERSITY & RESERVES





Note: CPS Energy wind and solar production data is in 15-minute intervals.

The intermittent nature of solar and wind production shows the need for diversity & reserves to provide around-the-clock reliability.

MODELING, ASSUMPTIONS & SCENARIOS

Presented by:

John Kosub
Senior Director, Energy Supply & Market Operations

Kevin Pollo
VP, Energy Supply & Market Operations

June 16, 2022

Informational Update

AGENDA

- INPUTS & ASSUMPTIONS INTRODUCTION
- SERVICE TERRITORY
- ELECTRIC LOAD FORECAST
- GENERATION PERFORMANCE
- PORTFOLIO OPTIONS

INPUTS & ASSUMPTIONS INTRODUCTION

PROPOSED MODELING PROCESS

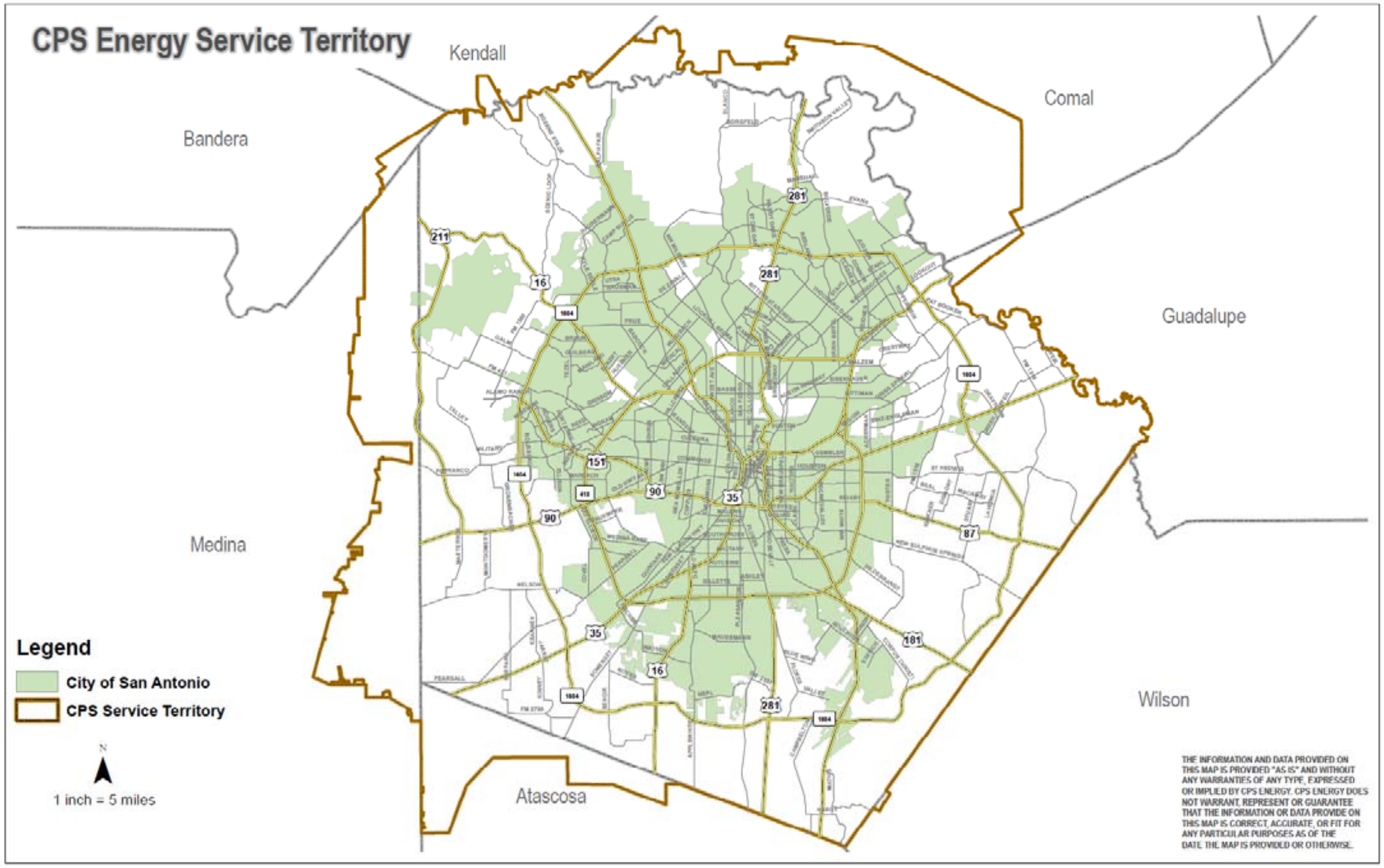
- Assumptions
  - Customer usage, Energy Efficiency, Generation cost and performance, generation additions, generation retirement schedule, fuel prices, market prices, financial assumptions, etc.
- Modeling
  - Each portfolio to be run through our production cost model over a 25-year forecast horizon and compared to a baseline portfolio
  - Uncertainty analysis included
  - Favorable projects to be run through our financial model to assess financial metrics and bill impact
- Points of Consideration
  - Affordability
  - Reliability/Resiliency
  - Environmental Responsibility
  - Workforce Impacts
  - Risk

SERVICE TERRITORY

CPS ENERGY SERVICE TERRITORY

CPS Energy Service Territory is within the San Antonio Metropolitan Statistical Area.

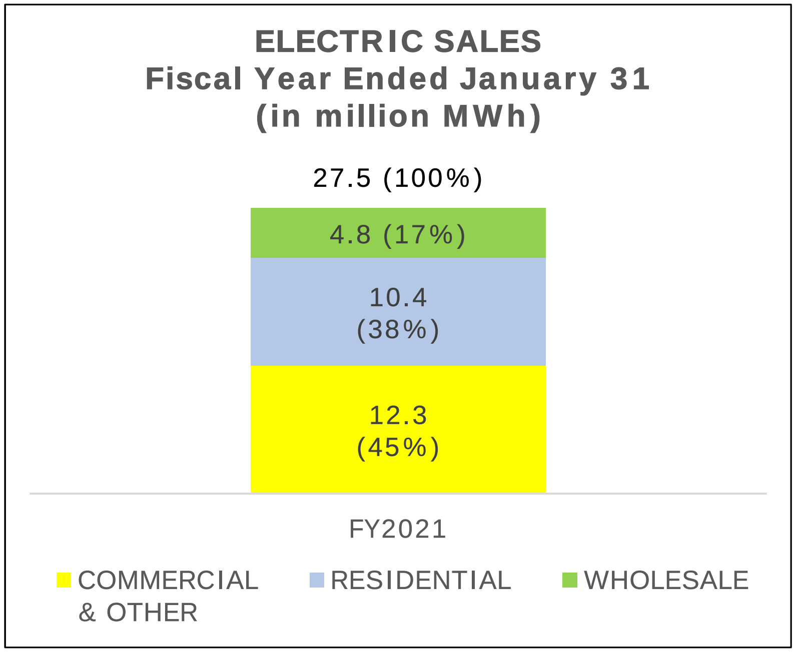
- The majority of CPS Energy service territory is aligned with Bexar County.
- It includes portions of in the surrounding counties of Atascosa, Bandera, Comal, Guadalupe, Kendall, Medina, & Wilson.



ELECTRIC LOAD FORECAST

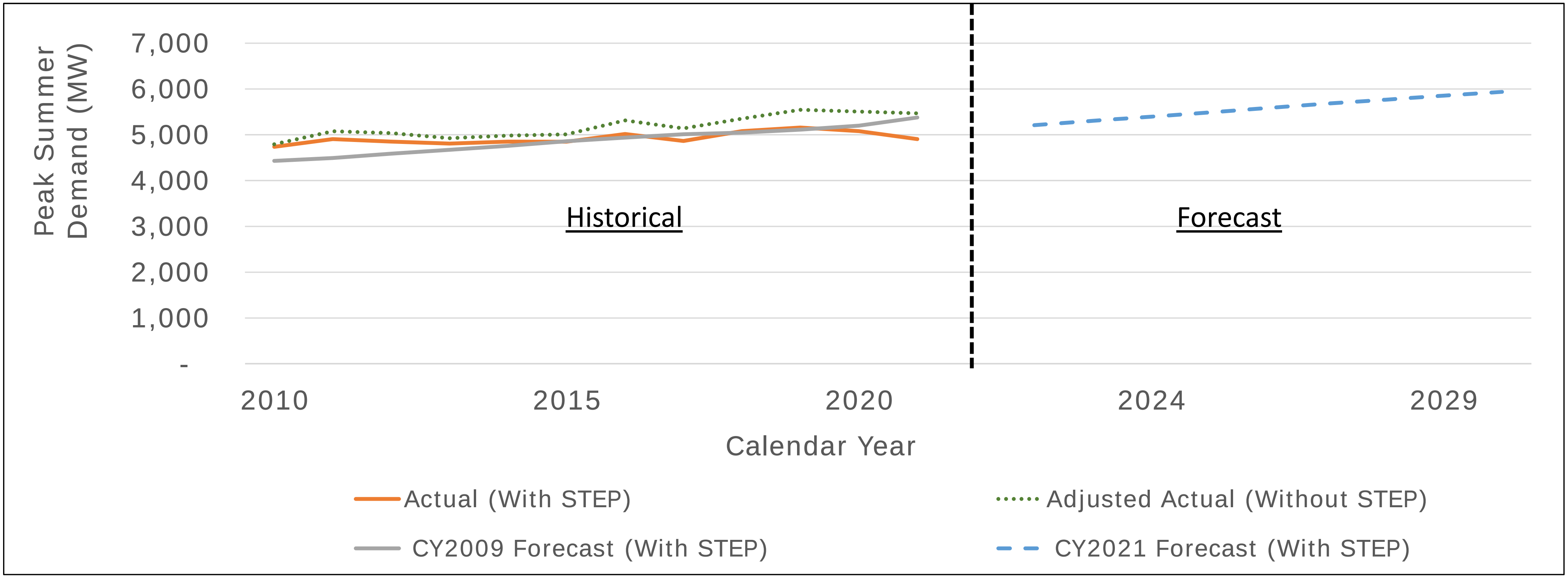
LOAD FORECAST
PURPOSE

- Forecast electric retail sales (MWh) for revenue planning
- Forecast peak demand (MW) for power generation long-range capacity planning
- 25-year, hourly forecast using regression model
- Industry leading model with expert technical & analytical support



We install generation capacity to meet our community's obligations. Any excess generation is offered to the ERCOT wholesale market.

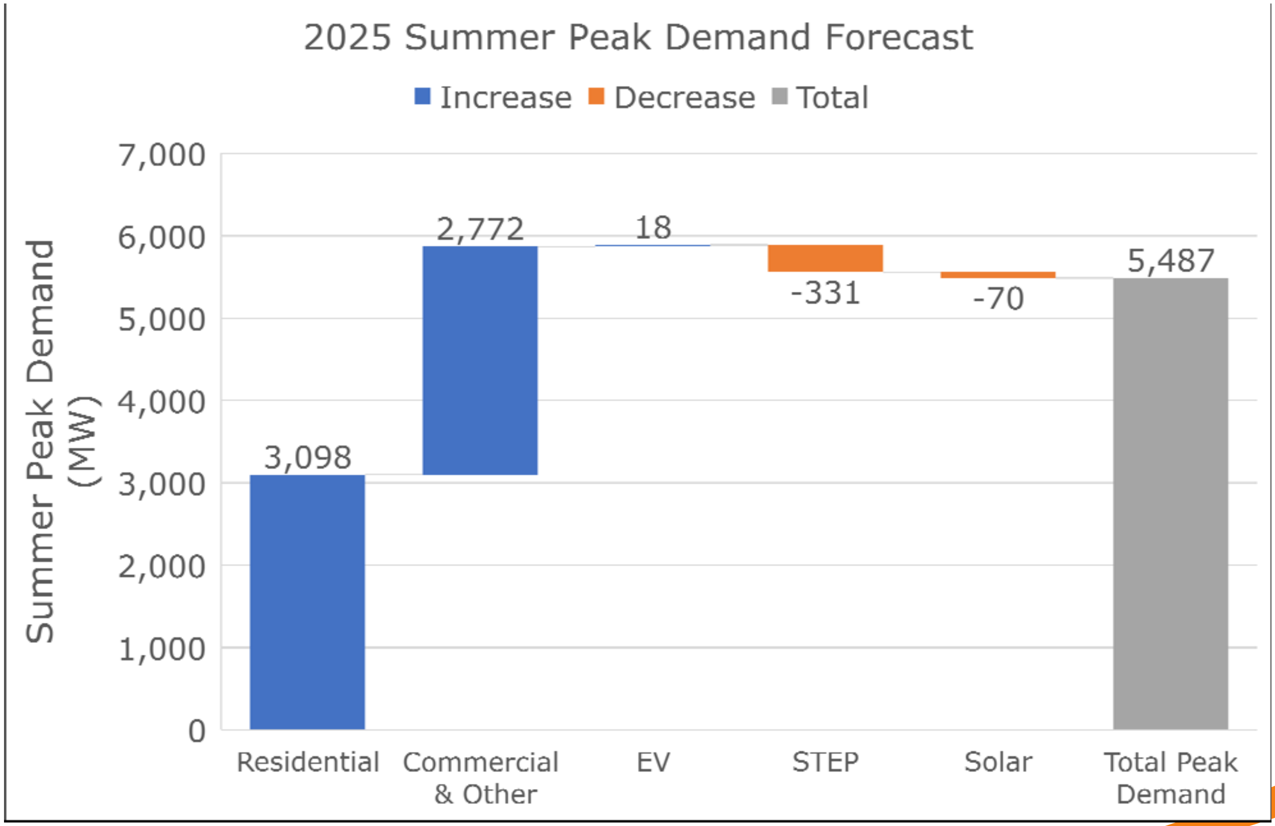
PEAK DEMAND (MW)
TRENDS



Historical summer peak demand has been trending near the forecast. About 95 MW per year of customer growth is expected in the forecast.

