Austin Energy’s Tariff Package:

2015 Cost of Service Study

and Proposal to Change Base Electric Rates

January 25, 2016

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AUSTIN ENERGY'S TARIFF PACKAGE

1. INTRODUCTION

Austin Energy (AE), the municipally owned electric utility of the City of Austin, files this Update to its Cost of Service Study and Proposal to Change Base Electric Rates (Tariff Package). This Tariff Package includes the Rates Recommendation Report to the Austin City Council (City Council), the Cost of Service Schedules and Work Papers, Schedule of Rates, and associated appendices. The goal of the Tariff Package is to inform the public and the City Council about Austin Energy's current financial situation and explain the data, calculations, and rationale used to develop the proposed base rates.

1.1. NEED FOR COST OF SERVICE STUDY AND RATE REVIEW

Previously adopted City Council ordinances require AE to review its rates and update its cost of service study at least once every five years.[1] While City Council adjusted AE's base electric rates in June 2012, those adjustments were made based on data from a historical test year of 2009. As five years have passed since that test year, AE has updated its cost of service study using a historical test year of 2014 to determine its new revenue requirement.

1.2. SUMMARY OF MAJOR FINDINGS OF COST OF SERVICE STUDY

Austin Energy's Tariff Package compares the revenue requirement needed to satisfy AE's financial obligations incurred in the historical test year ending September 30, 2014 with the revenue generated by the rates that were previously set using the historical test year ending September 30, 2009. Austin Energy then calculated the difference between these two balances to determine the staff-proposed changes in AE's base rates.

[1] *See*, City of Austin Ordinance No. 20120607-055, Part 12, (June 7, 2012). *See also*, City of Austin Fiscal Year 2015-2016 Approved Budget, Austin Energy Financial Policy No. 17, (Sept. 10, 2015), Vol. II, pg. 783.

For Test Year (TY) 2014, the adjusted revenue requirement is $1,217,227,310. This revenue requirement is 1.4 percent less than the revenue that would be generated by the current base rates. Based on this reduced revenue requirement, Austin Energy is proposing changes to its base rates.

Additionally, the results of the cost of service study suggest a change to the current rate class structure is warranted. Specifically, AE proposes changing its qualification for the Secondary Voltage 2 and 3 customer classes. The Secondary Voltage 2 class is proposed to include customers whose peak demand ranges from 10 kilowatts (kW) to less than 300 kW. AE's Secondary Voltage 3 class would then consist of customers whose peak demand is equal to or greater than 300 kW.

1.3. TREATMENT OF CONFIDENTIAL INFORMATION

As a public power entity, Austin Energy is governed by the Texas Public Information Act and treats most information it maintains as public in nature. As a result, AE will release nearly all of its corporate and operating information in this Tariff Package and in response to requests submitted during the Impartial Hearing Examiner process.

However, Section 552.133 of the Texas Government Code exempts certain competitive information from release under the Public Information Act.[2] In addition, in 2011, in accordance with state law, the City Council passed an ordinance that specifically exempts certain types of Austin Energy-related information from release.[3] Moreover, these laws authorize AE to protect competitively sensitive information, such as generator unit cost data. Release of this type of data would give advantage to Austin Energy's competitors in the wholesale electric market. Finally, pursuant to state and local law, Austin Energy does not normally release confidential customer information without the express permission of the impacted customer.

1.4. NOTICE AND PROCESSING

Pursuant to the rules established for this rate review process, AE provided written notice of its intent to change rates to its customers throughout January. Specifically, AE published a Notice of Intent to Change Rates in its monthly newsletter, PowerPlus, which is distributed to all AE customers as a utility bill insert. A copy of this notice is provided as Exhibit A. This month, AE is running a Notice of Intent to Change Rates once a week for 4 weeks in the *Austin-American Statesman*, *Ahora Sí*, and *The Villager*.

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[2] *See*, Public Information Act, Government Code §552.133.

[3] *See*, City of Austin Resolution 20110310-003, (March 10, 2011).

The text of the newspaper notice is provided as Exhibit B. Finally, AE has presented or will present proposed changes to its revenue requirement, cost of service, and rate design over two separate meetings of the Electric Utility Commission (EUC) and over two separate meetings of the City Council.[4]

1.5. DEADLINES AND NEXT STEPS

With the filing of this Tariff Package, individuals and entities interested in participating in the Impartial Hearing Examiner (IHE) rate review process will have 30 calendar days to file a motion to intervene. However, since the thirtieth day after the filing of the Tariff Package falls on Sunday February 21, 2016, the deadline to file a Motion to Intervene will be February 22, 2016. Included with the motion, individuals and companies should detail which issues should be discussed before the Impartial Hearing Examiner.

On January 25, 2016, AE will present this Tariff Package to the City Council. No later than five business days following this presentation, AE will issue a non-exclusive list of topics to be addressed by the Impartial Hearing Examiner (Statement of Issues). The Statement of Issues is not intended to be an exhaustive list. Rather, the Statement of Issues will articulate the essential issues on which the Impartial Hearing Examiner must deliberate and develop a recommendation for the City Council to consider. Other topics may be addressed at the discretion of the Impartial Hearing Examiner.

Additional procedural steps will be determined by the Impartial Hearing Examiner and distributed to Parties to this process via electronic service and posted to the Rate Review website maintained by the Office of the City Clerk of the City of Austin. Pleadings or questions about the process should be emailed to rate.review@austinenergy.com or delivered in-person in hard copy to the Office of the City Clerk at 301 West 2nd Street, Austin, Texas on the first floor. Mailed hard copies will not be accepted.

In order to meet internal and administrative timelines, AE requests a final decision on its proposed rate design from the City Council no later than June 30, 2016.

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[4] One presentation to the Electric Utility Commission was made on December 14, 2015 and the second will be delivered on January 25, 2016. One presentation to the City Council was made on December 15, 2015 and the second will be made on January 25, 2016.

1.6. AUTHORIZED REPRESENTATIVES

For purposes of the rate proceeding before the Impartial Hearing Examiner, Austin Energy's authorized representatives are:

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Andrea Rose
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andrea.rose@austintexas.gov

All pleadings, motions, orders, and other documents filed in this proceeding should be served upon Ms. Rose at andrea.rose@austintexas.gov.

Respectfully submitted,

Andrea D. Rose

(Signature of Authorized Representative)

ANDREA D. ROSE

(Printed Name of Authorized Representative)

24081615

(State Bar Number)

1/25/16

(Date Submitted)

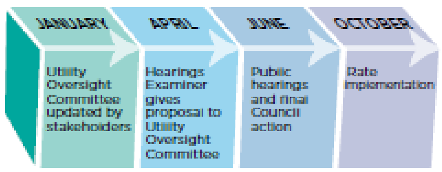
1.7. EXHIBIT A

NOTICE OF INTENT TO CHANGE RATES:

POWERPLUS

Austin Energy's Upcoming Rate Review

As per City of Austin policy, Austin Energy is reviewing how much it costs to provide electric services to its almost 450,000 customers. This cost of service study is based on the actual expenses incurred by the utility in 2014. Current rates are based on 2009 expenses and becoming out-of-date. With this new information, Austin Energy will propose changes to its base electric rates so that they accurately reflect the utility's current operating environment. This will ensure Austin Energy can sustainably serve its growing community.



Austin Energy has four basic goals for the cost of service study and rate review. This process will:

- Be fair and transparent
- Adhere to policies and laws adopted by the City and the state
- Reflect the community's values as they relate to the environment, affordability and customer service
- Maintain the financial integrity of the utility.

At the end of January, Austin Energy will present the updated cost of service study and Austin Energy's recommended changes to base rate design to the Austin City Council's Utility Oversight Committee. Formal deliberations about the proposed changes will occur from February through April. The City Council is tentatively scheduled to consider a final proposal in May and June.

Customers and community members can learn more about the rate review process by visiting austinenergy.com/rates. Interested parties can participate in the formal deliberations by filing a Motion to Intervene with the City Clerk's office. Filing instructions and the complete public record of the deliberations can be found by visiting **austintexas.gov/department/city-clerk.**

Para una Traducción en Español:
Si gusta recibir este folleto en español, llame a Austin Energy al **512-972-9523.**

1.8. EXHIBIT B

NOTICE OF INTENT TO CHANGE RATES:

NEWSPAPER NOTICES[5]

AUSTIN ENERGY'S NOTICE OF INTENT TO CHANGE RATES

Austin Energy has finished reviewing how much it costs to provide electric services to its approximately 450,000 customers. Based on this cost of service study, Austin Energy will propose changes to its base electric rates so that the rates accurately reflect the utility's current operating environment. At the end of January 2016, the cost of service study and proposed new rates will be presented to the Austin City Council's Austin Energy Utility Oversight Committee.

To help the public increase its involvement in the rate-making process, the City has hired an Impartial Hearing Examiner ("IHE") who will conduct a hearing on Austin Energy's proposal. The IHE will help the City Council's decision-making process by organizing the opinions and evidence presented by Austin Energy and any of its customers that want to offer their input. Then, the IHE will prepare a formal recommendation to the City Council about how best to proceed with the rate proposal. The City Council has the final authority to set retail rates.

To participate in the formal IHE process, you must (1) be an Austin Energy customer, (2) have access to an email account to which documents can be sent to you, and (3) file a motion to intervene.

Persons who wish to intervene in or comment upon these proceedings should notify the IHE as soon as possible, as an intervention deadline will be imposed.

More information, including a copy of the procedural rules and how to file a motion to intervene, is available at **rates.austinenergy.com** or at **http://www.austintexas.gov/department/city-clerk**. Interested persons may also review Austin Energy's Tariff Package, once it is formally released, on these two websites.

[5] This ad was translated into Spanish for publication in *Ahora Sí*.

2. OVERVIEW OF RATES REPORT TO COUNCIL

The following Rates Report to Council describes in detail the results of Austin Energy's 2015 Cost of Service (COS) study, changes in the utility's revenue requirement, and adjustments to the allocation of costs among groups of customers. This report also explains Austin Energy's proposed changes to base electric rates. The report is organized in the following manner:

- Chapter 2 outlines the policies that guided the Cost of Service study and development of revised base electric rates;
- Chapter 3 offers an in-depth examination of AE's operating environment and business practices, providing a fundamental context in which critical business decisions can be made;
- Chapter 4 illustrates the changes in AE's revenue requirement based on a historical test year of 2014;
- Chapter 5 describes the changes in cost allocation methodologies and outcomes; and
- Chapter 6 provides AE's recommended changes to base electric rates, founded on the results of the Cost of Service study, state law, and local community priorities.

Attached to the report are the full results of the Cost of Service study update and several appendices that guided Austin Energy staff in the formation of these recommendations.

The Cost of Service study and associated recommendations have been under development by Austin Energy and its consultants since summer 2015. This Rates Report to Council presents to the public, and to the City Council, Austin Energy's analysis and recommendations. Its release is the first step in the public review process.

The following sections of this chapter outline important procedural and policy guidance that helped shape and inform Austin Energy's decision-making process. They also provide an overview of key results of the Cost of Service study update and proposed changes to base electric rates.

2.1. COST OF SERVICE AND RATE-MAKING PROCESS ADOPTED FOR THIS PROCEEDING

The current rate review process is highly informed by Austin Energy's experiences with the 2012 rate review, the Austin community's first intensive, in depth exploration of rates in more than 18 years. The following sections outline that previous review process and describe the steps and rationale of the 2016 review.

2.1.1. Austin Energy's Recent Rate History

In late 2010, Austin Energy embarked on an extended rate review process, seeking to engage members of the public about utility policies and fundamentals of ratemaking.

Following an extensive deliberative process, Austin Energy staff prepared its rates recommendations for formal review by the City Council, presenting its Rates Analysis and Recommendations Report to the EUC in September 2011. The EUC held a series of five public hearings to consider the proposed Cost of Service; the proposed revenue requirements, including customer classes, cost allocation methodologies, rate structures, and rates; and alternative methods used in the utility industry for the allocation of power production costs among customer classes. Each meeting included an opportunity for members of the public to address the EUC. Meetings were recorded and later broadcast. The EUC offered aligned parties an opportunity to appear in panels for formal presentations. Thirty-three speakers participated in these panel presentations.

The EUC phase of the process concluded with the consideration of a Decision Point List (DPL) containing 27 individual items. The members of the EUC voted on each item on the DPL. The final DPL — which included the EUC's recommendation on each item, as well as the positions and individual comments of members of the EUC, the Residential Rate Advisor, and interested members of the public — was forwarded to the City Council on October 31, 2011.

Austin Energy provided its final recommendations to the City Council on December 19, 2011, which were addressed in three public hearings, numerous City Council briefings, and followed by 12 formal work sessions. The recommendations were reviewed by a consumer advocate hired at the direction of the City Council, who provided written input to the City Council and appeared at City Council work sessions. The City Council ultimately approved the rate ordinance on June 7, 2012.

Following City Council's adoption of the rate ordinance, a coalition of citizens calling themselves Homeowners United for Rate Fairness (HURF) collected sufficient signatures from Austin Energy-served households located outside of Austin's City limits to proceed with a rate appeal at the Public Utility Commission of Texas (PUCT).[6] That appeal resulted in a settlement among the City of Austin, HURF and all other parties. Under that settlement, Austin Energy reduced the rate increase to customers outside the Austin City limits by approximately $5 million annually and adjusted the rate tiers for outside residential customers, but otherwise retained the rates and rate structure adopted by the City Council.

[6] *See*, *Petition by Homeowners United for Rate Fairness to Review Austin Rate Ordinance 20120607-055*, PUCT Docket No. 40627.