PEAK DEMAND (MW)
KEY FORECAST INPUTS

- Key inputs: Differing customer classes, Electric Vehicles (EV), STEP, and Rooftop Solar
- Hourly forecast captures seasonal and time of day patterns
- Captures summer & winter peak capacity (MW) needs
- Uncertainty in peak capacity (MW) forecast is covered with reserve margin



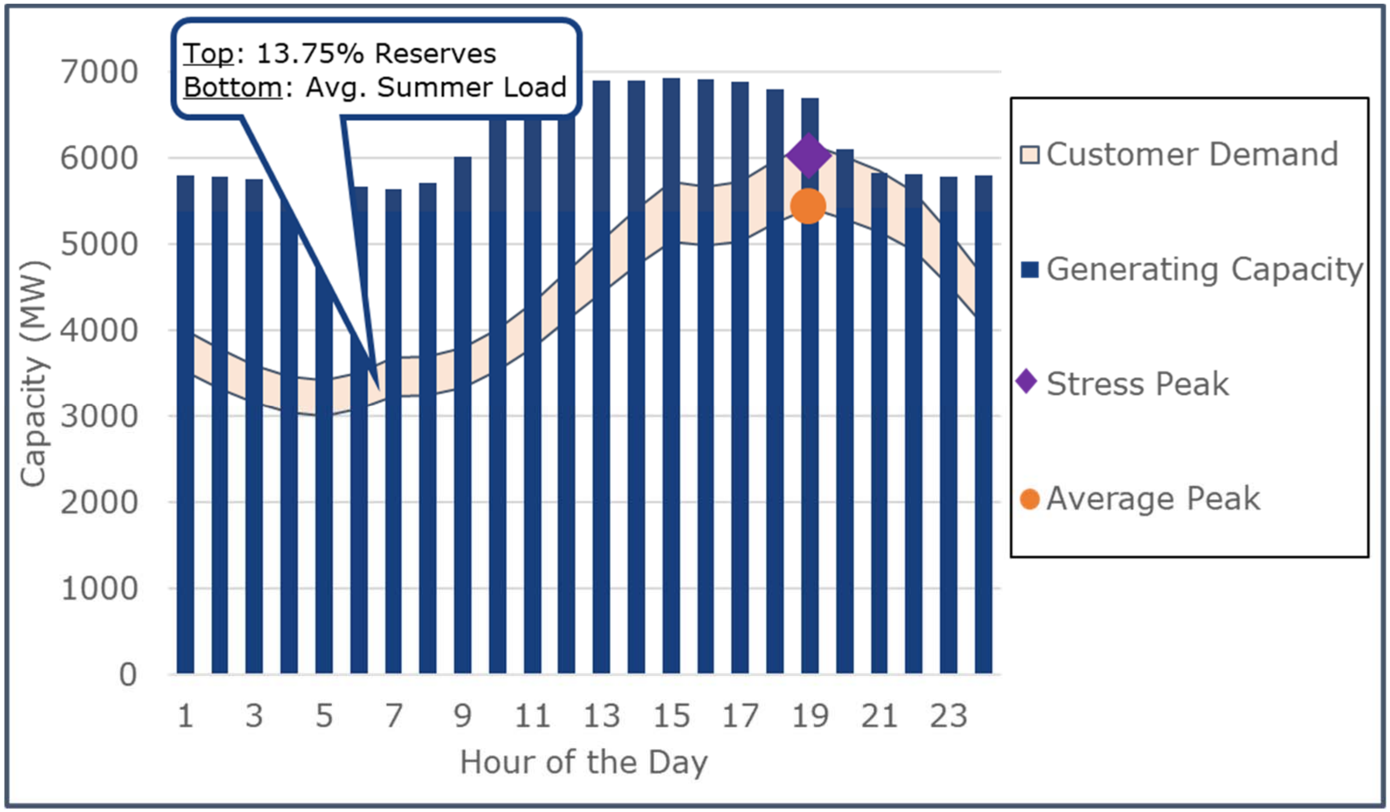
WEATHER

	Typical Weather	Extreme Weather
Deg F	Average 15 years	Max/Min 30+ years (1990+)
Month	Temperature	Temperature
January	32	17
February	30	9
March	81	21
April	93	99
May	98	103
June	100	107
July	100	106
August	102	109
September	98	111
October	94	99
November	89	89
December	30	16

- The forecast captures climate change trends using 15 years of historical data
- We track extreme weather trends & ensure our planned reserve margin can cover extremes

When evaluating system peak capacity needs, we consider differing weather conditions: Typical Weather and Extreme Weather.

SUMMER DAY
2025 PROJECTION – DEMAND & SUPPLY



2025 Summer Forecast:

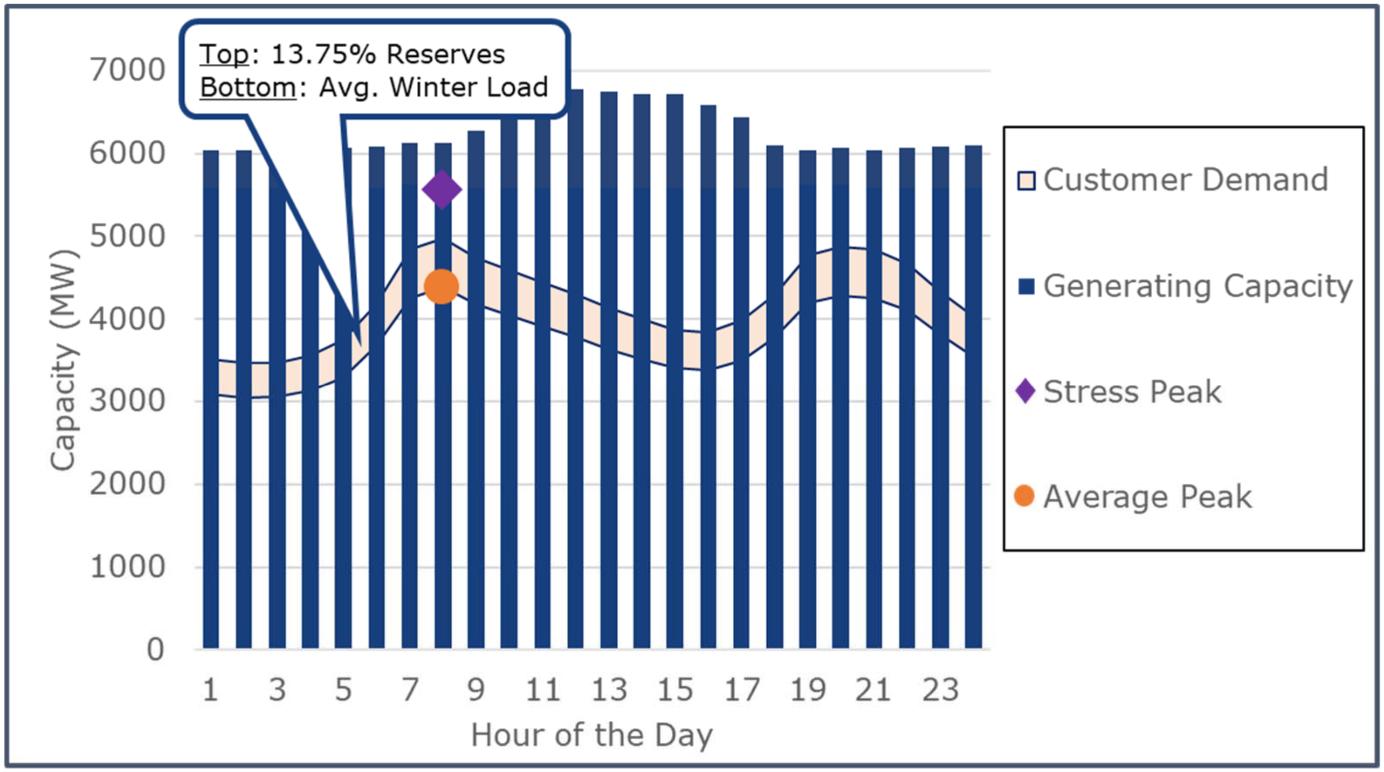
Demand:
- **Avg. Peak: 5,487 MW**
- **Stress Peak: 6,028 MW**

Supply:
- **Nuclear, Coal, Gas, & Storage: 100%**
- **Coastal Wind: 57%**
- **West Wind: 20%**
- **Solar: 50%**

Note: Updated to CY2021 forecast

All resources are utilized to meet summer peak demand.

WINTER DAY
2025 PROJECTION – DEMAND & SUPPLY



2025 Winter Forecast:

Demand:
- Avg. Peak: 4,379MW
- Stress Peak: 5,555MW

Supply:
- Nuclear, Coal, Gas, & Storage: 100%
- Coastal Wind: 43%
- West Wind: 19%
- Solar: 0.9%

Note: Updated to CY2021 forecast

All resources are utilized to meet extreme winter peak demand while average winter peak is less challenging.

ELECTRIC VEHICLES

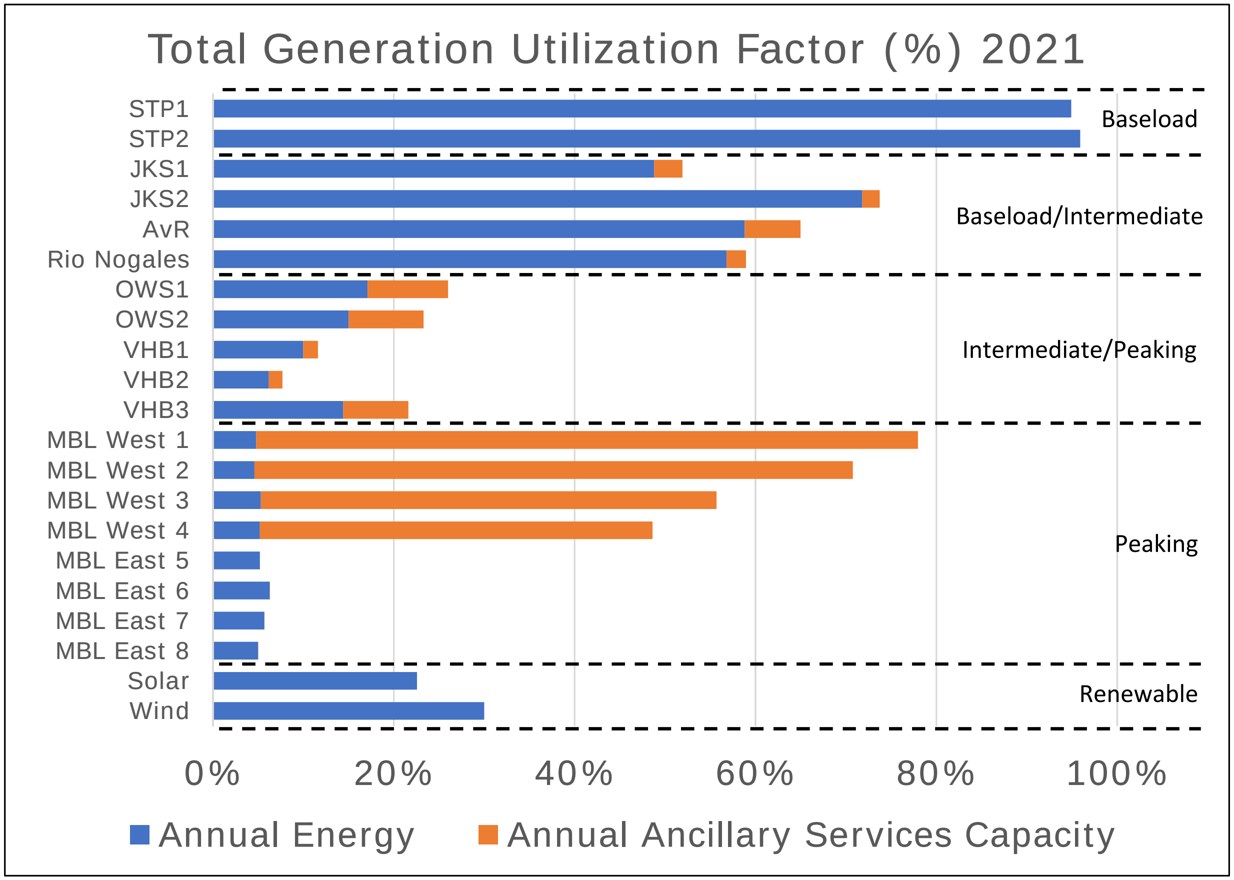
- Although EVs are currently a relatively small segment of the forecast, we are closely monitoring the growth rate
- EV forecast inputs:
  - Light Duty EV growth[1]
    - At home Time of Use (TOU) and non-TOU charging profiles
    - Workplace & public charging
  - Mid & Heavy EV growth
    - Some quantifiable growth per known commercial customers plans
    - More to be coming soon[2]: Trucks, Busses, other

Electric Vehicle (EV) adoption is captured in our forecast process.