2.1.2. Steps in the Current Rate Review Process

The City Council-adopted 2012 rate ordinance included guidance for handling future revisions of Austin Energy's rates. Specifically, City Council directed that:

- Austin Energy's rates should be reviewed at least once every five years;
- The City will hire a consumer advocate who is knowledgeable and experienced in ratemaking issues to represent residential and small business consumers; and
- The City may also hire an impartial hearing examiner to conduct the review and make recommendations.[7]

To ensure Austin Energy met City Council's first directive, AE launched a new rate review process in 2015 and initiated a new Cost of Service study using financial information from FY 2014.[8] Austin Energy staff briefed the Austin Energy Utility Oversight Committee in June 2015 on Austin Energy's proposed plan and process for the City's review of Austin Energy's rates.

Next, Austin Energy brought to City Council for approval on October 15, 2015 the selection of an IHE. The IHE will oversee the fact finding process, organize issues for City Council consideration, and make recommendations to the City Council on those issues.

Austin Energy continues to work with the City Council to select a qualified Independent Consumer Advocate, an expert who will represent the interests of a substantial number of Austin Energy's residential and small commercial customers. Austin Energy will provide information to the Independent Consumer Advocate regarding Austin Energy's data, costs, analyses, and recommendations.

Concurrent with these City Council-related efforts, Austin Energy also developed a thorough public input process through which stakeholders and customers can offer suggestions about the outcomes of the Cost of Service study and opinions on proposed rate changes. The three-part process includes ongoing dialogue with the EUC, participation in the IHE review process, and City Council's review and decision-making process.

Throughout the entire rate review, the EUC's role is to provide a forum for members of the public to share their input, especially for those individuals or groups unable to participate in the more formal IHE process. The Commission may synthesize the information provided by the public and relay

[7] City of Austin Ordinance No. 20120607-055, Part 12.

[8] The 2012 rate review used financial information from FY 2009; thus, Austin Energy staff determined that a cost of service update using FY 2014 data was required.

suggestions and recommendations to the City Council and Austin Energy. In addition, the EUC will be asked to provide formal recommendations to the City Council on issues to be deliberated during the IHE process, on the IHE's recommendation to City Council, and on City Council's proposed rate ordinance.

The second prong of the public rate review is the formal IHE process. The Impartial Hearing Examiner, operating under strict *ex parte* rules,[9] will conduct a process that includes:

- Admission of parties/participants;
- Alignment of parties;
- Discovery;
- Submission of responses to staff's Rates Report to Council;
- Formal hearings, including presentations of witnesses or witness panels; and
- Submission of briefs.

At the conclusion of the process, the IHE will structure the material presented throughout the proceeding into a formal recommendation for City Council consideration. The IHE's recommendation will organize the issues on which a decision is required by presenting the arguments supporting different perspectives; assessing the issues based on the merits of the argument, state law, and local policy; and, offering formal recommendations for the City Council to consider. AE expects the IHE's report to be issued at the beginning of May 2016.

In the final phase of the public review process, Austin Energy staff anticipate that the City Council will deliberate on Austin Energy's and the IHE's recommendations in three working sessions of the Utility Oversight Committee and in two public hearings conducted by the City Council. Austin Energy recommends that at least one of the public hearings before the City Council be conducted outside of Austin City limits. The staff anticipate a final City Council decision by the end of June, which will allow for any adopted rate adjustments to be incorporated into the City budget process.

As of the middle of January 2016, Austin Energy has presented the revenue requirement and initial Cost of Service analysis at the December 2015 meetings of the EUC and the Utility Oversight Committee. Next, AE will present its final Cost of Service analysis and proposed changes to base electric

[9] Under *ex parte* rules, the IHE may not have any substantive conversation about the issues being deliberated in the IHE review process outside of a meeting open to all participants in the process. Participants must be notified in advance of the meeting and must be provided an opportunity to participate in the conversation. In this case, participants to the process include AE staff, members of the EUC, the City Council members and their staff, and other interested parties outside the City's governing structure.

rates at the January 2016 meetings of the EUC and the Utility Oversight Committee. The formal IHE review process will launch following these presentations.

2.2. POLICY OBJECTIVES OF AUSTIN ENERGY'S RATES

Austin Energy sets its electric rates based upon a foundation of long-standing principles and in accordance with state and local laws and policies. Austin Energy articulated its rates philosophy in a white paper presented to the Public Involvement Committee in 2011. That paper is included as Appendix B. As explained in the white paper, Austin Energy developed a set of rate principles aligned with the strategic objectives discussed in Section 2.2.1. These following principles are just as relevant today as when first discussed in 2011:

1. Ratemaking should be founded on economic standards common to the electric utility industry.
2. Rates should be fair between customer classes.
3. Rates should ensure the long-run financial strength of the utility.
4. Rate structures should provide incentives for energy conservation, promote efficient use of resources, and encourage consumer investment in energy efficiency.
5. Rates should maintain the affordability of electricity.
6. Rates should provide a discount to low-income customers.
7. Rates should be as simple and understandable as practical.
8. The rate review process should be transparent, including public involvement.
9. The rate review process must adhere to laws and regulations.

These principles emphasize that Austin Energy's rates should be based on strong economic and legal principles, incorporate balance among objectives, and ultimately must be in alignment with Austin Energy's strategic direction.

The current rates and rate structure fulfill these guiding principles. Therefore, significant substantive changes to the overall rate design are not required. In this particular rate review process, Austin Energy is emphasizing several key principles, which were presented to the City Council's Utility Oversight Committee in June 2015, including:

- Adherence to applicable laws and regulations;

- Transparency of the process with robust public involvement;
- Affordability for customers of all types;
- Fairness; and
- Maintaining financial integrity of the utility and thus the City of Austin.

Ultimately, the Cost of Service update and rate design must be legal, reflect community priorities as determined by City Council policy, and keep the utility on sound financial ground. Therefore, the rate setting process must be fair, inclusive, transparent, and well-organized.

2.2.1. Council Policy Framework

Both the recommendations contained within this report and the corresponding rate review process are guided and informed by the policy framework established by City Council for Austin Energy. That framework is outlined in a variety of sources, including the 2003 Strategic Plan. That plan established a series of strategic objectives to help Austin Energy prepare for the future by reducing financial risk, providing excellent customer service, and acknowledging environmental issues and the need for energy efficiency and renewable energy programs. Other sources of the City Council's policy framework include the 2007 Austin Climate Protection Plan; the Austin Energy Resource, Generation and Climate Protection Plan to 2025: An Update of the 2020 Plan; and the affordability goals adopted for Austin Energy by City Council on February 17, 2011.

By synthesizing the objectives from each of these sources, the City Council's policy framework for Austin Energy can be summarized as follows:

- Risk Management:
  - Maintain financial integrity and achieve a AA bond rating
  - Transition away from CO_2 emissions, including reduce CO_2 emissions by 20 percent below 2005 level by 2020
  - Net zero community-wide greenhouse gas emissions by 2050

- Excellent Customer Service:
  - Provide exceptional system reliability
  - Improve customer satisfaction
  - Improve employee satisfaction
  - Create and sustain economic development

- Energy Resources by 2025:
  - 900 MW of Demand Side Management by 2025, including 100 MW of demand response
  - 55 percent of energy from renewable resources by 2025
  - 950 MW of solar capacity by 2025, including 200 MW of local solar

- Affordability:
  - Limit rate adjustments to no more than 2 percent annually
  - Remain in the lower 50 percent of retail rates across the State

2.2.2. Key Components of Austin Energy's Rate Structure

Austin Energy's rate structure is built on a set of rate principles, consistent with the overarching policy framework outlined above. The most fundamental components of the resulting rate structure are described below.

2.2.2.1. Rate Incentives to Achieve Energy Efficiency Goals

As approved by the City Council, Austin Energy has aggressive goals for achieving energy efficiency objectives. The rate structure complements and promotes these energy efficiency objectives. Specific provisions designed in accordance with those goals are tiered residential rates, winter/summer rate differentials, and demand charges extended to most commercial customers.

2.2.2.2. Unbundled Charges

Several components of Austin Energy's rates are unbundled from the base rate. These charges are the Regulatory Charge and the Community Benefits Charge. The Regulatory Charge recovers the costs of the administrative fees from the Electric Reliability Council of Texas (ERCOT), Austin Energy's use of the ERCOT-wide transmission grid, and fees assessed by the Texas Reliability Entity and the North American Electric Reliability Corporation. The Community Benefits Charge includes three components: Energy Efficiency Services, Service Area Street Lighting, and the Customer Assistance Program (CAP). In each case, these charges recover costs of specific programs or expenses, and are passed through dollar-for-dollar to customers with no mark up. By separating out these charges individually, customers have greater transparency into the components of their bill and Austin Energy has the opportunity to adjust these charges annually through the City budget development process.

2.2.2.3. Power Supply Adjustment

The Power Supply Adjustment (PSA) is a dollar-for-dollar pass through of certain power supply costs, which include the net costs of ERCOT settlement (*i.e.*, net wholesale supply costs), and the costs of purchased power agreements, fuel, transportation, and market risk mitigation. The Power Supply Adjustment can be adjusted at least annually by action of the City Council to assure improved cost recovery.[10]

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[10] Austin Energy's rates previously included a Fuel Adjustment Clause. Traditionally, a Fuel Adjustment was included in rates to allow a utility to adjust to the often volatile costs of fuel procurement. Over time, the

2.2.2.4. <u>Rate Class Structure</u>

Austin Energy's rate schedule now includes twelve customer classes, one for Residential, nine for commercial (three secondary, four primary, and two transmission), and two for commercial lighting. In the interim since the City Council adopted the 2012 rate ordinance, the City Council added two additional classes for large commercial/industrial customers transitioning from the Large Primary Service Special Contract Industrial Rider, which expired — with some exceptions — in May 2015.

2.2.2.5. <u>Customer Discounts</u>

Austin Energy provides rate modifications to two sets of non-residential customers, Independent School Districts and group worship facilities (or House of Worship accounts (HOWs)). Independent School Districts receive a 10 percent discount off of the monthly electric bill. Group worship facilities are subject to a rate cap. In each case, the amount of the discount is recovered from the other customers served in the rate class of the customer account receiving the discount. Austin Energy is proposing certain modifications to these discounts during the current rate review process.

2.2.2.6. <u>Low-income Residential Customer Discounts and Benefits</u>

Austin Energy offers qualifying low-income customers benefits through the Customer Assistance Program. CAP provides discounted rates, targeted energy efficiency programs, and bill payment assistance for these qualifying residential customers. The bill discount includes a waiver of the customer charge, waiver of CAP component of the Community Benefits Charge, and a 10 percent discount on the remaining bill. Funding for CAP is recovered through the Community Benefits Charge.

2.2.2.7. <u>Inside-Outside Rate Differential</u>

Under the settlement of the rate appeal adopted by the City Council in 2013, some customer classes outside the City limits of Austin receive lower rates and reduced charges.

2.3. <u>REVENUE REQUIREMENT OVERVIEW</u>

The analysis conducted by AE staff shows that Austin Energy's revenue requirement, based on a 2014 test year with certain known and measureable adjustments, is $1.217 billion, an increase of

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components included in the Fuel Adjustment expanded to include purchased power agreements, ancillary services, fuel price mitigation expenses, and ERCOT wholesale market expenses. In particular, the adoption in 2010 of the ERCOT Nodal Market fundamentally changed the way that Austin Energy transacts for power and how Austin Energy passes through those costs to customers. Austin Energy converted from the Fuel Adjustment Clause to the Power Supply Adjustment in recognition of the dramatic changes in the marketplace that drive the often volatile costs of supplying power to customers.

approximately $95 million over the revenue requirement approved by City Council in the 2012 rate ordinance. The base rate revenue requirement is $614.4 million. The difference between the revenue requirement and the base rate revenue requirement is the projected costs of the pass-through charges (Power Supply Adjustment, Regulatory Charge, and Community Benefits Charge), which are not included in base rates. Though the total revenue requirement has increased by approximately $95 million, AE's current rate structure would collect $17.5 million more than the revenue required to meet TY 2014 costs.[11]

The components of the revenue requirement are shown in Figure 2.1 and discussed further in Chapter 4. The first column, labeled "Item," describes the major cost components of utility operations. The second column, labeled "FY 2014," shows the revenue required to meet expenses cost components ($1.275 billion) and the amount of revenue that would be collected under current rates ($1.246 billion) considering normalized fiscal year 2014 billing data. Information in the third column, labeled "Adjustments," shows changes made to the revenue requirement for known and measureable adjustments. These adjustments reduce the 2014 revenue requirement by $57.7 million, primarily attributable to decreased debt service and lower power supply costs.[12] The last column, labeled "TY 2014," shows the adjusted revenue requirement to meet the adjusted cost components ($1.217 billion) and the amount of revenue that would be collected under current rates ($1.235 billion) considering normalized fiscal year 2014 billing data. This last column shows an over-recovery for the TY 2014.

[11] Revenue requirement of $1,217,227,310 less Test Year revenue of $1,234,701,609 equals -$17,474,299, representing excess revenue to be returned to customers in reduced rates.

[12] *See* Section 4.3 Test Year Adjustments for further discussion.

Figure 2.1
Test Year 2014 Revenue Requirement

Item	FY 2014	Adjustments	TY 2014
Operation & Maintenance Expenses			
Production	$ 630,722,669	$ (18,295,231)	$ 612,427,438
Transmission	121,459,831	9,268,156	130,727,986
Distribution	56,823,106	3,384,207	60,207,313
Customer	86,827,033	(26,886,288)	59,940,745
A&G	139,890,673	853,777	140,744,450
Total Expenses	$ 1,035,723,311	$ (31,675,379)	$ 1,004,047,932
Depreciation & Amortization	$ 147,302,442	$ (6,798,240)	$ 140,504,202
Margin	159,331,551	(15,396,547)	143,935,003
Other Expenses	40,888,095	(30,445,334)	10,442,761
Other Non-Rate Revenue	(108,277,160)	26,574,571	(81,702,589)
Total Revenue Requirement	**$ 1,274,968,239**	**$ (57,740,929)**	**$ 1,217,227,310**
Test Year Rate Revenue	$ 1,246,153,540		$ 1,234,701,609
(Excess)/Deficiency	$ 28,814,698		$ (17,474,299)
(Excess)/Deficiency	2.3%		(1.4%)

With the test year rate revenues estimated at $1.235 billion, Austin Energy proposes a general, system-wide rate reduction of $17.5 million, or 1.4 percent.[13] At this level, the proposed revenue requirement will sustain the overall financial health of Austin Energy while putting Austin Energy's rates on a trajectory to comply with the City Council's goals for affordability. However, the proposed revenue reduction is a small percentage of Austin Energy's overall operations and the utility's ability to sustain reduced rates into the long term future will depend upon many factors, several of which are outside the utility's control, including unpredictable weather events, electric market conditions in ERCOT, the pace of growth of electric sales, and the state of the general economy. Additionally, changes in economic forecasts or in the pace of Austin Energy's capital investments could impact the overall revenue requirement in the future.

2.4. COST ALLOCATION OVERVIEW

In the current cost of service assessment, Austin Energy has allocated costs to customer classes using different allocation methods for different categories of costs. For each of those categories, the

[13] Please see Section 2.6 of this chapter as well as Chapter 6 for treatment of how the base revenue reduction will be spread among customer classes.

Cost of Service analysis applies the methodology approved by the City Council in 2012, with the exception of the allocator of generation production costs. For these specific costs, Austin Energy recommends using the ERCOT Twelve Coincident Peak (ERCOT 12CP) methodology. This is an appropriate methodology for a regulated entity like Austin Energy that operates in a centralized dispatched environment like the ERCOT Nodal Market.

Costs allocated by customer class are shown in Figure 2.2. In the first numeric column, the figure identifies the share of the total revenue requirement allocated to each customer class. The second numeric column presents the projected revenues under current rates from each customer class. The difference between these columns is the excess or deficit for each class relative to cost of service. The final column shows the percentage adjustment — either up or down — required to bring that class to cost of service.

Figure 2.2
Existing Base Rate Changes Needed to Meet Total Cost of Service by Customer Class

Customer Class	Total Cost of Service[(1)] ($)	Existing Base Rates and Test Year Pass-Through Rates[(1)] ($)	Excess/ (Deficient) Revenue[(2)] ($)	Increase/ (Decrease) Needed to Meet Cost of Service (%)
Residential	527,473,323	474,062,283	(53,411,041)	11.3
Secondary Voltage <10 kW	32,241,755	31,458,282	(783,472)	2.5
Secondary Voltage 10 - <300 kW	241,019,337	283,339,669	42,320,332	(14.9)
Secondary Voltage ≥300 kW	220,057,525	238,491,828	18,434,303	(7.7)
Primary Voltage <3 MW	42,224,997	46,257,714	4,032,717	(8.7)
Primary Voltage 3 - <20 MW	47,471,430	52,185,478	4,714,048	(9.0)
Primary Voltage ≥20 MW	87,271,333	89,945,727	2,674,394	(3.0)
Transmission Voltage	1,317,596	2,146,390	828,794	(38.6)
Transmission Voltage ≥ 20 MW @ 85% aLF	13,863,814	13,517,421	(346,394)	2.6
Service Area Street Lighting	N/A	N/A	N/A	N/A
City-Owned Private Outdoor Lighting	3,776,457	2,884,834	(891,623)	30.9
Customer Owned Non-Metered Lighting	114,954	108,555	(6,399)	5.9
Customer Owned Metered Lighting	394,788	303,428	(91,360)	30.1
Total	**1,217,227,310**	**1,234,701,609**	**17,474,299**	**(1.4)**

Notes:

1) Excludes Customer Assistance Program funding.

2) Only shows base revenue differences and none of the impacts of pass-through charges.

The table demonstrates that the Residential customer class is well below cost of service, by $53.4 million (11.3 percent), while certain non-commercial customer classes are above cost of service. The greatest differential in dollar terms is for the Secondary Voltage class from 10 to 300 kW, at $42.3 million above cost of service. Chapter 5, Cost of Service, discusses the cost allocation methodologies used to assign costs to specific classes of customers and also includes Austin Energy's proposal for allocating the $17.5 million in excess revenues across the customer classes.

2.5. RATES AND RATE DESIGN OVERVIEW

The current rate structure is sound, is built on a foundation of laws and ratemaking principles, and serves the community well. Accordingly, in this proceeding Austin Energy recommends maintaining the vast majority of the base rate structure currently in place. Nevertheless, some components of the rate structure merit re-examination when considering staff's experience since adoption of the rates in 2012, feedback from members of the community, studies conducted by Austin Energy in the interim,[14] and improvements in the research and Cost of Service data available to Austin Energy. Each of these is discussed in this Rates Report to Council.

As noted above, the cost allocation demonstrates that certain customer classes are experiencing significant deviations from cost of service. Because the size of that deviation is large for some customer classes, moving all customer classes immediately to cost of service would result in a financial burden for certain customers in classes with an indicated large rate increase. The associated rate shock of such a dramatic change would place undue hardship on the customers in these classes and would be undesirable. Instead, good utility rate design practice and City Council policy suggest that a more gradual approach to achieving full cost of service across all customer classes remains an appropriate direction for Austin Energy to pursue. This gradual approach can move customer classes closer to the cost of service in small steps over several years. Therefore, Austin Energy proposes that in the first year of the proposed rate change, beginning in October 2016, the $17.5 million in excess revenues be used to reduce non-Residential customer classes that are currently above cost of service. In the first year, Austin Energy proposes to maintain the current Residential class revenues with no overall increase in rates.

Looking beyond year one, there are many rate-making considerations related to moving all customer classes closer to cost of service. These considerations include: altering the number of years over which changes can be made, modifying the number of incremental steps necessary to move closer to cost of service, adjusting the steepness of the five Residential tiers, reducing the number of Residential tiers, and changing the magnitude of the customer charge. These possible adjustments will certainly be issues for discussion in the proceeding before the Impartial Hearings Examiner.

2.5.1. Proposed Changes to Rate Design

Austin Energy recommends a number of incremental adjustments to the rate design for its retail electric customers. The proposed changes are rooted in the ratemaking principles outlined above,

[14] NewGen Strategies & Solutions, *Small Commercial Customer Demand Charge Study*, March 19, 2015; *Summary of Austin Energy's Reserve Funds, Final Report*, July 27, 2015.

gradually move customers classes closer to full cost of service, mitigate some of the inherent risk in revenue collection associated with the current rate structure, and maintain a strong emphasis on community priorities, like energy efficiency and support for the financially vulnerable. The details of the proposed changes are discussed in detail in Chapter 6, Rate Design Modifications.

2.5.1.1. Eliminate Seasonal Base Rate Differential

Austin Energy finds that the underlying cost drivers of the base rate and the Regulatory Charge do not vary with the season. As well, with the significant differential between the current summer rates and the non-summer rates, certain customers may be challenged to manage monthly bills. Austin Energy proposes to eliminate the summer/non-summer rate differential within the base rates.

2.5.1.2. Create Seasonal Adjustment for PSA

Notwithstanding the recommendation to eliminate seasonal base rates, Austin Energy does find that certain underlying cost drivers of the Power Supply Adjustment do vary with the season. Thus, it is reasonable to consider a seasonal variation for the PSA. Varying the PSA seasonally will improve timely cost recovery of power supply costs and help maintain pricing incentives consistent with the City Council's goals for energy efficiency.

2.5.1.3. Residential Tier Adjustment

Austin Energy proposes to modify the five rate tiers for Residential customers by raising the rate of the bottom tier and reducing the rate of the top tier, along with some refinements to the middle tiers. Revenue collection in the lowest rate tier, currently at 1.8 cents per kilowatt hour (kWh) in the non-summer period and 3.3 cents per kWh in the summer period, is unaligned with consumption in this tier: 47.3 percent of Austin Energy's residential base usage occurs in Tier 1 while only 21.6 percent of revenue associated with the tiered charges occurs in Tier 1. Significant usage in the upper tiers must occur to offset the under-collections in the first tier. New residential construction in Austin Energy's territory has trended toward a higher concentration of multi-family housing and as average residential energy use across the system appears to be in a sustained decline[15] — at least in part due to the success of energy efficiency programs — under-recovery in the lower rate tiers is anticipated to be a growing concern. In the event of low residential usage, as in the summer of 2007 when temperatures were unusually moderate, Austin Energy could significantly under collect base revenue. Moderating the tiers

[15] Form 861 data from the federal Energy Information Administration shows average residential use by customers of Austin Energy in 2014 at 903 kilowatt hours per month, a drop from 918 in 2013, and well below the State average of 1,130 kilowatt hours per month.

somewhat will ensure greater revenue stability. Additionally moving these subsections of the Residential class closer to cost of service represents a continuing emphasis on the fairness of the overall rate design in the utility's attempt to balance policy priorities with intra- and inter-class subsidies.

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

2.5.1.4. Adjustment to the Secondary Commercial Rate Classes

Based on analysis of the secondary voltage customer classes, Austin Energy proposes to adjust the boundaries of the secondary voltage customer classes. The proposed customer classes are:

- Secondary Voltage Service 1 (S1) — from 0 to less than 10 kW;
- Secondary Voltage Service 2 (S2) — from 10 to less than 300 kW; and
- Secondary Voltage Service 3 (S3) — 300 kW or more.

This alignment of classes expands the current S2 class from an upper bound of 50 kW to an upper bound of 300 kW, based on the consistent usage characteristics among these customers. Austin Energy considered adjustments to the upper boundary of the S1 class, but concluded that, based on a class break point analysis, an adjustment is not warranted. As discussed with the EUC and the City Council, Austin Energy studied in great detail the rates charged the smallest customers in the S2 class. In addition, Austin Energy's consultant, NewGen Strategies & Solutions, completed two in-depth examinations of secondary class assignment and the appropriateness of the use of demand charges.

In accordance with the results of this intensive study, AE proposes several adjustments to address concerns related to small S2 customers. These adjustments include classifying commercial customers into rate classes annually based on their peak usage averaged over the four summer months rather than based on their one time summer peak. The City Council approved this policy change during the budget discussion in 2015, and it is maintained in this Cost of Service study. In addition, Austin Energy staff proposes modifications to the rates for certain commercial customers that will mitigate the highest rates for customers with lower load factors, as discussed in the next recommendation.[16]

[16] See Appendix C, *Small Commercial Customer Demand Charge Study*, for a discussion of rates for commercial customers as a function of load factor.

2.5.1.5. Commercial Rate Adjustment for Low Load Factor

The discussions with the EUC and the City Council in spring and summer 2015 highlighted the fact that relatively high rates for some commercial customers are linked to those customers' low load factor.[17] While the steep load factor curve embedded in Austin Energy's S2 rate supports the City Council's goal of encouraging energy efficiency throughout the community, that relationship may create affordability challenges for low load factor customers. Austin Energy, therefore, proposes to adjust the rates for certain low load factor customers with higher average rates per kWh usage by setting a floor on the applicable load factor.

2.5.1.6. Establish Uniformity in the Regulatory Charge

Austin Energy proposes to revise the methodology for allocating and assessing the Regulatory Charge. Currently, the total costs comprising the Regulatory Charge are allocated to customer classes according to the Four Coincident Peak (4CP) of each class in TY 2009. Under the tariff for the Regulatory Charge, the charge is reset each year to incorporate the latest Transmission Cost of Service (TCOS) matrix values approved by the Public Utility Commission of Texas and to true up any under or over recovery. In certain instances, the charge can be quite volatile for certain customer classes. For example, the Regulatory Charge in FY 2013 for the P1 class (Primary Service less than 3 MW) was $2.28 per kW, but rose to $3.79 per kW in FY 2014, while for the P2 class (Primary Service greater than or equal to 3 MW but less than 20 MW) was $2.92 per kW in FY 2013 but fell to $0.38 in FY 2014. Austin Energy proposes to use a uniform methodology to calculate the Regulatory Charge for all customer classes. There will be separate Regulatory Charges for classes assessed on an energy basis (Residential and S1 classes) from the charges for classes assessed on a demand basis. Similarly, Austin Energy will assess different rates for customers taking service at different voltage levels. This restructuring will eliminate the swings from year to year in the charge, make the charge more simple and predictable, and will be fair across all customer classes.

2.5.1.7. Establish Uniformity in the Community Benefit Charge

As with the Regulatory Charge, the Community Benefit Charge is subject to large swings from year to year for certain customer classes. Austin Energy proposes to use a uniform methodology to calculate the Community Benefit Charge for all customer classes. There will be separate Community Benefit Charges for classes assessed on an energy basis (Residential and S1 classes) from the charges for

[17] The NewGen study suggests a directly inverse relationship between average rates and load factor.

customers assessed on a demand basis. Similarly, Austin Energy will assess different rates for classes taking service at different voltage levels. This change applies only to the Energy Efficiency Services and Service Area Lighting components of the Community Benefit Charge. The Customer Assistance Program charge is already calculated on a uniform basis, though residential customers are assessed a different charge than non-residential customers and residential customers outside Austin's City limits pay a lower rate than comparable customers inside the City limits as a result of the settlement in PUCT Docket No. 40627.