1. Supplied by Electric Power Research Institute (EPRI)
2. Internally estimated from Alamo Area Council of Governments (AACOG) data & International Council of Clean Transportation data

GENERATION PERFORMANCE

TOTAL GENERATION UTILIZATION 2021

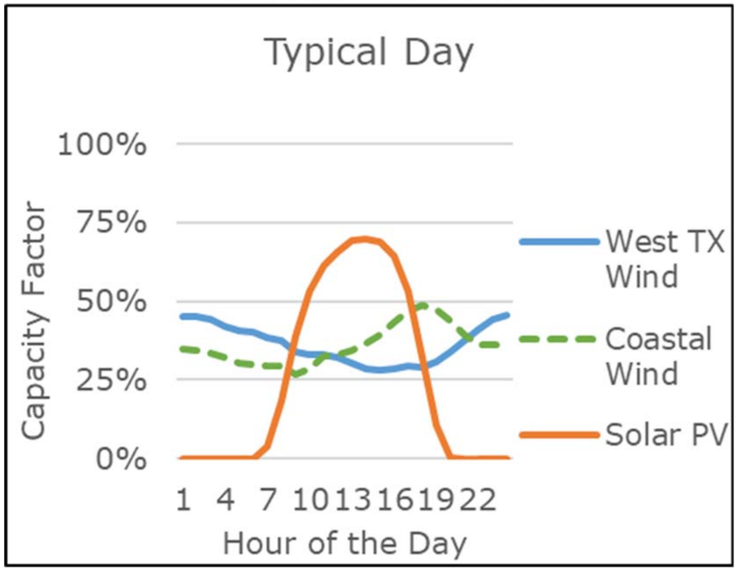


<u>Total Generation Utilization Factor</u>: Percentage of total capacity used for energy and ancillary services

Adding Energy & Ancillary Services provides the total utilization picture.

RENEWABLE GENERATION
EMERGING OPPORTUNITIES

Solar & Wind



Type	Summer Peak Contribution (% of Max. Capacity)
Nuclear, Coal, Gas, & Storage	100%
West Wind	20%
Coastal Wind	57%
Solar	50%
Landfill Gas	76%

Type	Total (MW)	Total Summer (MW)
Wind	944.1	339.6
Solar	550.6	275.5
Storage	10.0	10.0
Landfill Gas	13.8	10.5
	1519	635.6

- Average peak contribution percentages used for long-range planning.
- Daily weather forecasts used for next-day wind and solar generation predictions.
- Real-time weather conditions determine actual generation available

Our long-term and short-term planning processes incorporate the unique operating profiles for renewable resources.

PORTFOLIO OPTIONS

PORTFOLIO MODELING*
POTENTIAL RETIREMENT DATES

Unit	MW	2022	2023	2024	2025	2026	2027	2028	2029	2030
South Texas 1	517									
South Texas 2	512									
Spruce 1	560									
Spruce 2	785									
Arthur Von Rosenberg	518									
Rio Nogales	777									
Sommers 1	420									
Sommers 2	410									
Braunig 1	217									
Braunig 2	230									
Braunig 3	412									
Milton Lee Peaking 1-8	376									

* Possible Spruce 2 gas conversion & all retirement dates are preliminary & for discussion purposes only.

Over 3,000 MWs of new generation will be required to meet customer needs by 2030.

PORTFOLIO MODELING*
PROPOSED STARTING POINT

Possible Retirements:
- o Braunig 1: Mar 2025
- o Braunig 2: Mar 2025
- o Braunig 3: Mar 2025
- o Sommers 1: Mar 2027
- o Spruce 1: Dec 2028
- o Sommers 2: Mar 2029

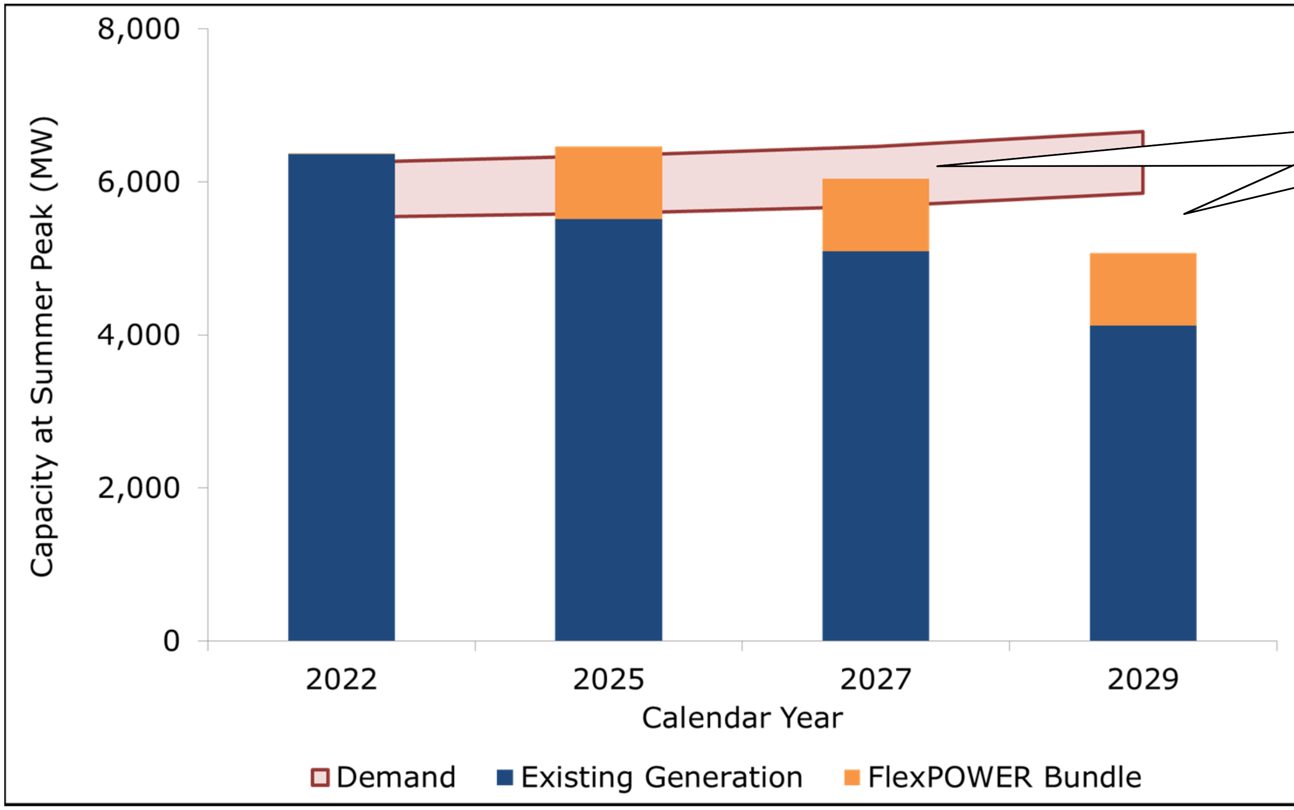
Planned Additions:
- o Solar: 2024 to 2025
- o Storage: 2024
- o Firming: 2022
- o Sommers 1 replacement
- o Spruce 1 replacement
- o Sommers 2 replacement
- o Load growth capacity

Other:
- o Possible conversion of Spruce 2 from coal to gas: Dec 2027
- o Potential inclusion of Geothermal, Geo-mechanical Pumped Storage

* Possible Spruce 2 gas conversion & all retirement dates are preliminary & for discussion purposes only.
* Our power generation plan update will define the resource types to use for the additions highlighted in grey.

We will work with RAC, CAC, & the community for feedback to model the scenarios and bring back the recommendations to the Board by December.

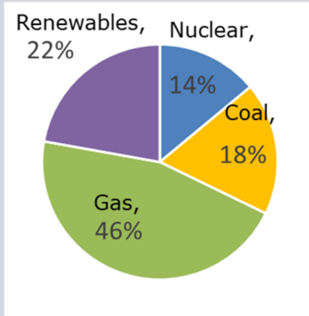
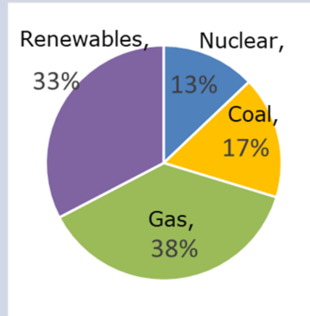
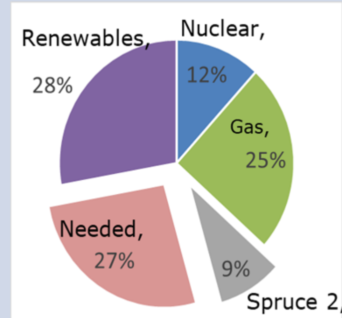
CAPACITY PLANNING
WE MUST CAREFULLY COVER S.A.'S NEEDS



Planning is underway to fill capacity gaps.

Our generation planning strategy is to provide sufficient capacity to protect our customers from exposure to high market prices.

POWER GENERATION PORTFOLIO
POTENTIAL FUTURE LOOK

	2021	2025	2030
			
Nameplate Capacity:	7,350 MW	8,050 MW	TBD
Capacity at Peak:	6,377 MW	6,833 MW	TBD
Demand:	5,159 MW	5,487 MW	5,937 MW
	Current view	Key assumptions: • Add 900 MW of solar • Add 50 MW of battery storage • Add 500 MW of gas-fired firming capacity • Retire three Braunig gas steam units	Key assumptions: • Retire Sommers 1 • Retire Sommers 2 • Retire Spruce 1 • Retire or convert Spruce 2 Additional capacity needed to meet obligations

Our generation planning process will identify the types of resources to be added over the next several years.

PORTFOLIO MODELING
PROPOSED PORTFOLIO OPTIONS

Portfolio	Aspects
Renewable	• Wind, solar, & other • Storage
Natural Gas	• Combined cycle • Reciprocating internal combustion engine
Blended	• Economic maximum renewables: Wind, solar, & other • Economic storage • Natural Gas: Combined cycle & Reciprocating internal combustion engine

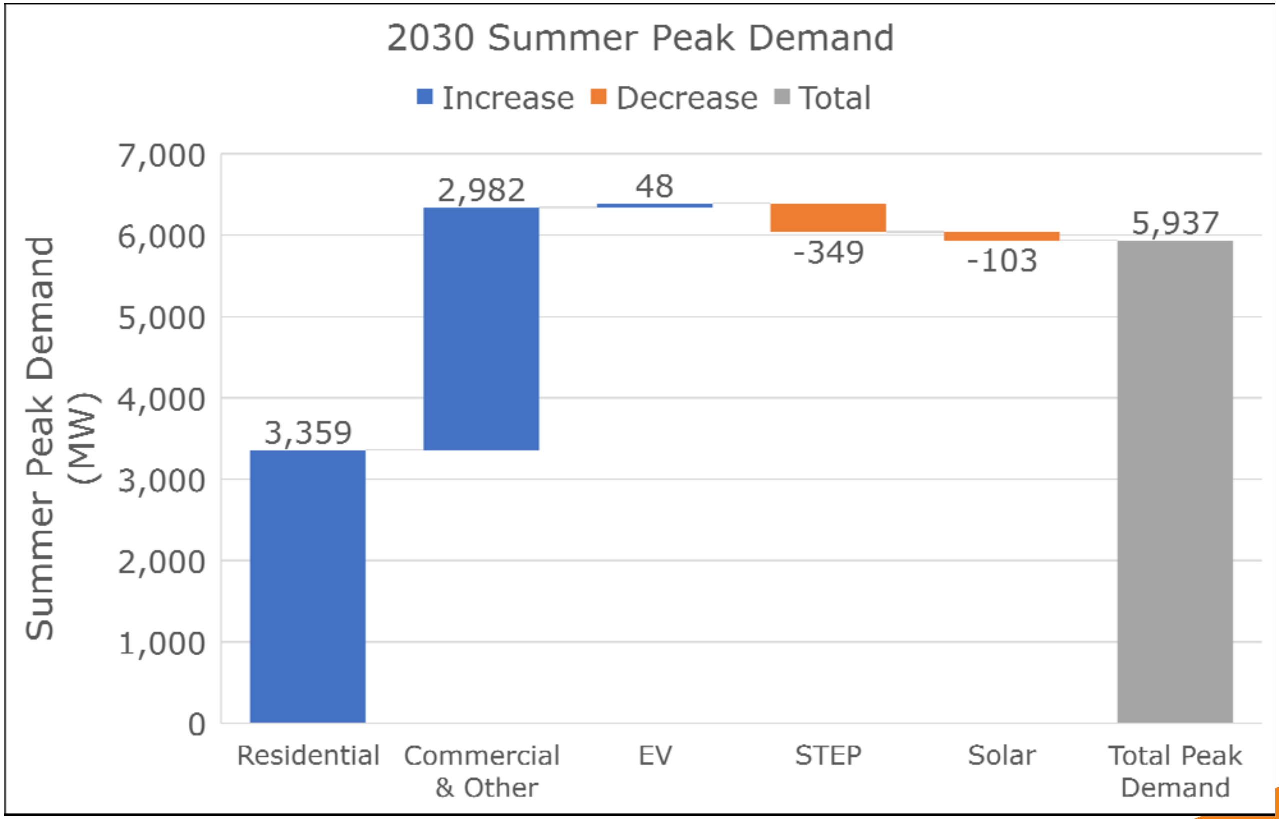
Notes:
1. Spruce 2 converted to gas in all of the above portfolios
2. Each portfolio assessed with and without "Save Now".
3. Emerging technology assumptions to be included.