2.5.1.8. Establish Consistency in Discount Policies

Austin Energy proposes applying all rate discounts offered in a consistent manner by providing a 20 percent discount off the base rate for virtually each customer currently receiving a discount. Discounts are proposed to be offered to state accounts following the expiration of their existing contract running through May 2017, Independent School District accounts within Austin Energy's territory, and military bases.

Austin Energy does not recommend continuation of the group worship facilities discount, also called the house of worship or HOW discount, as such discounts have been discontinued across the state due to growing concerns about the discount's constitutionality.

2.5.1.9. Collection of Revenues Funding Reserves

City Council sets Austin Energy's reserves policies annually as a component of the adoption of the City's financial policies for Austin Energy.[18] As explained in Chapter 4, Revenue Requirement, Austin Energy recommends a restructuring of its financial reserves and targets. Embedded in the revenue requirement is $19.4 million annually in reserves dedicated to the non-nuclear decommissioning reserve and $11.6 million dedicated to financial reserves.

2.6. ISSUES RESERVED FOR LATER RESEARCH

The electric industry — and in particular the distributed energy segment of retail electric service — is evolving rapidly, as are the regulatory policies that guide the industry. Traditional rates and rate structures must keep up with those changes. While Austin Energy is recommending preserving most components of the rate structure in this proceeding, staff recognize that more comprehensive changes may be needed in future rate adjustments to keep up with industry changes. In anticipation of its next

[18] The relevant financial policies of the City of Austin are summarized in Appendix D.

Cost of Service study and rate adjustment, Austin Energy anticipates conducting a series of studies to help prepare for a dynamic future. Some of the issues Austin Energy may study in the future include: cost of service for multifamily residences, lifeline study of minimum residential energy usage, cost of service for the downtown network, and power factor charges. Please refer to Appendix E for more detail on some of these possible studies.

Due to the significant deviation from cost of service for some customer classes and the list of issues for further research, Austin Energy suggests that the next cost of service update be conducted upon the conclusion of these studies in two to three years, rather than the maximum five years included in current City Council policy.

2.7. OVERVIEW OF AFFORDABILITY GOALS AND CURRENT COMPETITIVENESS METRICS

As noted above, the City Council has adopted goals for affordability for Austin Energy. Those goals limit future rate increases to no more than two percent per year and remain competitive by being in the lower half of rates in the state. The revenue requirement recommendation included in this Rates Report to Council fully complies with the first part of the affordability goal. As has been discussed over the past year, however, Austin Energy's rates are not currently in compliance for all customer classes with the second part of the goal. Appendix F discusses the competitiveness goal, including the challenges of remaining competitive in this market environment.

3. CREATING VALUE FOR AUSTIN ENERGY'S COMMUNITY

Austin Energy is a community-owned asset with the fundamental purpose of delivering electric services and creating long-lasting value for the residents of the greater Austin area. Value, at its most basic level, is provided to the residents through the profits Austin Energy earns each year by generating, selling, and delivering electricity to customers. These profits are returned to the community as investments in parks, health and human support services, and myriad other ways. However, Austin Energy also generates non-economic value by operating in a way that reflects the priorities and principles of its community. These values are promoted through environmental stewardship, energy conservation, and renewable energy and by providing a comprehensive suite of customer assistance programs beyond what is offered traditionally in the electric utility industry.

These goals, to provide both financial and communal value to its customers, guide Austin Energy's operations and inform strategic business decisions. For example, Austin Energy's work in the wholesale electricity market creates an inherent economic value that can be passed on to customers and residents alike. Customer success programs — like the 3·1·1 call center, key accounts management, and integrative technology initiatives — enable customers to interact easily with Austin Energy, to gain access to up-to-date information, and to obtain cutting edge services. These programs are designed to give customers the services they want at an affordable price, while shielding them from the risks of the volatile business environment in which Austin Energy operates.

This chapter of the Rates Report to Council describes the dynamic regulatory and business environment encountered by today's electric utilities. It discusses some of Austin Energy's fundamental strategies used to mitigate the utility's exposure to the risks created by that environment. Finally, this chapter addresses the utility's key business units designed to protect customers from the volatile energy market and to provide customers with beneficial programs that reflect the community's values.

3.1. REGULATORY ENVIRONMENT

Given the complex safety issues, consumer protection concerns, infrastructure security interests, and often contentious energy policy issues that encircle the electric utility industry, many local, state, and federal bodies exercise authority over Austin Energy's operations in some form or fashion. Austin Energy navigates the complex array of rules and regulations that govern the electric utility industry by balancing the competing needs of customer value, community priorities, financial stability, and reliable provision of electricity. The following section provides a high-level overview of each these various regulatory bodies and their specific authority over Austin Energy.

3.1.1. State of Texas

Nearly all Texas' authority to oversee the electric utility industry is found in the laws enacted by the Texas Legislature, including those that enable the City of Austin to maintain exclusive control over Austin Energy's retail service territory. The state's main electric utility law is the Public Utility Regulatory Act (PURA).[19] Due to significant state restructuring of the electric utility industry in 1999, several portions of PURA do not apply to Austin Energy as a municipally owned utility. However, Austin Energy remains subject to many PURA provisions which address fundamental business practices as well as specific operational procedures.[20]

The legislature uses a committee structure similar to those recently established by the Austin City Council to conduct the majority of its detailed policymaking. While future policy issues will be assigned to specific committees by the leaders of each chamber of the legislature, in the past, the Senate's Business & Commerce and Natural Resources committees have taken a leading role in developing electric utility regulations. In the House of Representatives, the committees on State Affairs and Environmental Regulation have been responsible for oversight of the industry.

Two primary state agencies — the Public Utility Commission of Texas (PUCT) and the Texas Commission on Environmental Quality (TCEQ) — have been authorized to adopt rules that implement the laws and to serve as key regulators of the industry, including Austin Energy.

3.1.2. Austin City Council

Because Austin Energy is a municipally owned utility, the Austin City Council serves as Austin Energy's primary regulator with the authority to set retail rates, issue debt secured with pledges of future revenues, and purchase and sell major capital assets like substations and power plants. As Austin Energy's governing body, the City Council also establishes long-term strategic plans, sets financial policies, and focuses on community values and ratepayer interests when guiding the direction of the near-term operation of the utility. Through its community advisory board, the Electric Utility Commission, the City Council receives public input regarding the policies and procedures of the electric utility, including electric rate structure, power supply costs and charges, customer services, budget,

[19] Public Utility Regulatory Act, Tex. Util. Code Ann. §§ 11.001-66.016 (West 2007 & Supp. 2014)

[20] Later sections of this report will cover in detail the restructuring of the industry through the comprehensive Senate Bill 7 enacted in 1999.

strategic planning, and regulatory compliance. The City Council also receives public input from the Resource Management Commission regarding efficient use of energy, alternate energy technologies, renewable energy resources, and the conservation of energy.

3.1.3. Public Utility Commission of Texas

The Public Utility Commission of Texas regulates the state's electric, telecommunication, and water and sewer utilities; implements legislation affecting those utilities; and offers customer assistance in resolving consumer complaints. The PUCT adopts, and Austin Energy must adhere to, rules governing the wholesale competitive market, the ancillary services market, and procurement and dispatch of products designed to maintain the reliability and stability of electric service in Texas. In addition, the PUCT has full regulatory control over the development and construction of and access to the state's transmission system. Applications to build new transmission lines, upgrade existing lines, and set rates to recover those infrastructure costs generally must be approved by the PUCT. Therefore, as an owner of transmission facilities and a user of the state's transmission system, Austin Energy must comply with the PUCT's Transmission Cost of Service rules.

Importantly, the PUCT maintains appellate jurisdiction over the retail rates paid by Austin Energy's customers located outside of the Austin City limits. If outside City customers want to contest the retail rates set by the City Council, they may file an appeal with the PUCT seeking relief.

3.1.4. Texas Commission on Environmental Quality

The Texas Commission on Environmental Quality is the state agency tasked with protecting Texas' natural resources and the public health of the state's residents. Among other responsibilities, TCEQ oversees all air permitting activities and air quality monitoring in the state. The agency implements plans to protect and restore air quality in cooperation with local, regional, state, and federal stakeholders. Additionally, TCEQ tracks progress toward environmental goals, adapting plans as necessary.

The majority of the state's air quality requirements are authorized by the federal environmental regulations that have been adopted by the U.S. Environmental Protection Agency (EPA) and are enforced by TCEQ. For example, Austin Energy is required to apply to TCEQ for air permits when operational changes at the utility's power plants result in a change in the amount of electricity generated, and the utility must provide air quality monitoring data to demonstrate compliance with state and federal environmental regulations.

3.1.5. Federal Government

The United States federal government has enacted laws that regulate the operation of electric utilities in the country. Most notably, the Public Utility Holding Company Act,[21] the Clean Air Act,[22] Clean Water Act,[23] Public Utility Regulatory Policies Act,[24] and the Energy Policy Acts of 1992[25] and 2005[26] all significantly impact the operations of electric utilities. Agencies like the EPA, the Nuclear Regulatory Commission (NRC), the Federal Electric Regulatory Commission (FERC), and the Securities and Exchange Commission (SEC) adopt rules that implement these federal laws. The EPA in particular has implemented several rules which significantly impact Austin Energy's operations, including the National Ambient Air Quality Standards (regulating SO_2, NO_x, CO, O_3, and particulate matter), the Mercury and Air Toxics Standards, and the Cross-State Air Pollution Rule. Recently, the EPA finalized its Clean Power Plan, a federal rule that will regulate the emission of CO_2 and other greenhouse gases. While the Clean Power Plan is now subject to various legal challenges, Austin Energy has chosen to intervene in *West Virginia v. EPA,* a case now pending in the federal court of appeals of Washington, D.C., in support of the EPA and its authority to adopt these new rules.

While many federal agencies impact Austin Energy's operations, this report focuses on the few that establish a regulatory framework for regional or state level oversight.[27]

3.1.6. Federal Energy Regulatory Commission

The Federal Energy Regulatory Commission is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. Among its many responsibilities, FERC:

- Regulates the transmission and wholesale sales of electricity in interstate commerce;
- Reviews certain mergers, acquisitions, and corporate transactions by electric companies;
- Reviews the siting application for electric transmission projects under limited circumstances;

[21] 42 U.S.C. § 16451 et seq. (1935). Repealed by the Energy Policy Act of 2005.

[22] 42 U.S.C. §7401 et seq. (1970) and as amended in 1990 by Pub. L. No. 101-549.

[23] 33 U.S.C. §§1251-1387 (1977).

[24] Public Utilities Regulatory Policies Act of 1978, Pub. L. No. 95-617.

[25] Energy Policy Act of 1992, Pub. L. No. 102-486.

[26] Energy Policy Act of 2005, Pub. L. No. 109-58.

[27] The exclusion of the other agencies does not intend to diminish the importance of their regulatory impact; rather, it serves to keep this section of the report to a reasonable length.

- Protects the reliability of the high voltage interstate transmission system through mandatory reliability standards;
- Monitors and investigates energy markets;
- Enforces regulatory requirements by imposing civil penalties and other means; and
- Administers accounting and financial reporting of regulations and conduct for regulated companies.

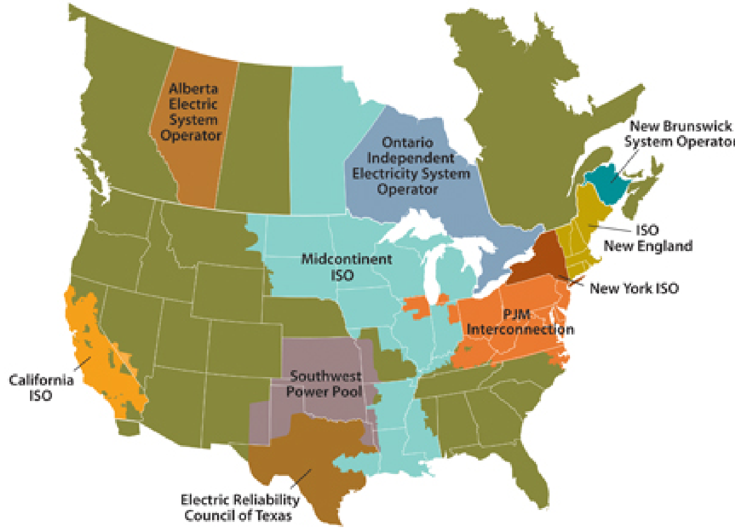
In the late 1990s, FERC explored ways for areas with high concentrations of electric utility infrastructure to satisfy the requirement of providing non-discriminatory access to the transmission system. As a result, FERC encouraged the voluntary formation of Independent System Operators (ISO)[28] to administer the transmission grid on a regional basis throughout the United States and Canada.

An ISO serves as the third-party independent operator of that area's transmission system. These independent agencies ensure that no preference is given in the dispatch of a utility-owned generator over a competitive generator. By providing fair transmission access, these agencies facilitate competition, which benefits consumers. ISOs support settlement transactions between buyers and sellers of electricity and engage in regional planning to ensure that the right infrastructure gets built in the right place, at the right time. They accomplish all of this over a large regional area, providing greater value to customers at every level of the supply chain than would be seen in the more piecemeal utility-by-utility approach.

ISOs cover many regions of the country with two-thirds of the United States' economic activity occurring within their boundaries. The map in Figure 3.1 below shows the current ISOs:

[28] ISOs can also be referred to as Regional Transmission Operators. This report will use the term ISO to keep consistent with ERCOT lexicon.

Figure 3.1. Map of Independent System Operators in America and Canada[29]



This region-wide approach improves system reliability by coordinating efficient power flows and transactions. Previously, these transmission lines may have passed through numerous individual utility territories and may have had to pay transaction charges for every utility border crossed. Using a broader planning approach allows pooling of resources on both the supply side and the transportation side, resulting in a reduction of the need for more power plants, supplanting older and less efficient plants, and coordinating the construction of transmission facilities. By using a broad, regional planning approach, ISOs help save consumers money and substantially reduce emissions.

In addition to overseeing the coordination of regional transmission services, the Energy Policy Act of 2005 gave FERC new and broad jurisdiction over the reliability of electric transmission facilities operated at 100 kilovolts (kV) and higher. Based on this authority, FERC adopted many new Reliability Standards: as of today, there are almost 100 Reliability Standards in effect. Within those standards are approximately 642 requirements related to a number of dimensions of reliability, such as voltage and reactive power, protection and control, transmission planning and operations, and emergency preparedness and operation.

The Electric Reliability Council of Texas, discussed immediately below, serves as the ISO for approximately 90 percent of Texas, including Austin Energy's service territory. Because the Texas Legislature has taken great effort to maintain a limited number and type of transmission interconnections to the states bordering Texas, FERC has limited oversight of the ERCOT region. As a result, Austin Energy is responsible for adhering to FERC standards in reliable system operation.

[29] The areas shaded in dark green are not represented by ISOs.

3.1.7. <u>Electric Reliability Council of Texas</u>

The Electric Reliability Council of Texas manages the flow of electric power to 24 million Texas customers, representing about 90 percent of the state's electric load.[30] As the ISO for the region, ERCOT schedules power on an electric grid that connects more than 43,000 miles of transmission lines and 550 generation units. ERCOT also performs financial settlement for the competitive wholesale market and administers retail switching for 7 million premises in competitive choice areas. This financial settlement process is further explained in the Business Environment section of this chapter.

ERCOT is a membership-based nonprofit corporation, governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature. ERCOT's members include consumers, cooperatives, generators, power marketers, retail electric providers, investor-owned electric utilities (transmission and distribution providers), and municipally owned electric utilities. The following map outlines ERCOT’s jurisdictional area within the state of Texas.

FIGURE 3.2. Map of the ERCOT ISO Region

Five years ago, ERCOT designed and launched its Nodal Wholesale Market. Prior to this transition, the ERCOT wholesale market operated under a portfolio dispatch arrangement in which each generation owner scheduled its own resource output. Under the old system, Austin Energy could control when its generating units, such as Sand Hill Energy Center and Decker Creek Power Station, would run

[30] The Southwest Power Pool oversees the territory in the Texas panhandle and northeast Texas not controlled by ERCOT. The Midcontinent Independent System Operator oversees the territories in southeast Texas not controlled by ERCOT. The far western portion of the state is not part of any ISO.

and the power produced by the units would be sold into the market. In 2010, this market system was replaced by the Nodal Market design with a centralized economic dispatch model run by ERCOT that simultaneously balances cost and system reliability. In the Nodal Market design, ERCOT tells each generation resource owner how much to dispatch its units based upon its availability and the price it offers into the market. Rather than remain exposed to real-time market prices, purchasers of wholesale electricity[31] can lock in the price they pay for energy through bilateral contracting with generation owners, a day-ahead market, and other market tools.

An important aspect of ERCOT's management responsibility is to control and account for congestion on the transmission lines used to deliver electricity over the region. Congestion in the transmission system refers to situations in which either the supply of or demand for electricity exceeds the rated capacity of the transmission lines that serve a particular area. When congestion occurs, ERCOT must replace the constrained power with power from different and often more expensive resources. In the Nodal Market, all congestion charges are reflected in the energy prices at the more than 4,000 delivery points, or "nodes." Nodal pricing has decreased congestion by exposing pockets where electricity is expensive, and has encouraged either generation or transmission solutions to lower those costs.

ERCOT's market rules[32] – including the Nodal Protocols, Market Guides, and Other Binding Documents – govern wholesale, commercial, and emergency systems operations; metering and other data requirements; and planning criteria, among other areas. Austin Energy must comport with hundreds of rules and guidelines because it participates in the ERCOT market as a Load Serving Entity (LSE), generator of wholesale energy and capacity products, and provider of transmission and distribution services. Significantly, Austin Energy is subject to the rules governing sales and purchases through the wholesale market, provision of energy resources, and reliable operation of the region's electric system.

Austin Energy is also a corporate member of ERCOT and actively participates in its governance. Many Austin Energy employees serve or have served as leaders of ERCOT's stakeholder rulemaking process, including as a member of its board of directors, as chair and vice-chair of its Technical Advisory

[31] In ERCOT, these companies are called Load Serving Entities, and they purchase electricity at wholesale and sell it to end-use customers at retail prices. Municipally owned utilities, like Austin Energy, comprise one type of Load Serving Entity. See Chapter 2.2 for greater detail.

[32] See, ERCOT, *Market Rules* at www.ercot.com/mktrules/index.html.

Committee,[33] and as chairs of subcommittees and working groups that conduct detailed market-based analyses that inform the region's policy development.

3.1.8. North American Electric Reliability Corporation

The North American Electric Reliability Corporation (NERC) is a nonprofit international regulatory authority whose mission is to ensure the reliability of the bulk power system in North America. NERC is subject to oversight by FERC and governmental authorities in Canada. NERC develops and enforces Reliability Standards as mandated by FERC; annually assesses seasonal and long-term reliability; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people.

NERC develops federally-required clear, reasonable and technically sound Reliability Standards. NERC then obtains authorization from FERC to implement and enforce these standards throughout its jurisdiction. They establish threshold requirements for ensuring the bulk electric system is planned, operated, and maintained in a manner that minimizes risks of cascading power outages, avoids damage to major equipment, and limits interruptions of bulk electric supply.

Additionally, NERC works to identify the most significant risks to reliability, help plan for the mitigation of reliability risks, and promote a culture of reliability excellence. The agency works with industry stakeholders and experts to ensure the mitigation of known risks to reliability and creates a collaborative learning environment analyzing events, communicating lessons learned, tracking recommendations, and implementing best practices. As a stakeholder in the bulk electric system — with generation and transmission assets — Austin Energy is subject to NERC's reliability standards and must maintain its operations within certain thresholds to avoid creating significant risks to the bulk electric system. Failure to meet the standards could result in significant monetary sanctions.

Figure 3.3 delineates the coordinating regions that are responsible for overseeing the implementation of NERC Reliability Standards.

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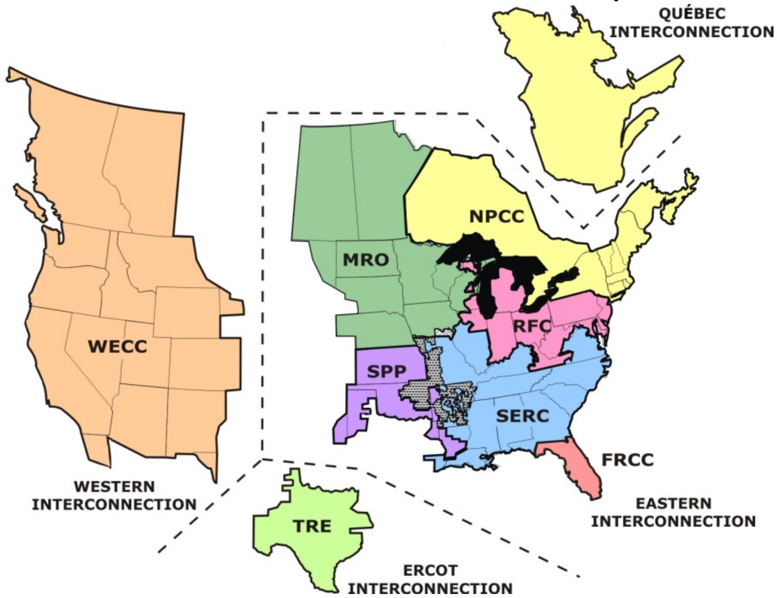
[33] This committee makes technical and policy recommendations to the ERCOT board of directors.

FIGURE 3.3. NERC Interconnection Map



NERC delegated its Reliability Standard enforcement authority to the Texas Reliability Entity (Texas RE).

3.1.9. Texas Reliability Entity

Texas Reliability Entity is the FERC-approved Regional Entity for the ERCOT region. Texas RE is authorized by its delegation agreement with NERC to develop, monitor, assess, and enforce compliance with NERC Reliability Standards, and assess and periodically report on the reliability and adequacy of the bulk-power system.

In addition, Texas RE is authorized by the PUCT and permitted by NERC to investigate compliance with the ERCOT Protocols and Operating Guides, working with PUCT staff to address any potential protocol violations. Austin Energy must adhere to the compliance rules established by Texas RE.

3.1.10. Conclusion

Austin Energy is regulated by many oversight bodies at many different levels of government and has a legal responsibility to adhere to the rules and regulations of all of these entities. To ensure compliance with these rules and regulations, Austin Energy's practices and procedures can be audited at the sole discretion of most of the above agencies.

Failure to comply with the policies of many of these regulators can result in hefty fines. In particular, failure to follow ERCOT or NERC standards comes with fines from tens to hundreds of thousands of dollars. To avoid these penalties and to fulfill its role as a steward of the community's needs, Austin Energy spends a significant amount of employee resources understanding, complying with, and, to the extent possible, shaping these regulations that impact utility operations. In the fulfillment of this vital function, Austin Energy actively balances the expectations of the community with the needs of its customers, the demands of the markets, and the requirements of the government to provide the best value to the City of Austin.

3.2. BUSINESS ENVIRONMENT

Sixteen years ago, the Texas Legislature restructured the electric utility industry through passage of Senate Bill 7 (SB 7), transitioning the state from the traditional monopoly utility model toward an open market system that allows most retail customers in the state to choose the company from which they buy their electricity. Prior to SB 7, utilities maintained exclusive control over their service areas, meaning that one utility could not sell electricity to retail customers located in another utility's service area. These legacy utilities built power plants and transmission and distribution systems dedicated to delivering electricity solely to their "captive customers." The result of this traditional utility model was a patchwork of cost-intensive infrastructure that shared little coordination and could not take advantage of economies of scale in the service of electricity to consumers throughout the state.

SB 7's passage in 1999 opened up the vast majority of these monopoly service areas, and the legacy utilities were required to unbundle their business units into three distinct types of companies:

- Generation companies: businesses that produce electricity by various methods including natural gas, coal, nuclear power, wind, water, and solar.
- Transmission and distribution companies: businesses responsible for the actual delivery of the electricity over the poles and wires from the power plant to the electricity customer.
- Retail Electric Providers (REPs): companies that sell electricity to retail customers at competitive rates.

As a result of this restructuring, about 20 million Texas consumers can choose from more than 100 different REPs offering more than 300 different plans on the basis of cost, contract duration, percentage of renewable energy, and fixed versus variable rate plans, among other details.[34] The PUCT

[34] Report to the 84th Texas Legislature, Scope of Competition in Electric Markets in Texas, Public Utility Commission of Texas, January 2015, pg. 3.

estimates that about 90 percent of eligible customers have switched from their legacy utility retailer to a new REP since the market opened in 2002.[35]

However, the Legislature intentionally did not deregulate all of the state's electric utilities. Instead, the Legislature created a second separate model by designating some utilities of that were not required to open up to retail electric competition. These utilities, called Non Opt-In Entities (NOIEs), serve areas in Austin, San Antonio, Garland, Brownsville, and more than sixty other towns, cities, and rural areas across the state. NOIEs were exempted from retail electric competition because these legacy utilities were and continue to be owned and operated by the local governments and consumers of these towns, cities, and rural areas. Unlike the investor owned companies in places like Houston or Dallas which viewed electricity service as means to create value and wealth for their shareholders, the NOIEs used customer dollars to build robust electricity systems for the benefit of their respective communities and customers. Austin Energy is an example of a Municipally Owned Utility (MOU) that operates in a non-opt in area. Of the 24 million electric consumers in Texas, some four million Texans are served at the retail sales level by MOUs in non-opt in areas.[36]

Today, MOUs continue to retain the exclusive right to sell electricity to retail consumers located in their service areas.[37] However, MOUs still must operate within the larger context of the restructured electric utility industry, like all the investor owned companies. In this larger context, there are several regulatory constructs that result in strict competition among most Texas utilities: the most important and influential of these competition-inducing constructs is the wholesale electricity market.

The regulatory structure of SB 7 created a market through which all electricity is bought and sold at the wholesale level. Generation companies — like NRG, Calpine, and Luminant — and MOUs that own generation resources — like Austin Energy — are required to sell all of the electricity they produce through the wholesale market. Similarly, all REPs — like Direct Energy or Reliant Energy — and MOUs that serve retail electric customers — like Austin Energy — or collectively, Load Serving Entities, are required to buy all of the electricity needed to serve their retail customers through the wholesale market. The LSEs then sell that electricity to their customers at the retail level. While the construct is similar to many commodities markets in which supply and demand are the two forces that set wholesale

[35] Report to the 84th Texas Legislature, Scope of Competition in Electric Markets in Texas, Public Utility Commission of Texas, January 2015, pg. 3.