Capacity is needed to address customer growth and unit retirements (Sommers 1 & 2, Spruce 1).

APPENDIX

PEAK DEMAND (MW)
KEY FORECAST INPUTS

- Key inputs: Differing customer classes, Electric Vehicles (EV), STEP, and Rooftop Solar
- Hourly forecast captures seasonal and time of day patterns
- Captures summer & winter peak capacity (MW) needs
- Uncertainty in peak capacity (MW) forecast is covered with reserve margin



WORKPAPERS

BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION

APPLICATION OF BALTIMORE GAS	**§**	
& ELECTRIC COMPANY TO ADJUST	**§**	**CASE NO. 9610**
ELECTRIC AND GAS BASE RATES	**§**	

DIRECT TESTIMONY

OF

CLARENCE L. JOHNSON

ON BEHALF OF THE

MARYLAND OFFICE OF PEOPLE'S COUNSEL

SEPTEMBER 10, 2019

CASE NO. 9610

DIRECT TESTIMONY OF CLARENCE JOHNSON

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. WHAT IS YOUR OCCUPATION?

A. I am self-employed as a consultant who provides technical analysis and advice regarding energy and utility regulatory issues. I have been retained by the Maryland Office of People's Counsel ("OPC") to testify in this proceeding.

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

A. Yes. I have 35 years of experience as a professional regulatory analyst for the Texas Office of Public Utility Counsel ("OPUC") and as an independent expert witness in proceedings before the Public Utility Commission of Texas, Texas Railroad Commission, Pennsylvania Public Utility Commission, and the Connecticut Department of Public Utilities. I have sponsored testimony in more than 150 regulatory cases.

Q. WHAT WERE YOUR RESPONSIBILITIES AT THE TEXAS OPUC?

A. As OPUC's Director of Regulatory Analysis, I was the professional staff person with the primary responsibility for advising the OPUC on economic and regulatory policy issues. My responsibilities included reviewing utility rate applications, recommending actions or positions to be taken by the Office, preparing and presenting expert testimony, and working with other experts employed or retained by OPUC to coordinate the agency's technical evidentiary positions. I also held supervisory responsibilities with respect to OPUC's technical analysis staff. In addition, my responsibilities included providing technical assistance on legislative matters.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

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

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE MARYLAND PSC?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This testimony will address selected cost allocation and rate design issues in the Baltimore Gas & Electric Co. ("BGE" or "Company") application. In addressing cost allocation and rate design, my testimony will utilize BGE's requested revenue requirement to facilitate ease of comparison. However, this does not in any way indicate acceptance of BGE's request. Mr. Effron will present OPCs proposed reductions to the Company's revenue requirement.

Q. PLEASE SUMMARIZE YOUR TESTIMONY RECOMMENDATIONS.

A. My recommendations and conclusions are summarized below.

- BGE employs large customer account personnel who assist and serve large commercial and industrial customers. The cost of these personnel should be assigned to the commercial and industrial classes in the CCOS studies.

- Information, instructional, and general advertising expense in Accounts 909-910 and 930.1 should be allocated on the basis of revenues.

- BGE incurred AMI meter costs which exceeded the cost of new electro-mechanical meters in order to achieve system and societal benefits. The increment of additional cost over and above the replacement cost of non-AMI meters is not appropriately classified as customer-related. I recommend allocation of this portion of AMI meter cost on the basis of the energy conservation rate base allocator in the electric CCOS study
.

- The Company's call center analysis can be used to identify calls which are appropriately classified as customer-related. Based on this data, 45% of call center costs should be allocated on the basis of the total O&M allocator instead of the customer allocator.

- Accounts 363 (purification), 378 (measurement and regulation), and 379 (city gate measurement and regulation) in the gas CCOS study should be allocated on the basis of total throughput because these functions are not limited to peak hours or peak days. Electricity expense (Account 921) for the gas utility should be allocated on the basis of total throughput and NCP demand, depending on the underlying electric billing.

- The impact of the CCOS study recommendations above informed my recommendations regarding class revenue distribution. For the electric revenue increase, I recommend limiting the residential base revenue increase to 110% of the system average percent increase. For the gas revenue increase, I recommend limiting the residential base revenue increase to 95% of the system average percent increase.

- The customer charge should be limited to basic customer accounts that vary directly with customers. I developed a basic customer charge benchmark for evaluating BGE's residential customer charge. The benchmark customer charges of $5.54 (electric) and $10.85 (gas) shows that the current electric customer charge of $7.90 and gas customer charge of $12.00 exceed direct customer costs and produce margins sufficient to contribute to indirect costs. My recommendation is to maintain the current residential customer charges and reject the Company's proposal to increase the electric and gas customer charges.

- My recommendation is to reject the Company's proposed administrative services adder to Standard Offer Service (SOS).

II. CLASS COST OF SERVICE STUDY

A. Overview

Q. HAS BGE PRESENTED STUDIES TO SUPPORT ITS PROPOSED DISTRIBUTION OF REVENUE REQUIREMENTS AMONG CUSTOMER CLASSES?

A. Yes. BGE presents separate class cost of service studies for its electric and gas costs. My testimony will address those studies.

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

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

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

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

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

The three major steps of the embedded cost of service study are functionalization, classification, and allocation. Functionalization is the procedure for separating costs into functional segments, such as production, transmission, and distribution. The next two accounting steps, classification and allocation, facilitate the recognition of causation. The classification procedure, which pools costs into general categories of causation (i.e., demand, customer, energy) is an intermediate step in determining the allocation factors that are used to divide costs among jurisdictions and customer classes. The development of allocation factors for demand, customer, and energy may involve the selection of specific types of allocation factors for various costs. For example, demand factors may be coincident or non-coincident peak demand, and customer allocation factors may include cost weightings that are applied to ratios of class customer counts. A substantial portion of costs are classified to internal allocation methods (such as labor or O&M expense) which track the study's internal allocations and assignments.

Q. DOES THIS OVERVIEW APPLY TO THE GAS CCOS STUDY AS WELL AS THE ELECTRIC CCOS STUDY?

A. Yes. The CCOS principles are the same for the gas and electric CCOS studies. BGE utilizes the same CCOS template for the both the electric and gas studies. Given the different physical characteristics of gas and electricity, different nomenclature applies to some classification and allocation methods. For instance, BGE uses Peak Day as the measure of coincident peak demand for the gas utility and 4 Coincident Peak hours as the measure of coincident peak for the electric utility.

Q. PLEASE DESCRIBE YOUR REVIEW OF BGE'S CCOS STUDIES.

A. I evaluated the gas and electric CCOS studies for consistency, accuracy, and reasonableness in the allocation of costs among classes. My testimony recommends allocation changes for both the electric and gas CCOS studies. My recommendation focuses on a limited number of CCOS issues; omission of other issues should not be construed as agreement with all other aspects of the Company's study.

B. LARGE CUSTOMER ACCOUNT REPRESENTATIVES

Q. DOES BGE HAVE CUSTOMER ACCOUNT REPRESENTATIVES WHO ASSIST LARGE COMMERCIAL AND LARGE INDUSTRIAL CUSTOMERS?

A. Yes. BGE identified the costs of senior executives, the senior manager of large customer service, and major customer account representatives who assist large industrial/commercial BGE customers.[1] The cost of these employees is $1.453 million for the electric utility and $740 thousand for the gas utility. Because these personnel are dedicated to serving large commercial and industrial customers, my recommendation is to assign these costs only to large commercial and industrial classes. According to the Company, these costs are recorded as Administrative & General (A&G) expenses. These costs are currently allocated primarily on the basis of labor (payroll associated with cost functions), which allocates a large portion of the costs to classes with small or medium size customers, such as residential and general service. Assigning these costs to classes with large customers is consistent with cost causation.

Q. WHY DO UTILITIES EMPLOY ACCOUNT REPRESENTATIVES SPECIFICALLY TO ASSIST LARGE COMMERCIAL AND INDUSTRIAL CUSTOMERS?

A. Industrial accounts tend to be more complex than other accounts and require specialized knowledge and more intensive assistance. Furthermore, given the amount of revenues generated by the accounts, utilities are motivated to provide individualized customer service in order to retain the customers in the service territory. BGE describes the objectives of these personnel: establishing a professional relationship and point of contact with the largest commercial, industrial, and government customers, such as hospitals with life saving equipment and national customers with a presence in the BGE

[1] BGE Response to OPC DR 5-8. (Included as Attachment B to this testimony.)

service area; educate large customers regarding BGE programs and incentives, providing high level assistance regarding rate and supply alternatives; facilitate and coordinate BGE engineering support for customers' equipment restoration, reliability, energy conservation, and billing issues; update and maintain customer specific information; and improve processes that drive customer satisfaction.[2]

Q. HOW DID YOU REALLOCATE THE MAJOR CUSTOMER ACCOUNT REPRESENTATIVE COST?

A. The Company identifies the GL, P, and T classes as the principal electric tariffs applicable to the Large Customer Service group. Therefore, my recommendation is to assign these expenses to those three classes. The expense is allocated among the three classes in proportion to the classes' labor allocation factors. My analysis quantified the class allocation impacts of the direct assignment, and I adjusted the electric CCOS study to reflect the effects on all customer classes.

Q. DID YOU MAKE THE SAME ADJUSTMENT TO THE GAS CCOS STUDY?

A. Yes. The Company identified the IS and C customer classes as the gas utility rate classes that are served by these personnel. I performed the same analysis and adjustment for the gas CCOS study as I described for the electric CCOS study.

C. Informational And Advertising Expense (A909-910 and A930.1)

Q. DO YOU RECOMMEND AN ADJUSTMENT TO THE COMPANY'S ALLOCATION OF EXPENSES FOR ADVERTISING AND OTHER INFORMATIONAL ACTIVITIES?

A. Yes. I propose to allocate information and instructional expense (A909), miscellaneous customer service and information expense (A910), and general advertising (A930.1) on the basis of revenues. The Company allocates A909 – 910 on the basis of class

[2] BGE Response to OPC DR 5-10. (Included as Attachment C to this testimony.)

average number of customers and A930.1 on the basis of labor expense. These costs do not vary with the number of customers, and the allocation factors used by the Company are too narrow to reflect the general institutional objectives of the Company's information dissemination.

Q. PLEASE CLARIFY THE INCLUSION OF A930.1 GENERAL ADVERTISING EXPENSE IN YOUR ALLOCATION ADJUSTMENT.

A. The advertising expense recorded in A930.1 is "of an institutional nature, directed at establishing a favorable image of the utility or its employees."[3] The Company states that BGE's revenue requirement witness sponsors an adjustment to exclude the expense[4]. However, the Company's ECCOS study includes the $648 thousand expense for this advertising in A930.1, which affects the customer class allocation.[5] To the extent that the cost is included in the CCOS study, the allocation method should be more broadly encompassing. Because the advertising is promotional in nature, enhancing the image of BGE, a revenue allocation is more reflective of the intended objective of the expenditure.

Q. PLEASE DISCUSS THE ALLOCATION OF INFORMATIONAL ACTIVITIES IN A909 – 910.

A. The general objective of information activities in these accounts is to encourage the safe and efficient use of the utility's services. A simple customer allocation is exceptionally narrow and limited, allocating approximately 90% of the expense to residential customers. The information dissemination can have promotional aspects,

[3] Id.
[4] Id.
[5] The Company's GCCOS study similarly includes a $333 thousand expense in A930.1.

and the goal of safe and efficient use of electricity and gas should be aimed at providing societal benefits. According to the Company, the informational activities in A910 include: "strategic communications initiatives, marketing, customer service training, corporate communications, and educational outreach."[6] The expenditures in A909 – 910 are broadly promotional of the utilities' services, and assist the community in limiting behavior that could result in electrocution or gas explosions. The benefits accrue to all customer classes and the revenue allocator spreads the costs in proportion to class responsibility for all utility costs. Costs which are intended to influence customers' usage decisions do not vary with the number of customers and can be allocated on a revenue basis.[7]

Q. IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF THESE ACCOUNTS APPLICABLE TO BOTH THE ECCOS AND GCCOS STUDIES?

A. Yes.

D. <u>AMI METERS</u>

Q. HOW DOES BGE ALLOCATE AMI METERS?

A. The Company essentially allocates AMI meters to customer classes in proportion to the number of AMI meters serving each class. The allocation is the same approach used to allocate non-AMI meters to customer classes. Although the allocation is weighted for the differences in meter size among customer classes, the results are close to a straight customer allocation.

[6] BGE Response to OPC DR 5-22, Attachment 2. (Included as Attachment D to this testimony.)
[7] National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (CAM) at 104 (1994).

Q. DO YOU AGREE WITH THIS ALLOCATION?

A. Not in all respects. In particular, the allocation method disregards the reason that AMI meters were installed to replace standard electro-mechanical meters, and therefore fails to reflect cost causation. The installation of AMI meters represents a substantial investment cost in order to access meter functions which transcend the standard billing and collection measurement role. The allocation method for AMI meters should take into account the incremental cost of enabling other functions.