[36] Texas Public Power Association, *General Information Brochure*. www.tppa.com/wp-content/uploads/TPPA-General-Info-Brochure.pdf

[37] The legislature has defined a legal process by which non-opt in utilities can open their territories to competition. *See* PURA § 40.

prices, the reliability of electric service delivery constitutes a third coequal force that contributes to wholesale price formation.[38] To balance these competing forces, ERCOT designed a market that can measure in real time the supply, demand, and reliability of electric service in the region.

In the ERCOT wholesale market, the ISO determines how much electricity is required to meet the demand of all ERCOT-located consumers (load) at least once every five minutes of every day of the year. Then, the operator determines the amount of resources that are available to meet that load. Each generating company offers to sell energy from its generation resources to the market at a price that is typically consistent with their resources' marginal operating costs and operational limitations. ERCOT takes each offer and stacks them in order from least cost to highest cost. Then, ERCOT selects the least number of resources required to meet the forecasted load for that next five-minute interval, starting with the lowest cost resource first. The price of the last resource needed to meet the forecasted load sets the price for all resources required in that five-minute interval. By attempting to minimize the operating costs of their resources in an effort to be selected to provide energy in the next five-minute interval, generating companies help improve the economic efficiency of the market, and load can be served with the lowest cost resources available, regardless of ownership.

Based on the cost structure and amount of resources that are available at that moment, a computer algorithm determines the amount of electricity each resource is required to produce for the next five minute period. Every fifteen minutes the five-minute interval prices are averaged together and an invoice is created for each LSE that bought electricity during that fifteen minute period. One week later, ERCOT issues an initial invoice to the LSEs, who must in turn send payment back to ERCOT the next day. Three days after the initial invoice is sent, ERCOT issues payment to the generating companies whose resources were dispatched during that operating day. About two months later, a final statement is issued that accounts for any adjustments that must be made to the settlement process.[39]

Several factors influence the demand for or supply of energy, and in turn help establish market prices, including the marginal operating costs of the resource fleet, time of day, season of the year,

[38] Under ERCOT's Security Constrained Economic Dispatch model, reliability of the system is the primary threshold that ERCOT must meet when selecting the generation dispatch for the next interval. In other words, ERCOT attempts to select the least cost resources that meet system reliability (or system security) requirements.

[39] ERCOT's settlement timeline lays the groundwork for much of the inherent risk embedded in wholesale market price volatility. LSEs must have enough cash on hand to send payment to ERCOT within one week of the operating day. For example, if expected prices are $50/ MWh and a utility expects to buy 2,000 MWh of energy, the utility anticipates a payment of $100,000 for that energy. If prices unexpectedly reach the market cap of $9,000/ MWh, the LSE must pay $18,000,000 for that same energy. While the probability of this scenario actually occurring is low, the risk it poses to LSEs – and their customers – is very high.

weather in different parts of the state, and resource availability. Prices can range from as low as negative $250.00 per megawatt-hour (MWh) to more than $9,000 per MWh.[40] In 2014, the average wholesale market price was $40.64 per MWh. This means, on average, LSEs paid $40.64 for every MWh of electricity that they bought in 2014 and generating companies received, on average, $40.64 for every MWh of electricity they produced in 2014.[41, 42]

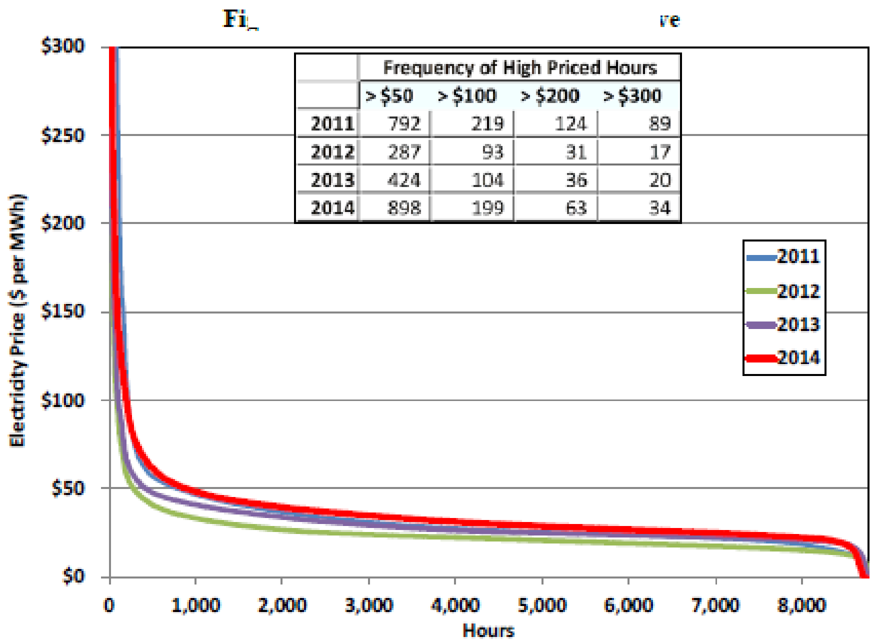
Over the past four years, wholesale market prices have been relatively stable. Figure 3.4 shows that wholesale market prices have ranged between $0 and $50 per MWh in about 32,000 of the total 35,064 operating hours in the years 2011 through 2014. Figure 3.4 also demonstrates that pricing events above the average market price occur very infrequently. Approximately 3 percent of all hours (about 1,000 hours over those four years) had wholesale prices above $100 per MWh.

[40] Wholesale prices can drop below $0 per MWh as wind generators can offset the lost revenue from the negative wholesale market prices with production tax credits from the federal government. For example, on September 14, 2015, ERCOT wholesale prices dropped below $0 per MWh due to decreasing demand for electricity combined with an extremely high amount of wind generation output (over 11,000 MW). (*See,* Platts, "ERCOT Power Prices Move Negative," Sept. 14, 2015.) At a node, prices can drop as low as -$250 per MWh due to congestion.

[41] LSEs can enter into contracts in which the price for electricity is predetermined for a period of time in advance of the actual moment when the electricity is consumed. Contracts can occur as bilateral agreements or can be arranged through ERCOT's Day Ahead Market, which imposes a financial commitment on a third party to ensure that the required electricity is produced at the agreed-to delivery time. These prearranged agreements usually cost more than the expected real-time market price, and LSEs use them to serve as a financial hedge against unforeseen price spikes.

[42] The average wholesale price for electricity also includes charges for congestion on the state's transmission system. Just like a highway, when too much electricity tries to move through transmission lines, the line can become congested. ERCOT uses a computer algorithm to apply a congestion price adder to the cost of the delivered energy. Negative price adders at a resource node are economic signals for a resource to stop producing energy that is contributing to sustained congestion.

Figure 3.4. ERCOT Price Duration Curve 2011-2014[43]



These price spikes typically occur either when resource supply is constrained due to a sudden unavailability of generation or when a rapid escalation of demand for electricity exceeds expectations. As market prices increase, economic signals are sent to generating companies to make more resources available to dispatch, if possible. Depending on the severity of the supply shortage, these 'price excursions' can escalate very steeply and very quickly: prices can increase 100-fold in just a 15 or 30 minute period. As more resources begin generating, the supply constraint is relieved and market prices tend to drop back to the more normal levels.

The design of the ERCOT Nodal Market tends to drive down average wholesale prices for two primary reasons. First, generating companies want to be in a position to take advantage of the rare and fleeting price excursion and therefore, tend to have more resources online and available for dispatch during the times of year when supply shortages occur most frequently.[44] Second, generating companies with a contractual obligation to deliver a certain amount of energy at a certain time interval tend to keep excess generation online to protect against a forced outage in real-time operations. If the

[43] Potomac Economics, *2014 State of the Market Report for the ERCOT Wholesale Electricity Markets*, prepared as Independent Market Monitor for the ERCOT Wholesale Market, Austin, Texas (July 2015), pg. 6.

[44] While one typically considers the summer months to be the most costly due to the highest levels of demand — and on average that is correct — dramatic price excursions tend to occur in the winter and spring when weather variations are more extreme and when generating companies typical perform routine maintenance on their plants.

generation company experiences an unforeseen loss of one of its resources, the company would be required to buy additional energy off the real-time market to meet its contractual requirements. Power in such a situation mostly likely would be much more expensive than the power the company originally sold. Third, LSEs need to protect themselves from these unforeseen high pricing events and therefore, tend to sign contracts that financially guarantee the delivery of electricity at a fixed price, regardless of what happens in the real-time market. By hedging the real-time market with bilateral contracts (or through the Day Ahead Market), LSEs shift the financial risk of real-time market exposure back to the generating company with which the LSE contracted, thus creating another financial incentive for the generating companies to ensure a reliable and predictable supply of electricity.

The economic efficiency of the ERCOT wholesale market not only results in lower average market prices but, also drives operational effectiveness of the generating fleet. With such low average wholesale prices, generating companies have to earn a significant portion of their annual revenues in the few hours each year when prices increase significantly above the market average. Figure 3.5 shows two different pricing scenarios during the 6:00 AM hour on a typical spring day. The table shows the impact price plays on a generating company's ability to earn enough revenue to cover its average operating costs. In Scenario 1, if a hypothetical resource with a capacity of 500 MW has an average operating cost of $40 per MWh, the generating company could earn the $20,000 it costs to produce the 500 MWh if market prices are $40 for an entire hour. Alternatively, Scenario 2 shows that if the market price jumps to $500 per MWh for one fifteen-minute interval, the generating company can earn significantly more than its $20,000 average cost for that entire hour.

Figure 3.5. Generator Interval Pricing Scenario

	Scenario 1			*Scenario 2*		
Interval Ending	**Price ($/MWh)**	**MWs Dispatched**	**Revenue ($)**	**Price ($/MWh)**	**MWs Dispatched**	**Revenue ($)**
0615	40	500	5,000	40	500	5,000
0630	40	500	5,000	500	500	62,500
0645	40	500	5,000	40	500	5,000
0700	40	500	5,000	40	500	5,000
Total			**$20,000**			**$77,500**

If a generating company can anticipate that a price spike might occur, it may be prudent for the utility to run this resource at a loss for more than an hour if it is able and ready to capitalize on that additional revenue earned in interval ending 0630. In practice, generating companies in ERCOT must be able to operate their resources efficiently by keeping their resources well maintained while working constantly to lower operating costs as much as possible. By maximizing resource availability for dispatch and minimizing costs, the generating companies have a better chance to take advantage of those quick and infrequent high price events.

This fundamental principle of the ERCOT wholesale market — maximizing resource economic value — is as true for Austin Energy as it is for any other generating company. However, as a municipally owned utility with an obligation to serve its customers, the value of Austin Energy's resource portfolio provides dual benefits. Not only can Austin Energy seek to use its resource fleet to capture economic value during high price events as explained above, the utility can also use its resource fleet to protect its customers from exposure to the extremes of real-time market pricing.

Like all other LSEs, Austin Energy must purchase enough electricity each day to meet its customers' needs at any given point in time. As noted above, Austin Energy buys all of its energy through the ERCOT wholesale market, regardless of whether its own resource fleet is instructed by ERCOT to dispatch energy. If market prices are lower than the operating costs of the Austin Energy resource fleet, then Austin Energy can buy its energy needs through the real-time market and minimize costs to its customers. But as prices increase, the revenue earned through the dispatch of Austin Energy's resources can offset some of the cost of buying electricity for its customers.

At Austin Energy, all costs to buy energy from the market and all revenues earned from selling energy into the market are accounted for on the customer bill in the Power Supply Adjustment. Figure 3.6 demonstrates how power supply costs can be altered when a utility has both load to serve and generation to sell.

Figure 3.6. Hedging Power Supply Costs with Generation

	Low Price	Medium Price	High Price
Price to Buy ($/MWh)	25	75	500
MWh needed	2,000	2,000	2,000
Power Supply Cost	*$50,000*	*$150,000*	*$1,000,000*
Price to Sell ($/MWh)	25	75	500
MWh Sold	1,000	1,000	1,000
Gross Revenue	$25,000	$75,000	$500,000
Less Operating Costs ($35 /MWh)	(35,000)	(35,000)	(35,000)
Net Earnings/(Loss) from Sales	*($10,000)*	*$45,000*	*$465,000*
Total Power Supply Cost	**$60,000**	**$105,000**	**$535,000**
Resource Fleet % Savings/(Cost)	(20%)	30%	46.5%

In the Low Price scenario, the utility's resource fleet would increase power supply costs by $10,000 because market prices are less than the utility's operating cost. In practice, a utility would be unlikely to offer a resource for dispatch at a price significantly below its marginal operating cost.[45] As prices rise, however, a utility can reduce power supply costs to its customers if it is able to sell energy from its generation resources. For example, in the Medium Price scenario, the utility is able to reduce total power supply costs by 30 percent because market prices are higher than its marginal operating costs.

Owning and operating a resource fleet can provide a utility with market price risk mitigation because sudden price increases are not limited to certain hours of the day or months of the year. On the contrary, high market price events can and do occur throughout the year. With generation capacity available for market dispatch, AE's generation fleet can earn revenues whenever market conditions are ripe and return revenues back to the customers as an offset to their power supply charges. These examples demonstrate how a utility can use its resource fleet as a hedge against rising market prices.