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

A. The replacement cost of a manual residential meter is $225, and the cost of a comparable smart meter is $320.[8] Thus, the manual meter is approximately 70% of the cost of the smart meter. The remaining 30% of the smart meter cost represents investment incurred for functions which cannot be performed by a manual meter. The additional functions are associated with potential benefits that can reasonably be termed system benefits or societal benefits. The PSC has recognized that the "core benefits" of AMI include avoided T&D infrastructure, avoided capital costs, capacity and energy revenues, capacity and energy price mitigation, and energy conservation.[9] The important point is that these categories represent actions which would normally be associated with allocation methods other than "Customer." Furthermore, these benefits are not simply internalized to the customer served by the meter, but instead produce externality and system benefits.

[8] 2018 ECCOS Workpapers, Part 1. Sheets: "Meter (AMI) CUS370DIR" and "Meters 370."
[9] Order No. 87591 at 54-55, Case No. 9406.

Q. WHAT IS YOUR RECOMMENDATION?

A. My recommendation is to allocate 70% of the AMI meter costs on the basis used by the Company, since that percentage is a reasonable proxy for the amount that would have been expended to replace existing meters with non-AMI meters. The remaining 30% of the AMI meter cost is allocated on the basis of class energy use (excluding classes P, SL, PL, and T), which is termed the Energy Conservation Rate Base allocation factor in the ECCOS study. This adjustment is conservative, because, absent the AMI program, most of electro-mechanical meters would not have been replaced at this time. Therefore, applying a non-customer allocator to more than 30% of the meter cost could be justified.

Q. WHY IS YOUR ALLOCATION ADJUSTMENT REASONABLE?

A. My recommendation recognizes cost causation by quantifying the increment of cost incurred to achieve system benefits associated with AMI functionality. The use of an energy allocation factor recognizes that the externality benefits are strongly linked to energy conservation. Furthermore, the allocation reflects overall consumption of energy and utility services.

Q. DID YOU APPLY THE SAME ADJUSTMENT TO THE GAS CCOS STUDY?

A. No. I did not do so at this time. I have not reviewed sufficient information regarding the costs and benefits of AMI meters on the gas distribution system. However, in theory a similar allocation adjustment to the gas utility system may be justified in the future.

E. Call Center Expense

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE ALLOCATION OF COSTS INCLUDED IN CUSTOMER RECORDS AND COLLECTION (A903)?

A. Yes. The Company incurred $23 million of call center expense during the test year. $15 million is assigned to the electric utility and $8 million is assigned to the gas utility. The overall A903 expense is allocated based on unweighted customer count. However, the Company's tabulation of the calls made to the call center indicates that a substantial percentage of the calls involve issues or subjects which are not customer-related. The call center provides communications for many functions within the Company which are not related to billing and collection. My recommendation is to allocate a portion of call center costs on a non-customer basis.

Q. HOW DID YOU QUANTIFY THE PORTION OF CALL CENTER EXPENSE WHICH IS CUSTOMER-RELATED?

A. The Company's workpapers for the SOS Administrative Services Adjustment provide a tabulation of call frequency by subject matter.[10] The Company calculates that 38% of the calls pertain to billing, credit, and collection.[11] In addition, I added "start, stop, move service" calls to arrive at a customer-related percentage of 56%.[12] The remaining subject matter of call center calls are varied, with categories such as: gas emergency, electric emergency, 911 dispatcher, general business inquiry, energy conservation,

[10] BGE's Voluntary Production BGEVP01- Attachment 6, SOS Administrative Adjustment COSS - FINAL.xlsx , sheet: "Call Center Allocation."
[11] Id.
[12] Id.

demand side management, business account services team, and new business and construction inquiries.[13]

Q. BASED ON THIS INFORMATION, HOW DID YOU ALLOCATE THE CALL CENTER EXPENSE?

A. I recommend allocating 55% of call center cost on the same customer basis used for the remainder of A903, and 45% of call center expense on the Total O&M allocator. The total O&M allocator reflects the overall allocation of expense for all functions of the utility. Applying the O&M allocator to part of the call center costs recognizes that the call center provides system benefits to the utility.

Q. IS IT REASONABLE TO USE CALL FREQUENCY PERCENTAGES TO ALLOCATE CALL CENTER COSTS?

A. Yes. In fact, the Company uses the same methodology to assign call center costs to the SOS service.

Q. DID YOU APPLY THIS SAME ALLOCATION PROCEDURE FOR CALL CENTER EXPENSE TO THE GAS CCOS STUDY?

A. Yes.

[13] Id.

F. Gas Accounts 363, 378, 379, 921

Q. HAVE YOU MADE ANY OTHER ALLOCATION ADJUSTMENTS TO THE GCCOS STUDY?

A. Yes. I recommend the allocation of A363, A378, and A379 on the basis of total throughput (energy). A363 pertains to purification facilities. A378 pertains to general measurement and regulation station equipment and A379 pertains to city gate measurement and regulation station equipment. The Company allocated A363 on the basis of Peak Day and A378 and A379 on the basis of NCP demand. In addition, I recommend that $1.17 million of electricity expense in A921 should be allocated on the basis of total throughput and NCP demand.

Q. WHY DO YOU RECOMMEND THIS ALLOCATION CHANGE?

A. Purification refers to the process of removing impurities from the gas supply. The purification process is required in order to make the gas useful and safe. Impurities must be removed from delivered gas for all time periods, and the process is not limited to gas delivered during the peak day or a particular peak hour. Therefore, annual throughput is a more reasonable allocation for A363. Similarly, odorization of gas is legally required as a safety measure. The odorization is not limited to gas delivered during peak hours but is a general requirement for the commodity. Odorization costs are recordable in A378 and A379. Furthermore, the measurement and regulation functions in A378 and A379 are necessary for all hours of gas delivery, not just the peak hour. Therefore, annual throughput is a reasonable allocation for A 378 and A379.

Q. PLEASE EXPLAIN THE ALLOCATION OF ELECTRICITY EXPENSE.

A. The electricity consumed by the gas delivery system is recorded in A921 (Office Supplies & Expense). The expenses in this account are allocated on a labor basis. The Company states that 74% of the electricity expense is billed on a kWh basis, and 25% is billed on a demand charge basis.[14] My recommendation is to allocate the $872 thousand of kWh billed electricity on the basis of total throughput and $294 thousand of electricity demand charges on the basis of NCP demand. The recommended allocation changes are consistent with the kWh and demand charge bills associated with the consumption of electricity by the gas distribution system.

G. Conclusion

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED CHANGES TO THE ECCOS STUDY?

A. The change in allocated costs by class if the recommended allocation adjustments are adopted is shown below. The impact is based on the difference between the Company's filed ECCOS required revenues by class and the class required revenues after my recommended adjustments are incorporated in the ECCOS study.

[14] BGE Response to OPC DR 8-15. (Included as Attachment E to this testimony.)

	CUMULATIVE IMPACT
Class	
R	**(9,995,737)**
RL	**(206,279)**
G	**684,117**
GS	**248,380**
GL	**7,115,510**
P	**1,602,781**
SL	**374,304**
PL	**150,907**
T	**26,018**

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDED CHANGES TO THE GCCOS STUDY?

A. The change in gas utility allocated costs by class if the recommended allocation adjustments are adopted is shown below. The impact is based on the difference between the Company's filed GCCOS required revenues by class and the class required revenues after my recommended adjustments are incorporated in the GCCOS study.

	CUMULATIVE IMPACT
Class	
D	(6,007,328)
C	2,973,367
ISS	95,483
IS	2,353,904
EG	583,593
PLG	981

Q. HAVE YOU PREPARED SCHEDULES WHICH SUMMARIZE THE CCOS STUDY RESULTS?

A. Yes. Schedule CJ-1 provides information on the ECCOS study results, and Schedule CJ-2 provides information on the GCCOS study results.

III. CLASS REVENUE DISTRIBUTION

A. OVERVIEW

Q. WHAT IS THE RELATIONSHIP BETWEEN CLASS COST OF SERVICE RESULTS AND CLASS REVENUE DISTRIBUTION?

A. Class revenue distribution refers to the change in revenues assigned to each customer class. The class revenue assignment will provide a target for the amount of revenues to be collected through the design of new rates for each customer class.

Q. DO REGULATORY PRINCIPLES SUPPORT THE CONSIDERATION OF FACTORS THAT MAY LEAD TO MODERATING CCOS RESULTS?

A. Yes. Non-cost considerations are appropriate in mitigating pure CCOS results when necessary to effectuate the public interest. This principle has been recognized in longstanding regulatory texts, such as the oft-quoted Dr. James Bonbright's seminal *Principles of Public Utility Rates*.[15] This treatise, frequently cited by regulatory commissions, explains eight non-cost attributes of a sound rate design that include: (1) "simplicity" and "understandability;" (2) "public acceptability;" (3) "freedom from controversy;" (4) "revenue stability;" (5) "stability of the rates…with a minimum of unexpected changes seriously adverse to existing customers;" (6) "fairness… in the apportionment of total costs of service among the different consumers," (7) "avoidance of undue discrimination," and (8) "efficiency…in discouraging wasteful use of service."[16]

[15] Bonbright, *Principles of Public Utility Rates* at 291, (Columbia Press 1961).
[16] *Id.*

B. RATE MODERATION

Q. DO YOU FAVOR THE APPLICATION OF RATE MODERATION IN THIS CASE?

A. Yes. And this general view appears to be shared by BGE witness Fiery, who proposes moderation in applying CCOS study results to the class revenue distribution.

Q. DO YOU HAVE RESERVATIONS ABOUT THE PRECISION WHICH SHOULD BE ASCRIBED TO CCOS RESULTS?

A. Yes. CCOS studies are imprecise instruments. The studies will allocate costs to a multiple decimal point level, but this may provide a false sense of security about the accuracy of the studies. This conclusion is based on two general reservations regarding embedded CCOS studies.

First, subjective judgment enters into the selection and development of classification and allocation methods. The CCOS results may be quite sensitive to alternative classification or allocation decisions which are within a range of reasonable choices. As a result, it may be more appropriate to characterize the CCOS in the form of a range of acceptable rates of return instead of a single point estimate.

Second, CCOS studies are a static snapshot of the dynamic relationship between supply and demand. Both costs and class usage characteristics will change over various time periods. For these reasons, some degree of judgment may be appropriate in applying the CCOS study to class revenue increases. “Cost based rates” are best viewed as representing a reasonable band around the CCOS results, rather than exact price points. Furthermore, CCOS studies which do not recognize the differences in risk associated with customer classes should be utilized cautiously.

Q. PLEASE DISCUSS YOUR RECOMMENDATION REGARDING THE ELECTRIC REVENUE DISTRIBUTION THAT THE COMPANY APPLIES TO THE RESIDENTIAL CLASS.

A. Company witness Fiery targets a revenue increase for the residential class which is intended to move the class' relative rate of return (RROR) 50% of the distance to a 0.9 RROR. Class revenue increases can be expressed as a ratio of the total system percentage revenue increase. The ultimate result of the Company's method is a residential percentage increase which is 126% of the system average percent increase.[17] However, my recommended CCOS study changes would permit the residential class to achieve the Company's target for the class with a lower revenue increase. If the impact of the CCOS study changes on the residential class are combined with the Company's target for the class, the residential percentage increase could be reduced to 102% of the system average increase.[18] Given this context, my recommendation is to cap the residential increase at 110% of the system average increase.

Q. PLEASE DISCUSS YOUR RECOMMENDATION REGARDING THE GAS REVENUE DISTRIBUTION THAT THE COMPANY APPLIES TO THE RESIDENTIAL CLASS.

A. Company witness Fiery adopts a residential percentage increase which is slightly above 100% of the system average percent increase.[19] However, my recommended CCOS

[17] 10.7% residential increase compared to 8.47% system percentage increase.
[18] 8.69% residential increase compared to 8.47% system percentage increase.
[19] 13.96% residential increase compared to 13.93% system percentage increase.

study changes would increase the residential RROR substantially above unity and justify a residential percentage increase below the system average percent. If the impact of the CCOS study changes on the residential class are deducted from the Company's proposed revenue increase for the class, the residential percentage increase could be reduced to 89% of the system average increase.[20] Given this context, my recommendation is to cap the residential increase at 95% of the system average increase.

IV. RESIDENTIAL CUSTOMER CHARGE

Q. WHAT IS BGE'S PROPOSALS REGARDING THE ELECTRIC AND GAS RESIDENTIAL CUSTOMER CHARGE?

A. For the electric utility, the Company proposes to increase the residential customer charge from the current level of $7.90 to $10.00. This is a 26% increase in the monthly charge. For the gas utility, the Company proposes to increase the residential customer charge from $14 to $16, which is a 14% increase.

Q. DO YOU AGREE WITH THE INCREASE PROPOSED FOR THE CUSTOMER CHARGE?

A. No. The customer charge does not provide price signals which are particularly relevant to resource allocation. In the rate making process, the customer charge level is closely linked to the utility's usage rates (per kWh and per kW), since costs which are not collected through the customer charge will be recovered through the usage rates. Because the electric utility cost structure is dominated by costs which vary with

[20] 12.2% residential increase compared to 13.9% system percentage increase.

changes in demand and annual electric load over the long run, the usage-sensitive rate is the primary source of meaningful price signals. A lower customer charge ensures that a greater proportion of costs are recovered through a usage-sensitive price. A lower customer charge is more consistent with energy conservation goals and provides pricing policies appropriate for consumption of finite natural resources. In addition, a policy that minimizes the customer charge is more equitable to low usage residential customers.

Q. TAKING INTO ACCOUNT THE POLICY CONSIDERATIONS RELEVANT TO THE CUSTOMER CHARGE LEVEL, WHAT IS AN APPROPRIATE BENCHMARK FOR SETTING THE CUSTOMER CHARGE?

A. The customer charge should recover costs which directly vary with the number of customers, and this is the appropriate benchmark for determining whether the customer charge is compensatory. Public policy supports the use of a narrow measure of costs for the monthly fixed charge. The only economic pricing function of a customer charge is to ration access to the utility system; and public policy favors expansion, rather than limitation, of public access to the regulated monopoly's essential services. There is ample reason to base the customer charge on the following basic components: O&M expense for meters, services, meter reading, and customer accounting, and return and depreciation on meter and service investment, minus credits for customer deposits and related deferred federal income taxes. In my view, general overhead, such as administrative and general expense, and customer classified costs which are weakly related (if at all) to customer count (such as informational and advertising accounts), should be excluded from the customer charge computation, because these costs do not vary directly with number of customers.[21] The customer charge is compensatory so long as it recovers the expenses which are required to maintain the residential customer on the system. According to the Company, if a customer terminates service and is not replaced by another customer at the same premises, the Company receives no savings in customer classified costs.[22] This strongly implies that a substantial portion of the customer classified costs in the proposed customer charge do not vary with changes in the number of customers.

Q. HAVE YOU PERFORMED AN ANALYSIS OF THE APPROPRIATE BENCHMARK FOR EVALUATING BGE'S RESIDENTIAL CUSTOMER CHARGE?

A. Yes. Schedule CJ-3 shows my customer charge calculations based only on direct or basic customer costs. The direct customer charge includes services and meters, O&M expenses for services and meters, customer accounting and meter reading expense, and deductions for customer-related deposits and ADFIT. The calculation does not include indirect costs, such as the bulk of A&G expenses, which by definition are not directly related to any utility function. My calculation also excludes uncollectible expense from the residential customer charge because the amount of uncollectible expense is driven by the size of customer bills which are unpaid, which is a usage sensitive characteristic. The inclusion of uncollectible expense in the Company's customer charge occurs because uncollectible expense is recorded in customer accounting; however, the act of recording the expense in a customer account does not mean that the cost varies directly

[21] The calculation of direct customer costs for my customer charge analysis includes limited employee benefit expense related to amount of direct customer –related personnel.
[22] BGE Response to OPC DR 5-30. (Included as Attachment F to this testimony.)

with number of customers.[23] In addition, I have excluded customer service and sales expense (FERC Accounts 908 – 916), which are indirect costs largely unrelated to billing. In addition, the advertising, promotional, and economic development expenses recorded in these accounts are not appropriately recovered through a monthly customer charge. As shown on Schedule CJ-3, the basic residential customer charge for BGE electric service is calculated at $5.54, and $10.85 for BGE gas service. The current customer charge for both electric and gas exceeds direct costs and provides a substantial contribution to recovery of indirect costs.

Q. DOES ENERGY CONSERVATION POLICY FAVOR THIS APPROACH?

A. Yes. In weighing the appropriateness of limited versus broad calculations of the customer charge, the Commission should consider the effect on energy efficiency policies. A high customer charge tends to inhibit energy conservation. Minimizing the customer charge provides the ratepayer with a greater ability to control his/her bill on the basis of usage. For that reason, an excessive customer charge can promote wasteful energy consumption. Maryland's policy favoring energy efficiency, as evidenced by directives requiring utility funded energy conservation programs, provides convincing support for utilizing a basic customer charge benchmark. Public utilities have an incentive to propose higher fixed charges because the fixed nature of the charges produce less financial risk; however, they do not propose to compensate customers for the lower risk through a reduction in the allowable return on equity. Ms. Fiery's contends that recovering fixed costs through usage rates provides an incorrect price

[23] Note that the NARUC Electric Utility Cost Allocation Manual (CAM) specifically excludes uncollectibles from the customer classification. CAM at 103.

signal.[24] But this argument essentially implies a position that residential customers should consume more energy. In my view, that conclusion is inconsistent with the policy reasons for reducing energy usage and the accompanying externality costs.

Q. DOES COMPANY WITNESS FIERY CONTEND THAT THE PROPOSED CUSTOMER CHARGE INCREASE IS TOO SMALL TO AFFECT ENERGY CONSERVATINO INCENTIVES?

A. Yes. However, I do not agree with her argument. First, based on Ms. Fiery's testimony regarding the appropriate recovery of fixed costs, clearly the Company views the current gradual increases in the customer charge as a bridge to eventually achieving the higher customer charge numbers produced by the CCOS study. Second, despite attempts to describe the customer charge increase as too insubstantial to affect consumption behavior, even relatively small changes in the customer charge can affect the perceived cost effectiveness of energy efficiency choices.

Q. CAN YOU PROVIDE AN ILLUSTRATION OF THE IMPACT OF CUSTOMER CHARGE METHODS ON ENERGY EFFICIENCY CHOICES?

A. Yes. I performed a comparison of the net life cycle savings, as measured by the present value of bill savings, and payback periods for Energy Star central air conditioning relative to less efficient air conditioning options.[25] I prepared a comparison of net life

[24] I disagree with the argument that fixed cost must be recovered in customer charges and only variable costs may be recovered through usage charges. The distinction between fixed and variable cost is not particularly useful. From an economic perspective, all of the firm's costs are fixed in the short run, while all costs are variable in the long run. In most cases, long run costs are more important in evaluating cost causation. The impact of rate design on the utility's long run investment decisions is generally of more significance to the regulator, because customer consumption decisions can influence the utility's cost structure over the longer time horizon.

[25] I utilized Energy Star spreadsheets which were developed for the EPA and U.S. Department of Energy. The spreadsheet includes inputs for location (Baltimore) and electric rates. This comparison is for an 18 SEER air conditioner compared to a 13 SEER air conditioner. Net life cycle benefit refers to the present value of operating savings minus the initial price differential between the two appliance options

cycle savings for purchasing the more efficient appliance based on maintaining the current customer charge versus both the claimed customer charge justified by the Company's CCOSS ($16.13) and the requested customer charge ($10.00), assuming the Company's' proposed residential revenue requirement.[26] Assuming a constant residential class revenue requirement, the lower current customer charge places higher revenue recovery on the energy rate component, thereby increasing the incentive for customers to engage in energy efficiency actions. My analysis indicates that the high efficiency air conditioning unit will produce net life cycle savings at the requested customer charge which are 75% less than if the current customer charge is retained. For the $16.13 customer charge produced by the Company's CCOS, 109% less net savings than the current $7.90 customer charge. Moreover, the payback period for the initial purchase price of the high efficiency air conditioner is 3% - 7% longer with the higher customer charges instead of the current customer charge. This analysis illustrates that increasing the customer charge has consequences in terms of discouraging energy conservation. Although the customer charge increase may reflect a small percentage change in the total bill's fixed charge percentage, as argued by Company witness Fiery, the impact on individual's energy efficiency decisions at the margin can be material. Schedule CJ-4 provide details regarding this analysis.

[26] This analysis is based on the residential billing for proposed delivery rates plus standard offer service generation rates.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RESIDENTIAL CUSTOMER CHARGE?

A. My primary recommendation is to maintain the residential customer charge at the current level for both the electric utility ($7.90) and the gas utility ($12.00). In the event that the Commission finds that some level of increase is necessary, my alternative recommendation is to cap the residential customer charge increase at the percentage increase in distribution revenues for the residential class.

V. <u>ADMINISTRATIVE CHARGE FOR SOS</u>

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING THE ADMINISTRATIVE CHARGE FOR STANDARD OFFER SERVICE?

A. BGE proposes a 1 mill administrative service adjustment for customers taking standard offer service. The revenues are credited back to the customer class paying the charge.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. This will result in a 51% increase in the current administrative charge applied to customers on SOS.[27] Given that more than 70% of residential customers take SOS service, the increase will impact a substantial number of customers within the residential class. Moreover, the Company has made no effort to determine whether the administrative adjustment amount is comparable to the administrative costs incurred by competitive suppliers. BGE has made no effort to research—even on a preliminary

[27] 1 mill administrative adjustment divided by the current 1.93 mills administrative charge.

basis—how much administrative costs are incurred by competitive suppliers.[28] Furthermore, BGE has not attempted to compare its administrative charge to any similar charges assigned to comparable standard offer service rates in other states.[29] Although the administrative adjustment is justified by proponents as a way to recognize the types of costs incurred by competitive suppliers, the Company has not provided a market benchmark to evaluate the reasonableness of the costs "allocated" to SOS customers.

Q. IS IT RELEVANT TO KNOW WHETHER THE ALLOCATED ADMINISTRATIVE ADJUSTMENT IS CONSISTENT WITH MARKET COSTS?

A. As I understand it, the purpose of the administrative adjustment is to "level the playing field" in the competitive electric market.[30] However, the Commission won't know if the allocated amount reasonably achieves that objective without knowing the administrative costs expended by competitive suppliers. In addition, the possibility that the fee is set too high could be equally as damaging as the condition that the Commission is trying to remedy. If the competitive suppliers view the SOS rate as a

[28] BGE Response to OPC DR 5-43. (Included as Attachment G to this testimony.)
[29] BGE Response to OPC DR 5-44. (Included as Attachment H to this testimony.)
[30] Although I do not completely agree that this objective is appropriate for setting SOS rates, if the administrative adjustment is proposed as a measure to fix a claimed problem in the market, it is reasonable to test how well it addresses the issue.

price umbrella, adding an excessive fee to the SOS rate could result in non-competitive behavior to the detriment of consumers.[31]

Q. IS SOS SERVICE STRICTLY COMPARABLE TO THE SERVICE OFFERED BY COMPETITIVE RETAILERS?

A. To a significant extent, no. Unlike the competitive supplier, the SOS provider must be prepared to serve the entire market if necessary. SOS stands in reserve for the competitive market in the event that competitive retailers lose their customers due to high rates or if the competitor ceases operations. For residential and small commercial customers, the SOS is required to select two year power contracts in PSC regulated bidding processes. Although this provides the benefit of more stable SOS prices, the fact that the requirement applies only to SOS means that competitors can undercut the SOS rate with shorter term power prices when market conditions are favorable. In addition, SOS must be available to all customers, even those who have been dropped or denied by competitive retailers due to credit/payment issues. SOS has an obligation to serve all customers, but competitive suppliers do not. The assumption that SOS enjoys a market advantage over competitive suppliers ignores the regulatory obligation imposed on the SOS provider which can be viewed as a handicap in the market. In that sense, the SOS product is not strictly comparable to the competitive supplier's

[31] A price umbrella refers to circumstances in which smaller firms adopt of pricing policy of setting their price just below the incumbent firm's price. In this instance, if the SOS product price is artificially high, customers may switch to lower competitive supplier prices which are not as low as competitively driven prices.

products. Consequently, it is unreasonable to artificially increase the SOS price based on the faulty premise that SOS should incur the same costs as competitors.

Q. IS THE BGE BILLING AND COLLECTION SYSTEM PROPERLY CONSIDERED A REGULATED DISTRIBUTION COST?

A. Yes. BGE directly bills all distribution charges to all customers.[32] BGE would require the investment in the billing system regardless of the existence of SOS. From that perspective, SOS is not the cause of the investment.

Q. PLEASE COMMENT ON SOME OF THE COSTS INCLUDED IN THE ADMINISTRATIVE ADJUSTMENT.

A. I am skeptical of including the amortized and unamortized cost of the billing system. These are sunk costs which do not represent prospective costs in the market. In addition, the billing software for the electric utility likely is more complex than the billing requirements of competitors. Yet these expenditures are almost one third of the total administrative adjustment. The time expended by regulatory, accounting, and legal personnel may involve regulatory filings specific to operating the SOS, and, therefore, may not be representative of market costs. But these expenditures may be valid costs directly associated with SOS. However, these expenditures are less than 1% of the administrative adjustment.

[32] BGE Response to OPC DR 8-10. (Included as Attachment I to this testimony.)

Q. DO YOU HAVE ANY CONCERNS REGARDING THE INTRA-CLASS IMPACT OF THE ADMINISTRATIVE ADJUSTMENT?

A. According to the Company, the likely effect of the SOS adjustment, in combination with the revenue credit, is to increase electric bills of customers who take SOS service and decrease electric bills of customers who contract with competitive suppliers.[33] This pattern will create intra-class cross-subsidies; essentially customers who remain on SOS will be forced to subsidize customers who contract with competitive suppliers. While this may encourage some SOS customers to shop for a competitive supplier, it is possible (perhaps likely) that many of the customers will remain on SOS. The customer segments that are less inclined to shop for electricity may include less sophisticated customers and elderly low income ratepayers--the types of customers who often require regulatory protection. These customers would disproportionately fall within the subset of residential customers who sustain a net bill increase from the administrative adjustment. Given the Company's proposal for periodic changes to the adjustment, the intra-class impact may become more noticeable as the fee grows in the future. For this reason, the Commission should be conservative in approving expenditures for the adjustment.

Q. CAN YOU PROVIDE AN EXAMPLE AS TO HOW THE COMPANY'S ADMINISTRATIVE ADJUSTMENT METHODOLOGY COULD RAISE CROSS SUBSIDY QUESTIONS?