Austin Energy's resource fleet also provides value to its customers in the provision of Ancillary Services. In order to ensure grid reliability, ERCOT requires all LSEs to buy Ancillary Services based on the LSEs' ratio share of its amount of load compared to the total ERCOT system load. Ancillary Services are

[45] There are situations in which a utility would offer in its resources below cost. For example, Austin Energy is required to purchase all of the energy produced by the renewable resources that are under contract through Power Purchase Agreements at a fixed price regardless of the market price. Austin Energy offers in the energy from its PPAs and accepts whatever price the market is willing to bear at that given moment, thereby offsetting some or all of the cost of the purchased power. These out-of-merit offers ensure that Austin Energy minimize power supply costs to its customers as much as possible.

designed to facilitate and support the continuous supply of electricity so supply will always meet demand and they are divided into different types of capacity-based products that must be available for use within a defined timeframe. Depending on the product, the resources can be provided by either generation or load resources. For example, Responsive Reserve Service is a category of Ancillary Service in which a generation resource must be able to deliver its full amount of proscribed energy within ten minutes of an ERCOT dispatch order. Alternatively, load resources can provide Responsive Reserve Service if the resource is able to decrease consumption of its full amount of proscribed energy within ten minutes of an ERCOT curtailment order.

As a way to maximize the value of its fleet, Austin Energy can hedge the cost of its Ancillary Services obligation and offer additional capacity into the Ancillary Services market for purchase by ERCOT for use by other LSEs. Decker Creek Power Station, for example, is often earmarked to provide Ancillary Service for Austin Energy. Because its marginal operating costs tend to be higher than the average wholesale market price, Decker Creek will not always be dispatched to provide energy in the real-time market. However, Austin Energy looks at market and grid conditions and assesses when there is potential to earn revenue by making Decker Creek available to the Ancillary Services market and once online, Decker Creek can more readily take advantage of scarcity pricing events.

Most days, Austin Energy does offer capacity from its generation fleet to provide ancillary services to the ERCOT market. Once a generator has committed to providing any of these vital grid reliability products, failure to perform to the required performance standards can result in an investigation by the Texas RE and a fine imposed by the PUCT. Repeated failure to perform can result in the forfeiture of the utility's certification to provided ancillary services. Performance standards are also required of generation resources that provide energy. For example, generation resources in the ERCOT market are required to be frequency responsive and always have their governors in service.

Repeated failure to meet performance standards can result in the forfeiture of a resource's certification to operate in the ERCOT market. The serious importance that ERCOT and the PUCT place on performance standards for resources providing energy and Ancillary Services stems directly from NERC reliability standards. The severity of the penalties for failure to meet these performance standards demonstrates the regulators' intent to place utilities on the front line of ensuring system reliability. By keeping its fleet well maintained, Austin Energy can further minimize its exposure to the real-time market, reduce compliance risks associated with Ancillary Services, and earn some revenues that are returned to its customers through a reduction in the net Power Supply Adjustment charge.

3.3. AUSTIN ENERGY OPERATIONS

The previous two sections of this chapter focused on the overarching business and regulatory environments in which Austin Energy operates. In essence, they provided an overview of the structure and rules that govern the conduct of Austin Energy's operations. The following sections will discuss how Austin Energy uses its physical and human resources to provide services that benefit its customers and the City of Austin.

3.3.1. Power Production

At the core of Austin Energy's operations is the production and sale of electricity. Austin Energy owns and operates several power plants and contracts for the production of energy from plants owned by other entities. Initially, these power production operations served Austin Energy's customers directly by meeting their daily demand for electricity. Since the restructuring of the ERCOT wholesale market, however, Austin Energy owned or contracted power plants no longer serve Austin Energy customers directly. Instead, the energy produced is sold into the wholesale market. Through its power production operations, Austin Energy strives to provide maximum financial value to its customers by seeking to earn revenue through the sale of energy into the wholesale market and reduce costs of its resource fleet as compared with average wholesale market prices.

Austin Energy generated 8.4 billion kilowatt-hours of power for fiscal year 2014 from its owned thermal power plants. A kWh is a quantitative measure of electric current flow equivalent to one thousand watts being used continuously for a period of one hour.[46] Power Production's main objectives are focused on safe, clean, reliable and affordable operations of each of its four thermal generating resources – Sand Hill Energy Center (SHEC), Decker Creek Power Station, a share of Fayette Power Plant (FPP), and a share of South Texas Project (STP). In addition, Austin Energy has renewable Power Purchase Agreements (PPAs) that provide fixed price renewable energy supply for AE customers.

Austin Energy's generation mix in FY 2014 by source was 32.1 percent coal, 26.9 percent nuclear, 25.5 percent renewable, and 15.3 percent natural gas. Coal supplies for FPP are procured through contracts that are managed to minimize cost and risk for Austin Energy customers. Austin Energy also uses natural gas contracts and multiple suppliers to reduce risk and cost of production for AE customers. Fuel for the South Texas Project is procured through a long term contract with Westinghouse, which provides some of the most competitively priced fuel in the industry.

[46] Kilowatt hours is the unit most commonly used to measure electrical energy, as opposed to kilowatt, which is an instantaneous measure of available power, also referred to as the capacity.

In the following section, the Rates Report to Council will outline Austin Energy's main resources available for market dispatch.

3.3.1.1. Sand Hill Energy Center

Sand Hill Energy Center is located in southeast Austin near the Austin-Bergstrom International Airport and is Austin Energy's most efficient and cleanest-burning fleet of gas-fueled generation. SHEC's efficiency and quick response capability allow Austin Energy to produce and sell energy to ERCOT as a revenue source to offset load costs. SHEC's proximity to Austin Energy's load zone provides value for customers by closely matching real time price exposure of load to generation pricing. SHEC offers both highly efficient combined cycle power production as well as quick start capabilities that protect customers from price volatility. The power plant is connected to three natural gas pipelines.

Construction began in October 2000 with four 45 MW General Electric (GE) LM6000 aero-derivative gas turbine generators. Those units began commercial service on June 20, 2001 and are valuable due to their ability to achieve full output in less than ten minutes. These turbines have fuel efficiency rates (heat rate) that are comparable to conventional steam units.

On September 1, 2004, a gas-fired combined-cycle unit went into operation at SHEC. This unit is currently a "one-on-one" configuration – that is, it includes one combustion turbine and one steam turbine generator. The gas turbine component is a GE 7FA with dry low NOx burners. The steam turbine is a GE D-11, with a heat recovery steam generator between these two turbines. When using duct burners, the combined cycle configuration can produce 300 MW. The steam turbine is sized to accommodate a second gas turbine, which would allow turning the configuration into a "two-on-one" configuration – meaning two gas turbines producing heat to operate the one steam turbine. This configuration would allow the unit to produce 500 MW and would slightly improve the efficiency of the overall plant. The primary cooling water for the combined cycle is provided by the adjacent South Austin Regional Water Treatment Plant. This reuse water application lowers the City of Austin's total consumption of Highland Lakes' water supply for its power operations.

In 2010, two additional LM6000 turbines rated at 45 MW each were installed at SHEC and went into commercial operation. These units have a slightly higher output than the older turbines due to improved inlet chilling system.

3.3.1.2. Decker Creek Power Station

Decker Creek is located in northeast Austin on Walter Long Lake. It consists of two gas-fired steam boiler generation units rated 321 MW and 405 MW, and four aero-derivative gas turbine units rated 50 MW each. Two of the gas turbines are contracted to ERCOT as “black start” resources, meaning that they can assist ERCOT with re-starting the grid in the event of an uncontrolled, system-wide blackout.

Decker Creek’s steam units were commissioned in 1971 and 1977, respectively, and the gas turbines were commissioned in 1989. The steam units are cooled by a reservoir (Walter Long Lake) that was built at the time of the original unit for cooling purposes.

The Decker Creek units provide revenue for Austin Energy customers to offset load costs incurred by AE to serve them. The Decker Creek steam units are older and less efficient than combined cycle technology; however, by carefully managing costs and running the units in the most flexible manner possible, Austin Energy retains these units in the portfolio as both a hedge and a revenue source to protect customers against strong market prices and to reduce Power Supply Adjustment costs. The total financial value of the steam units are closely monitored and any significant required spend above base O&M undergoes business case scrutiny. Maintaining exceptional reliability with prudent cost control is the key to providing customer value with the steam units.

The simple cycle (aero derivative gas turbines) at Decker Creek are Pratt & Whitney FT-4 designs and provide a real time price hedge, with quick start (less than 10 minute start to full load) capability. These units have a higher heat rate than the LM6000s at SHEC; however, they operate in a similar fashion. As more renewable generation sources enter the ERCOT market, quick start machines serve as a supportive technology to balance intermittency while protecting AE customers against price volatility.

Managing Decker Creek’s operations within the environmental permit limits is equally important. Plant personnel ensure environmental compliance by maintaining the continuous emissions monitoring system and operating boilers within procedures, testing and managing storm water and water discharge within permit limits, and maintaining spill containment and waste management programs.

3.3.1.3. Fayette Power Project

Fayette Power Project is a coal-fired facility near La Grange, Texas consisting of three pulverized coal units. The Lower Colorado River Authority (LCRA) and Austin Energy jointly own Units 1 and 2, while LCRA solely owns Unit 3. LCRA serves as the operator for all three units. Units 1 and 2 went into service in 1979 and 1980, respectively, and are rated at a capacity of 600 MW each. The units burn sub-bituminous coal from the Powder River Basin. FPP is cooled by water from Lake Fayette, which consists of water pumped from the Colorado River.

FPP Units 1 and 2 were fitted with new pollution control equipment in March 2011 that are capable of removing more than 95 percent of SO_2 emissions, and maintain FPP's position among the cleanest-burning coal plants in the state.

FPP provides low cost, dispatchable power for sale into ERCOT. The revenue from AE's ownership of Units 1 and 2 buys down the cost of energy that AE procures for load. FPP also adds valuable fuel diversity to the resource portfolio which protects Austin Energy from price spikes that can occur in the natural gas market. Additionally, FPP's value is enhanced by its relatively low emissions compared to many other ERCOT units of its age. FPP is in the process of being retrofitted with mercury controls equipment to further reduce its emissions during operation. This resource is well-positioned to continue benefitting Austin Energy's customers and to successfully dispatch into the ERCOT market.

3.3.1.4. South Texas Project

The South Texas Project is a nuclear power station near Bay City, Texas. The facility is located on a 12,220 acre site in Matagorda County, along the Gulf Coast. Austin Energy owns a total 16 percent share of STP Units 1 and 2, equating to roughly 400 MW of capacity. The facility is licensed and operated by the South Texas Project Nuclear Operating Company which, in turn, is owned by Austin Energy, NRG, and CPS Energy. The management and performance of the STP units has been good during the past two years, and the plant has achieved top quartile performance levels as measured by the Institute of Nuclear Power Operations in almost all areas. STP provides high capacity factor, low cost, zero-carbon emission generation for Austin Energy customers and continues to strive for higher performance levels.

STP has been a safe plant that has performed well. The past three years, under new leadership, STP has returned to high reliability performance. In 2014, Unit 2 at STP set the U. S. industry record for the highest total production from a single unit. The site has had 2 consecutive "breaker to breaker" operational runs meaning no outages between the planned 18-month refueling cycles. Focus areas for the site continue to be maintaining exceptional safety performance, reliable production, and cost control to deliver the highest value to the owners.

3.3.1.5. Renewable Power Purchase Agreements

Austin Energy currently has a number of Power Purchase Agreements for the purchase of renewable energy, including wind, solar, and biomass — both wood and landfill gas. These PPAs permit AE to continue to progress toward meeting the goals of the Generation and Resource Plan to 2025, which include an objective of obtaining 55 percent of customer energy needs from renewable sources by 2025. Costs associated with the renewable PPAs are reflected in the Power Supply Adjustment portion of customers' bills because the assets are neither owned nor operated by Austin Energy and therefore, are very similar to a market purchase from an economic perspective. Because the cost of AE's PPAs is recovered through the Power Supply Adjustment charge, they are not included in the base rate calculations.

As of December 2014, Austin Energy had the following PPAs in place:

Figure 3.7. Austin Energy's PPAs as of 2014

Renewable Resources	Fuel Type	Installed Capacity (MW)	Year Installed	Expiration Date	County
Biomass					
Sunset Farms	Landfill Methane	4	1996	2021	Travis, TX
Tessman Road Landfill	Landfill Methane	7.8	2003	2017	Bexar, TX
Nacogdoches Power	Wood Waste	100	2012	2032	Nacogdoches, TX
Total Biomass		*111.8*			
Solar					
Webberville Solar Project	Solar	30	2011	2036	Travis, TX
Total Solar		*30*			
Wind					
Sweetwater Wind Farm 2	Wind	91.5	2005	2017	Nolan, TX
Sweetwater Wind Farm 3	Wind	35	2006	2017	Nolan, TX
Whirlwind Energy Center	Wind	60	2007	2027	Floyd, TX
Hackberry Wind Project	Wind	165	2009	2023	Shackelford, TX
Penascal Wind Power	Wind	195.6	2010	2015	Kenedy, TX
Los Vientos IB	Wind	201.6	2012	2037	Willacy, TX
Whitetail Wind Energy	Wind	90.72	2012	2037	Webb, TX
Total Wind		*839.42*			
Total Renewable Resources		**981.22**			

These PPAs provide Austin Energy with renewable power supplies at costs less than could be obtained by Austin Energy constructing and operating these assets itself. This dynamic is due to the existence of federal tax incentives that can only be utilized by taxable entities, and which would provide no benefit to Austin Energy. The following subsections describe the general characteristics of the various renewable resource PPAs in place as of the end of FY 2014.