A. Yes. The Company's proposed allocation of call center costs to the SOS rate is illustrative. Approximately $15 million of call center expense is assigned to electric

[33] BGE Response to OPC DR 5-45. (Included as Attachment J to this testimony.)

distribution. 38.5% of the calls made to the call center involve billing inquiries or collections. The Company assumes that 45.6% of these billing and collection calls are assignable to SOS based on the commodity revenues as a percent of total revenues. Multiplying the total call center expense by 38.5% and 45.6% results in an allocation of $2.6 million to SOS.[34] The remaining 54.4% of billing and collection calls are not assigned to competitive suppliers, but instead remains in distribution expense, which means that it is paid by both SOS and competitive supplier customers. The Company admits that customers of competitive suppliers call the BGE call center.[35] But the Company does not track the data necessary to quantify the amount. [36] To the extent that these calls fall within the billing category (which is assigned to the SOS administrative charge), SOS customers are subsidizing the call center use by customers of competitive suppliers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes.

[34] BGE Response to OPC DR 5-40. (Included as Attachment K to this testimony.)
[35] BGE Response to OPC DR 5-37. (Included as Attachment L to this testimony.)
[36] Id.

SUMMARY OF QUALIFICATIONS

CLARENCE JOHNSON

EDUCATION

Bachelor of Science, Political Science, University of Houston.

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

EXPERIENCE

Mr. Johnson has more than 35 years experience as an expert witness and analyst related to electric and telecommunications utility issues.

CURRENT EMPLOYMENT

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

PREVIOUS EMPLOYMENT 1983-2008

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

EMPLOYMENT BEFORE 1983

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

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

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

MEMBERSHIP American Economics Association.

TESTIMONY ON BEHALF OF TEXAS OFFICE OF PUBLIC UTILITY COUNSEL	Docket No. 6588, Subject:	Re Southwestern Bell Telephone Company, Declassification of Documents.
	Docket Nos. 7195 and 6755, Subject:	Re Gulf States Utilities Company, Rate Design/Cost Allocation.
	Docket No. 7510, Subject:	Re West Texas Utilities Company, Rate Design/Cost Allocation.
	Docket No. 8095, Subject:	Re Texas-New Mexico Power Company, Rate Design/Cost Allocation.
	Docket No. 8363, Subject:	Re El Paso Electric Company, Rate Design/Cost Allocation.
	Docket No. 8425, Subject:	Re Houston Lighting & Power Company, Revenue Requirements.
	Docket No. 8425, Subject:	Re Houston Lighting & Power Company, Rate Design/Cost Allocation.
	Docket No. 8646, Subject:	Re Central Power and Light Company, Revenue Requirements.
	Docket No. 8646, Subject:	Re Central Power and Light Company, Rate Design/Cost Allocation.
	Docket No. 8646, Subject:	Re Central Power and Light Company, Interim Rate Relief.
	Docket No. 8555, Subject:	Proceedings Concerning Houston Lighting & Power Company on Remand From Cause No. C-5705 and Cause No. 352,044, Determination of Remand Amount.
	Docket No. 8928, Subject:	Re Texas-New Mexico Power Company, Rate Design/Cost Allocation.
	Docket No. 8585, Subject:	Re Southwestern Bell Telephone Company, Revenue Requirements/Affiliates.
	Docket No. 8585, Subject:	Re Southwestern Bell Telephone Company, Reply, Revenue Requirements/Affiliates.

Docket No. 8585, Subject:	Re Southwestern Bell Telephone Company, Reply, Rate Design.
Docket No. 8585, Subject:	Southwestern Bell Telephone Company, Proposed Non-Unanimous Stipulation.
Docket No. 9300, Subject:	Texas Utilities Electric Company, Revenue Requirement.
Docket No. 9300, Subject:	Texas Utilities Electric Company, Cost Allocation and Rate Design.
Docket No. 9300, Subject:	Texas Utilities Electric Company, Prudence of Plant Acquisition.
Docket No. 9561, Subject:	Central Power and Light Company, Revenue Requirement.
Docket No. 9561, Subject:	Central Power and Light Company, Cost Allocation and Rate Design.
Docket No. 9578, Subject:	Sugar Land Telephone Company, Inquiry into Sale.
Docket No. 9850, Subject:	Houston Lighting & Power Company, Revenue Requirement.
Docket No. 9850, Subject:	Houston Lighting & Power Company, Cost Allocation and Rate Design.
Docket No. 9850, Subject:	Houston Lighting & Power Company, Settlement Testimony: Revenue Requirement and Rate Design.
Docket No. 9981, Subject:	Central Telephone Company, Revenue Requirement/Affiliates.
Docket No. 10894, Subject:	Gulf States Utilities Company, Affiliate Transactions/Power Purchases.
Docket No. 11735, Subject:	Texas Utilities Electric Company, Revenue Requirement and Rate Design.

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

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

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

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

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

Docket No. 33310,	Application of AEP Texas North Company for Authority to Change Rates,
Subject	Energy Efficiency Costs and Riders.
Docket No. 32902,	CenterPoint Energy Houston Electric, LLC Compliance Tariff,
Subject:	Allocation of Stranded Costs.
Docket No. 34077,	Joint Report and Application of Oncor and EFH Pursuant to § 14.101,
Subject:	Leveraged buyout of utility.
Docket No. 35105,	Compliance Tariff Filing of AEP Texas,
Subject:	Allocation of Stranded Costs.
Docket No. 35038,	Texas-New Mexico Power Company Tariff Filing in Compliance with the Final Order in Docket No. 33106,
Subject:	Allocation of Stranded Costs.
Docket No. 34800,	Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs,
Subject:	Cost Allocation & Rate Design.
*Docket No. 37482,	Application of Entergy Texas for a PCRF,
Subject:	Purchase Power.
*Docket No. 37744,	Application of Entergy Texas, Inc. for Authority to Change Rates,
Subject:	Cost allocation, rate design, proposed riders, & storm damage expense.
*Docket No. 38951,	Application of Entergy Texas, Inc. for Approval of CGS Tariff,
Subject:	Rate Design, Competitive Tariffs.
*Docket No. 46454,	Application of SPS for Revision of EECRF[1],
Subject:	Recovery of energy efficiency costs.

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

TESTIMONY ON BEHALF OF STEERING COMMITTEE OF ONCOR CITIES	Docket No. 35634, Subject:	Re Oncor Electric Delivery's Request for an Energy Efficiency Cost Recovery Factor, Energy Efficiency Cost Recovery.
	Docket No. 36958, Subject:	Application of Oncor Electric Delivery Company LLC for 2010 Energy Efficiency Cost Recovery Factor, Energy Efficiency Cost Recovery.
	Docket No. 39375, Subject:	Application of Oncor Electric Delivery Company LLC for 2012 EECRF, Energy Efficiency Cost Recovery.
TESTIMONY ON BEHALF OF ALLIANCE OF XCEL MUNICI-PALITIES	Docket No. 35664, Subject:	Application of SPS to Revise Interruptible Credit Option Tariff, Interruptible Rate Avoided Costs.
	Docket No. 35763, Subject:	Application of SPS to Change Rates and Reconcile Fuel and Purchased Power Costs, Energy Efficiency, Renewable Energy Credits, Power Cost Credits, and Interruptible Credits.
	Docket No. 37173, Subject:	Petition for Declaratory Order of Southwestern Public Service Company Regarding the Generation Demand Charge as a Cap on Compensation for Interruptible Resources Interruptible Curtailable Option ("ICO").
	Docket No. 43695, Subject:	Application of SPS to Change Base Rates, Cost Allocation / Rate Design/ Jurisdictional.
	Docket No. 47527, Subject:	Application of SPS to Change Base Rates, Cost Allocation / Rate Design/ Jurisdictional
TESTIMONY ON BEHALF OF CERTAIN TNMP CITIES	Docket No. 36025, Subject:	Application of TNMP for Authority to Change Rates, Cost Allocation and Rate Design.
	Docket No. 39362, Subject:	Application of TNMP for 2012 EECRF, Energy Efficiency Cost Recovery.

TESTIMONY ON BEHALF OF ST.LAWRENCE COTTON GROWERS	Docket No. 41474, Subject:	Application of Sharyland Utilities for Unbundled Delivery Rates, Cost Allocation, Rate Design, Unbundling.
TESTIMONY ON BEHALF OF LIVE OAK TENANTS	Docket No.41987, Subject:	Complaint Against Live Oak Resort, Sub Metering Complaint Case.
TESTIMONY ON BEHALF OF GULF COAST COALITION OF CITIES	Docket No. 38339, Subject:	Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates, Cost Allocation, Rate Design, Riders.
TESTIMONY ON BEHALF OF PENNYSLVANIA OFFICE OF CONSUMER ADVOCATE	Docket No. R-2010-2161575, et. al., Subject:	PECO Energy Co.-Electric Division Base Rate Case, Cost Allocation and Rate Design.
	Docket No. R-2010-2179522, Subject:	Duquesne Light Company Base Rate Case, Cost Allocation and Rate Design.
	Docket No. R-2014-248745, Subject:	Met Edison General Base Rate Case, Cost Allocation and Rate Design.
	Docket No. R-2014-2478743, Subject:	Penelec Power General Base Rate Case, Cost Allocation and Rate Design.
	Docket No. R-2014-2478744, Subject:	Penn Power General Base Rate Case, Cost Allocation and Rate Design.
	Docket No. R-2014-248752,	West Penn Power General Base Rate Case,

	Subject:	Cost Allocation and Rate Design.
	Docket No. R-2016-2537349 Subject:	Met Edison General Base Rate Case, Cost Allocation and Rate Design.
	Docket No. R-2016-2537352 Subject:	Penelec Power General Base Rate Case, Cost Allocation and Rate Design.
	Docket No. R-2016-2537355, Subject:	Penn Power General Base Rates, Cost Allocation and Rate Design.
	Docket No. R-2016-2537359 Subject:	West Penn Power General Base Rate Case, Cost Allocation and Rate Design.
	Docket No. R-2018-3000164 Subject:	PECO General Rate Case Cost Allocation and Rate Design

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TESTIMONY ON BEHALF OF SWEPCO CITIES	Docket No. 40443, Subject:	Application of SWEPCO for Rate Change, Cost Allocation, Rate Design, Fuel Rule, Revs.
TESTIMONY ON BEHALF OF SWEPCO CITIES (CARD)	Docket No. 46449, Subject:	Application of SWEPCO for Rate Change, Cost Allocation, Rate Design, Transmission.

Gas Utility (Railroad Commission):

TESTIMONY FOR CITY OF EL PASO	Docket No.10506 Subject:	Texas Gas Services Co.-West Texas Cost Allocation, Rate Design

TESTIMONY FOR CONNECTICUT CONSUMER COUNSEL	Docket No.14-05-06,	CL&P Rate Increase Application,
	Subject:	Cost Allocation, Rate Design, Decoupling.
TESTIMONY FOR TEXAS COAST UTILITIES COALITION	Docket No.44572,	Centerpoint Application for DCRF,
	Subject:	Distribution Cost Recovery Factor.
	Docket No. 47320,	Centerpoint Application for DCRF,
	Subject:	Distribution Cost Recovery Factor.
TESTIMONY FOR CITY OF EL PASO	Docket No.44941,	El Paso Electric Co. Rate Request,
	Subject:	Cost Allocation, Rate Design.
	Docket No. 46831	EPEC Rate Case
	Subject:	Cost Allocation/Rate Design
	Docket No. 48181	EPEC Community Solar Waiver
	Subject:	Regulatory Policy
TESTIMONY FOR TEXAS OPUC (2014 or later)	Docket No.44620,	Sharyland Utilities Good Cause Request,
	Subject:	Transmission Cost Recovery.
	Docket No. 45414, (base rate)	Sharyland Utilities Rate Inquiry,
	Subject:	Rev Req/Allocation/Rate Design.
	Docket No. 46025, (fuel)	Southwestern Public Service Co.,
	Subject:	Fuel and Purchased Power.
	Docket No. 48371,	Entergy Texas Rate Application
		Class Allocation/Rate Design/Riders

TESTIMONY FOR CITIES SERVED BY AEP	Docket No.49494, Subject:	Application of AEP Texas to Adjust Rates Cost Allocation/Rate Design

Case No. 9610
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: 08/05/2019
Response Date: 08/19/2019

Item No.: OPCDR05-08

Please:

a. Identify the number of executives, marketing personnel, and customer assistance staff, including Key account managers and representatives, who are involved primarily in contacts with current or prospective large commercial or industrial customers;

b. Indicate whether the individuals are employed by an affiliated service company or the utility operating company;

c. Identify the particular rate classes supported by the personnel;

d. Describe the types of services performed by the staff listed in 'a';

e. Provide the annual costs for the personnel identified in (a), including associated overheads, by FERC account; and

f. Explain how the costs described in this request are allocated in the CCOS study.

RESPONSE:

a. BGE's Large Customer Services group falls under the Senior Vice President of Regulatory and External Affairs. The Vice President of Governmental and External Affairs reports directly to the Senior Vice President and oversees the Senior Manager of Large Customer Services. The Senior Manager of Large Customer Services has three direct reports: two first-line managers and one administrative assistant. The two first-line managers have responsibility for fourteen Senior Account Representatives.

b. The members of the Large Customer Services group are BGE employees.

c. The rate classes containing the largest customers would, for the most part, comprise the rate classes supported by Large Customer Services, namely Schedules GL, P, and T for electric and large gas customers in Schedules IS and C. However, customers from other classes could also be included depending on the circumstances.

d. The Large Customer Services group performs the following services:

- Establish and develop strong professional relationships with the largest industrial, commercial and government (federal, state and local) customers; these customers have one or more of the following attributes: complex infrastructures and significant energy demands; serve or are responsible to a large constituency, county, community or similar base (ex. AA County, Towson University); business operations provide life/safety services that if interrupted significant loss of life could occur (ex. Hospitals); and national customer with a significant presence in the BGE service territory.

- Proactively educate our large customers about BGE programs, applications of energy products and services, various incentive programs (BGE or State), provide high level technical assistance, discuss supply and rate alternatives.

- Lead and/or assist with coordination, resolution and/or facilitation of services between the customer and BGE engineering, application of customer equipment, restoration, reliability, billing, conservation, energy and load management.

- Update and maintain specific and pertinent customer information, including contact, customer concerns and resolution. Provide applicable customer information to internal stakeholders to support BGE service and/or restoration efforts.

- As the "voice of the customer" develop, engage, support and maintain key account internal partnerships to drive high large customer satisfaction through continuous process improvement initiatives and communication.

e. See *Attachment 1*.

f. See Attachment 1.

Case No. 9610
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: 08/05/2019
Response Date: 08/19/2019

Item No.: OPCDR05-10

If advertising expenses are included in A930, provide the amount and explain the purpose of the advertising. Provide examples or proofs of the advertisements. Please provide this information for both the electric and gas CCOS study.

RESPONSE:

Promotional advertising costs are recorded in Account 930.1 – General Advertising Expenditures ($648,631 and $333,397 for electric and gas, respectively). This account is used for the cost of advertising activities of an institutional nature, directed at establishing a favorable image of the utility or its employees. For purposes of the revenue requirement calculation, these costs are removed from cost of service in Company Witness Vahos's Exhibits (See Operating Income Adjustment 1).

Please refer to *Attachments 1* through *3* for examples of promotional advertising for BGE.

Case No.
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: 08/05/2019
Response Date: 08/19/2019

Item No.: OPCDR05-22

Please provide a more detailed breakdown of the programs and activities encompassed in A909 and A910, and explain why the class allocation applied to those accounts is appropriate.

RESPONSE:

Please refer to *Attachment 1* for a detailed breakdown of the activities encompassed in FERC Account 909 – Informational and Instructional Advertising. Please refer to *Attachment 2* for a detailed breakdown of the activities encompassed in FERC Account 910 – Miscellaneous Customer Service and Informational Expense.

The costs in Accounts 909 and 910 are allocated between customer classes using an allocator that is based on the average number of customers for each rate class. This allocator is classified as customer-related, as opposed to demand- or usage-related, and is appropriate due to the activities being informational in nature and not targeted to a specific class of customer.

Case No. 9610
Baltimore Gas and Electric Co.
Response to OPC Data Request 8
Request Received: 08/21/2019
Response Date: 09/05/2019

Item No.: OPCDR08-15

(a) With respect to the GCCOS study, please break out the electricity service expense incurred to deliver gas. Identify the FERC account associated with the expense. (b) What percentage of the electricity expense is: (i.) incurred due to a demand charge or ratchet; (ii.) billed on a kwh or energy basis; and (iii.) incurred for a customer charge.

RESPONSE:

a. Electric expense incurred to support gas distribution for calendar year 2018 is $1,179,800 and is charged to FERC account 921.

b. Of the total electric expense: 25% is incurred due to a demand charge; 74% is billed on a kWh basis; and 1% is incurred for a customer charge.

Case No. 9610
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: 08/05/2019
Response Date: 08/19/2019

Item No.: OPCDR05-30

If a customer terminates service and is not replaced by a new customer at the same premises, please identify any customer classified costs which would cease to be incurred or any resulting savings in customer classified costs.

RESPONSE:

There would be no such costs or savings.

Case No. 9610
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: 08/05/2019
Response Date: 08/19/2019

Item No.: OPCDR05-43

Did the Company attempt to evaluate competitive supplier costs? If yes, provide any data that the Company collected as a preliminary effort to study that issue.

RESPONSE:

No, see the Direct Testimony of Company Witness Manuel, page 30.

Case No. 9610
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: 08/05/2019
Response Date: 08/19/2019

Item No.: OPCDR05-44

Has the Company made an effort to compare the SOS administrative costs it developed with the costs added to similar SOS or default services in other states with competition? If yes, provide any such information collected by the Company.

RESPONSE:

No.

Case No. 9610
Baltimore Gas and Electric Co.
Response to OPC Data Request 8
Request Received: 08/21/2019
Response Date: 09/05/2019

Item No.: OPCDR08-10

For those electric retail competitive suppliers that do not procure billing and collection services from BGE, does BGE directly bill the supplier for its customers' transmission-distribution rates, or does BGE send a bill to the end use customer for transmission distribution rates? If the competitive supplier is directly billed, please provide BGE's actual cost for preparing, producing, and collecting these TDU bills transmitted to competitive suppliers, and quantify the number of end use customers who do not receive a bill from BGE because billing is performed by the electric competitive supplier.

RESPONSE:

With respect to transmission, BGE recovers its transmission revenue requirement from PJM. PJM in turn bills load serving entities (LSEs) the appropriate network integration transmission service (NITS) expense and each load serving entity (including BGE) recovers that expense from its retail customers. LSEs (or competitive suppliers) not using BGE for billing and collection invoice their customers for both commodity and transmission independent of BGE.

With respect to distribution, BGE directly bills all distribution charges to all customers.

Case No. 9610
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: 08/05/2019
Response Date: 08/19/2019

Item No.: OPCDR05-45

What is the cost/customer increase (dollars and bill percentage) for SOS customers if the Company's administrative adder is adopted?

RESPONSE:

As approximately 75% of BGE's residential electric customers are on SOS, the typical residential electric customer's SOS portion of their bill is estimated to increase by $0.88 or 0.2% per month (i.e. 877 kWh x 1.0 mills per kWh) and the typical residential electric customer's distribution portion of their bill is estimated to decrease by $0.66 or 0.6% per month (i.e. 877 kWh x 1.0 mills per kWh x 75%).

Therefore, the net cost/customer increase for an SOS customer would be $0.22 per month ($0.88 - $0.66), while a non-SOS customer would experience a decrease of $0.66 per month.

See the Company's response to OPCDR05-34 for an explanation of the process the Company will use to simultaneously charge the Administrative Adjustment to SOS customers and credit that amount in full to all distribution customers.

Case No. 9610
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: 08/05/2019
Response Date: 08/19/2019

Item No.: OPCDR05-40

With respect to the call center allocation for the SOS administrative cost, please explain how the 38.5% ratio is applied in the calculation of the SOS administrative adder.

RESPONSE:

38.5% is the percentage of calls processed by BGE's Call Center in 2018 which relate to either billing or credit & collections and, for this reason, is allocable to SOS. The Call Center's total cost charged entirely to electric distribution in 2018 was $15,123,798. The portion of this total cost associated with billing and credit & collections calls is, therefore, $5,823,077 ($15,123,798 multiplied by the 38.5% allocation factor). The estimated cost of Call Center related billing and credit & collection costs multiplied by the electric commodity revenue allocation factor of 45.6% equals $2,655,323, which matches the total Call Center cost distributed among the various POLR types (Residential, Type I, Type II, and Hourly) in the proposed SOS administrative adjustment.

Please see BGE's Voluntary Production BGEVP01- Attachment 6, SOS Administrative Adjustment COSS - FINAL.xlsx. See also the Direct Testimony of Company Witness Manuel, page 32.

Case No. 9610
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: 08/05/2019
Response Date: 08/19/2019

Item No.: OPCDR05-37

Do any customers of competitive suppliers contact the BGE call center? If yes, quantify the amount and provide the protocol for handling consumer inquiries or complaints regarding their competitive supplier.

RESPONSE:

Customers with suppliers do contact the BGE call center. BGE does not track the data necessary to quantify this amount. If a customer has an inquiry or a complaint regarding the supplier charges, BGE will provide the supplier's contact information for the customer to contact the supplier directly. In the event that the complaint is not able to be resolved between the supplier and the customer, BGE directs the customer to contact the Maryland Public Service Commission for further assistance.

ADJUSTED ELECTRIC CCOS STUDY

	R	RL	G	GS	GL	P	SL	PL	T
	RESIDENTIAL	**RES TOD**	**GENERAL**	**GEN SM.**	**GEN LARGE**	**PRIMARY**	**ST LIGHT**	**AREA LTG**	**TRANS.**
FILED CCOS									
RROR	68.0%	89.4%	89.5%	148.4%	161.5%	115.7%	173.6%	423.4%	1302.7%
EQUALIZED REV REQ	$ 626,496,371	$ 44,188,614	$ 127,625,289	$ 9,029,860	$ 217,301,618	$ 78,226,180	$ 21,042,036	$ 8,540,514	$ 1,997,938
AS ADJUSTED									
RROR	73.3%	90.9%	87.3%	137.1%	150.0%	108.4%	168.4%	417.6%	1284.1%
EQUALIZED REV REQ	$ 616,500,635	$ 43,982,334	$ 128,309,406	$ 9,278,240	$ 224,417,128	$ 79,828,961	$ 21,416,339	$ 8,691,421	$ 2,023,956
DIFFERENCE	$ (9,995,737)	$ (206,279)	$ 684,117	$ 248,380	$ 7,115,510	$ 1,602,781	$ 374,304	$ 150,907	$ 26,018

Notes:
"RROR" is Relative Rate of Return.
"Equalized"means class rates of return are set equal to system rate of return.
Revenue requirements based upon Company's request.
"Difference" refers to change produced by adjusted allocation factors.

ADJUSTED GAS CCOS STUDY

	RESIDENTIAL D	GS C	SMALL INTER. ISS	LARGE INTER. IS	GENERATION EG	LIGHTING PLG
FILED CCOS						
RROR	101.5%	93.9%	137.5%	71.9%	423.3%	980.2%
EQUALIZED REV REQ	$ 352,599,216	$ 133,633,364	$ 2,083,101	$ 25,726,855	$ 3,492,257	$ 7,051
AS ADJUSTED						
RROR	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
EQUALIZED REV REQ	$ 346,591,888	$ 136,606,731	$ 2,178,585	$ 28,080,760	$ 4,075,849	$ 8,031
DIFFERENCE	$ (6,007,328)	$ 2,973,367	$ 95,483	$ 2,353,904	$ 583,593	$ 981

Notes:
"RROR" is Relative Rate of Return.
"Equalized"means class rates of return are set equal to system rate of return.
Revenue requirements based upon Company's request.
"Difference" refers to change produced by adjusted allocation factors.

Residential Customer Charge

Electric Utility

Invested Capital	
Res Meters & Services	517,445,922
Accumulated Depreciation	285,418,634
Net Plant	232,027,287
ADFIT	-38,730,825
Customer Deposits	-8,928,740
Rate Base	184,367,722
Times Fixed Charge	$26,088,033

O&M Expense	
Res Meters-Operations	4,085,639
Res Meters-Maintenance	1,931,240
Customer Accounting A901-903	33,965,936
Related Pension & Benefits	7,555,120
Total Expense	47,537,935
Total Customer Charge Costs	**73,625,968**
Residential Bills (annual)	13,278,972
Monthly Customer Charge	**$ 5.54**

Develop Fixed Charge Rate	
Pre Tax Rate of Return	9.15%
Depreciation	5.0%
Fixed Charge Rate	14.2%

Residential Customer Charge
Gas Utility

Invested Capital

Res Meters, Services, Regulators		689,022,480
Accumulated Depreciation		193,646,765
Net Plant		495,375,716
ADFIT		-124,621,800
Customer Deposits		-9,034,349
Rate Base		361,719,566
Times Fixed Charge		$51,183,319

O&M Expense

Res Meters-Operations		5,615,901
Res Meters,Services Maint.		2,805,675
Customer Accounting A901-903		18,649,794
Related Pension & Benefits		3,959,450
Total Expense	$	31,030,820
Total Customer Charge Costs	**$**	**82,214,138**
Residential Bills (annual)		7,578,780
Monthly Customer Charge	**$**	**10.85**

Develop Fixed Charge Rate

Pre Tax Rate of Return	9.15%
Depreciation	5.0%
Fixed Charge Rate	14.2%

Example of Customer Charge
Impact on Energy Efficiency Purchase

Assumptions

Location: Baltimore
Air Conditioner Size: 3 ton
Energy Star SEER: 18
Conventional unit SEER: 13
Initial Cost- $4,400 vs. $3,342
Real Discount Rate: 2%

kWh Rate Inputs
With Current Cust Charge: $0.111
With $10.00 Cust Charge: $0.109
With $16.13 Cust Charge: $0.1045

Net Life Cycle Benefit:
With Current Customer Charge: $32
BGE Requested Customer Charge: $8
BGE CCOS Customer Charge: ($35)

NPV Operating Cost Savings
Current Cust Charge: $1,090
Requested Customer Charge: $1,066
CCOS Customer Charge: $1,023

Payback Period (Years):
Current Cust Charge: 11.7 years
Requested Customer Charge: 12 years
CCOS Customer Charge: 12.5 years

Percentage *Reduction* in Savings
Vs. Current Customer Charge

Net Life Cycle Benefit
Requested Customer Charge: 75%
BGE CCOS Customer Charge: 109%

Payback Period:
Proposed Customer Charge: 3% longer
BGE CCOS Customer Charge: 7% longer

Note: Net Life Cycle Savings = PV of Operating Cost Savings Minus Additional Initial Cost of Energy Star Equipment