3.3.1.5.1. Wind

Austin Energy has a variety of PPAs for wind power from different producers and facilities. Austin Energy's wind power procurements have resulted in competitive pricing for this renewable energy and allow AE to progress towards the renewable energy goal established in the Resource Plan. Each wind PPA was acquired through a request for proposal process and reflects competitive and reasonable market prices for a resource of its type at the time acquired. The majority of contracts provide for a fixed price over the term of the agreement. In addition to the capacity reported above, nearly 500 MW of new wind capacity came online in 2015, and Austin Energy is working on bringing another 200 MW of contracted wind power online.

3.3.1.5.2. Solar

As of the end of 2014, Austin Energy had a PPA for solar power for the Webberville Solar project. In April 2014 Austin Energy signed a contract with Recurrent Energy to purchase 150 MW of solar energy, which is scheduled to be online and operational in 2016. More recently, Austin Energy began negotiating and executing contracts for up to 450 MW of additional solar PPAs, scheduled to become operational by the end of 2016 and into 2017.

These solar projects are reasonable additions to AE's resource portfolio in several respects. Solar power generation technology has matured and become more affordable in recent years and is based on well understood and widely used photovoltaic technology. Solar resources provide energy during peak demand periods, and the Webberville facility is proximate to AE load and therefore less prone to congestion risk. The contracts were acquired through separate request for proposal processes and reflect competitive and reasonable market pricing for a resource of its type at the time acquired. The contracts also offer price certainty for terms between 15 -25 years, diversify AE's resource portfolio, and support achievement of AE's renewable goals.

Despite the recent signing of contracts for several hundred MW of solar PPAs, the proposed rates do not include PPA contract costs for projects that were not yet operational in 2014.

3.3.1.5.3. Biomass

Austin Energy has two operational PPAs for landfill gas biomass power and one operational PPA for wood-waste biomass power. The Sunset Farm project provides pricing that is indexed to AE's overall fuel cost while the Tessman Road contract provides for a fixed price over the term of the agreement. The agreements put AE on a path toward meeting the renewable energy goals established in the Resource Plan and provide a consistent and controllable renewable resource.

3.3.2. Conclusion

Austin Energy maintains an exceptionally diverse power generation portfolio. The diversity of resources allows Austin Energy to benefit from the attributes of the various sources — from carbon free wind, solar, and nuclear, to clean burning, efficient quick starting natural gas, as well as solid fueled resources to mitigate risks associated with the global natural gas market. Locational diversity also provides Austin Energy customers more price control, by not placing all generation in a single location in ERCOT. Assets in close proximity to the load provide the highest real time price control opportunity, while resources in other areas of ERCOT provide advantageous characteristics (i.e. wind and solar production profiles that maximize value).

The solar and wind renewable PPAs provide value for customers, and through their long term fixed prices they provide future hedging value in addition to their renewable attributes. While the biomass PPA struggles with competitiveness in the current low natural gas price energy market, given its long term nature it may also provide hedging value with the added benefit of predictability if the Clean Power Plan or a similar regulatory approach to carbon management is adopted.

Generation resources afford Austin Energy the ability to earn revenue, set policy direction and make portfolio decisions that benefit AE customers, advance community climate goals, and support overall ERCOT generation and reliability performance.

3.4. MARKET OPERATIONS

Austin Energy's Energy & Market Operations (EMO) unit is responsible for all utility activities related to the electric wholesale market, fuel and purchased power procurement, and long term resource planning. On the operational side, EMO is the group primarily responsible for interacting with ERCOT real-time and day-ahead commercial operations, including the dispatch of power production and energy purchases to serve load. Within EMO are three work groups: Electric Operations and Risk Management, Market Analysis, and Market Systems. Below are brief descriptions of the scope and activities of each of these work groups.

3.4.1. Electric Operations and Risk Management Work Group

The Electric Operations function provides the primary interface between AE's load and generation resources and ERCOT. It functions as AE's Qualified Scheduling Entity (QSE), a necessary function as only QSEs registered with ERCOT may interact with ERCOT regarding generation, load, and other issues. For example, only QSEs may submit offers on behalf of generation resources or bids to buy wholesale power on behalf of customer electric load. QSEs are also responsible for submitting a Current Operating Plan for all generation resources that the QSE represents and offering or procuring ERCOT ancillary services as needed to serve their represented load. Finally, QSEs are responsible for settling financially with ERCOT, and serve as the contact point between Austin Energy and ERCOT for financial net settlement. Austin Energy's QSE is a Level 4 QSE which is the highest level and indicates that the QSE is qualified to represent Load Serving Entities and/or Resource Entities and provide Ancillary Services.

In its role as QSE, the Electric Operations group includes a 24/7 Real Time Operations Desk and a Day-Ahead Desk, assigning personnel who can interact with ERCOT 24 hours a day, 7 days a week. Austin Energy has eight individuals who work on a shift basis to ensure that this requirement is met. Austin Energy has two people on duty at all times, available to answer ERCOT inquiries, maintain ongoing current operations, and make changes to those operations to reflect new conditions as appropriate.

Austin Energy's Day-Ahead Desk participates in the formal Day-Ahead Market (DAM) facilitated by ERCOT as well as the bilateral day-ahead market. The goal of this group is to obtain the best wholesale supply price for AE's load while optimizing the value of AE's generation resources. Overall, the Day-Ahead Desk's main focus is protecting AE's customers against the effects of volatility in the wholesale energy market.

Electric Operations also includes a Gas Desk that supports daily gas purchases and scheduling. Its function is similar to the Day-Ahead Desk described above, only directed toward natural gas purchases. While the ERCOT DAM is occurring, the gas market for the next day is also trading. Natural gas is procured daily, since AE's gas needs vary significantly day to day and by plant. The Gas Desk participates in the bilateral contract day-ahead market for natural gas to procure the necessary quantities and schedule its delivery on the appropriate pipeline.

The second function within the Electric Operations and Risk Management team focuses on energy supply and risk management. This function is responsible for arranging AE's intermediate and long-term fuel and power supply contracts. This activity includes procurement and management of long-term power purchase agreements, fuel supply, and fuel transportation agreements. It does so in a manner consistent with the renewable energy goals set forth in the Resource Plan. Every market participant that operates power plants must procure fuel for them, and AE must do so as well. This highly specialized group is also responsible for conducting AE's energy risk management program which manages price risk associated with fuel and power supplies.

3.4.2. Market Analysis Work Group

The Market Analysis group provides analytical support to the other EMO work groups as well as AE as a whole. In particular, this group maintains and operates the UPLAN nodal network modeling tool. UPLAN is a commercial software tool used to estimate costs and revenues in the ERCOT market associated with AE load and resources. UPLAN modeling supports several activities at AE, including short to long term operations, transaction evaluation, resource planning, asset evaluation, budgeting, and rate estimation. With respect to resource planning, an important function of this group is to ensure that AE has accurate ERCOT system load forecast studies that model when generation may be needed most. This activity helps AE's plant managers correctly plan maintenance schedules, hoping to ensure that all resources will be available when conditions indicate a higher probability of high market pricing events. This group employs individuals with the specific expertise needed to develop cost projections to support budget and rate development.

3.4.3. Market Systems Work Group

The Market Systems group acquires, develops, and manages software and associated hardware that directly supports wholesale energy market operations. These systems include commercial and self-developed applications that are used to perform all aspects of QSE functions as described above. These applications include a generation management system and market interfaces for sending and receiving ERCOT data for operational and settlement purposes. This group provides the specialized market and systems knowledge necessary to sustain ongoing operations and to remain qualified as an ERCOT QSE.

3.4.4. Conclusion

The EMO team is an integral piece of the value proposition that the utility offers its customers. They are actualizing the benefits of the efficient wholesale market for AE customers. This team helps protect customers from escalating Power Supply Adjustment costs by maximizing value from AE's generation fleet, pursuing the renewable energy goals of the community, and bringing the associated cost and revenues together in overall affordable energy prices.

3.5. ELECTRIC SERVICE DELIVERY

Austin Energy delivers electricity to homes and businesses through a series of transmission and distribution lines. Austin Energy operates 634 miles of high voltage transmission lines (defined as 69 kilovolts and above) and more than 11,000 miles of distribution lines (defined as less than 69 kV). The utility has 14 transmission substations, 60 distribution substations, more than 76,000 transformers, and approximately 145,000 poles. AE spends more than $60 million each year maintaining and upgrading its distribution system.

It is important to recall that the PUCT has exclusive jurisdiction over rates and terms and conditions for the provision of transmission services in the ERCOT region, including those offered by Austin Energy. The PUCT sets the rate Austin Energy, as a Transmission Service Provider, is paid by users of the transmission system and the rate Austin Energy pays for its share of the remaining statewide transmission costs. This “open access” transmission system enables equal access to power for consumers located anywhere in the 90 percent of the state managed by the ERCOT ISO. Because the PUCT has regulatory authority over these Transmission Cost of Service (TCOS) rates, this report does not include a detailed description of Austin Energy’s transmission service, nor does Austin Energy’s proposal include any revenue to recover its transmission-related expenses. Instead, Austin Energy recovers the cost to pay for its use of the state’s transmission service through the Regulatory Charge. The pass-through Regulatory Charge is set each year through the City’s annual budgeting process, reflecting adjustments made by the PUCT to the TCOS matrix, and ensuring that Austin Energy collects revenue sufficient to pay other Transmission Service Providers for its use of the system. As a pass-through charge, Austin Energy does not collect a profit on the Regulatory Charge.

Austin Energy does include in this report, however, costs and revenues associated with building and maintaining its distribution system. The Electric Service Delivery (ESD) business unit is responsible for planning, engineering, design, construction, maintenance, and operation of AE’s transmission, substation, and distribution infrastructure. ESD’s main goals are to deliver electric power to customers; plan, design, construct, operate and maintain electric service delivery infrastructure, operating systems, and equipment; meter energy moving through the AE system; and restore electric service to AE customers when there is a disruption.

The electric distribution grid throughout AE’s 437 square mile service area supplies energy to Austin Energy’s customers. AE’s distribution system is the portion of utility’s electric transmission and distribution (T&D) grid that operates at less than 69 kV. As of September 30, 2014, AE owned and operated a distribution system of 387 circuits that served residential, commercial, and industrial customers. In 2014, the feeders were served from 60 distribution substations owned and operated by AE. Austin Energy also has about 150 large power substation transformers. Additionally, the feeder system spans 5,450 miles of overhead lines and 6,279 miles of underground lines, providing retail service throughout the AE service area. The majority of the operating voltages of AE’s overhead distribution feeders are 12.5 kV. The downtown underground network is served by 35 kV and 12.5 kV feeders.

ESD is comprised of six work groups: (1) Distribution Services North; (2) Distribution Services South; (3) Transmission and Distribution Planning & Regulatory Analysis; (4) Transmission and Substation Engineering and Construction; (5) ESD Support Services; and (6) Smart Grid and Systems Operations. Because the proposed rates do not include costs associated with transmission services, the following sections will detail ESD's vital distribution level work in ensuring reliable and safe operation of Austin Energy's distribution system.

3.5.1. Distribution Services North & South

The two Distribution Services units are responsible for the engineering, design, heavy maintenance, and construction of infrastructure in Austin Energy's service territory. Austin Energy divides its service area into a north territory and a south territory for operational purposes. The dividing line between north and south is approximately along the line (from east to west) of FM 969, MLK Boulevard, and the Lower Colorado River (or the Highland Lakes that continue to the River).

The primary functions of the two distribution services work groups include Engineering and Design, Overhead Construction including Street Lights, Work Management, and Network Construction.

Engineering & Design employees interface with customers to assess their electrical service requirements and prepare cost estimates for the required services. They also prepare material and equipment requests and design drawings according to detailed design and construction standards to make the additions, modifications, or maintenance repairs to the distribution system requested by the customer or necessitated by maintenance, failure, or damage.

Overhead Construction consists of service and heavy construction crews, contractor inspection services, large equipment, and instrument testing and calibration groups. They provide the following services:

- Service crews provide installation, removal, and repair services for street lights, overhead transformers, and other related tasks that do not require work at more than one work point or heavy equipment.
- Heavy Construction crews run larger jobs typically with multiple work points to install, remove, and repair poles, large overhead equipment, underground primary cable, padmount equipment, switchgear, and distribution vault equipment.
- Contractor Inspection Services oversees the work to be completed by contractors to be sure that customer schedules can be met or that necessary system improvements are

completed in a timely manner. They schedule the distribution projects to be performed by contractors and provide qualified inspectors to track and ensure the work is conducted to Austin Energy requirements.

- The Large Equipment group maintains an equipment yard for large padmount transformers, padmount switchgear, steel poles, and other large or specialty equipment, as well as the personnel and equipment to install some of these items.

- Instrument Testing and Calibration group coordinates testing or repair of the tools and instruments used in delivery of service by distribution staff and others to assure the quality and reliability of service.

Work Management coordinates with all parties to ensure work projects are scheduled and readied for construction. This group handles the ordering of materials specified by Engineering and Design and assigns and schedules jobs to be completed by Austin Energy crews as well as determines which jobs will be assigned to contractor construction crews. This group also inspects the civil infrastructure installed by the customer to be sure it meets the requirements for Austin Energy underground and padmount facilities. Following completion of the job, Work Management personnel close out the jobs and provide as-built prints to record how the job was constructed.

The Network Construction group installs and maintains the underground electrical networks in the downtown area, including secondary and primary cable.[47] This group is also responsible for installing and maintaining all underground power cable used for substation feeder exits and risers, including direct power cable feeds from a substation to large industrial customers, like a water treatment plant.

3.5.2. <u>Transmission and Distribution Planning & Regulatory Analysis</u>

Whereas Distribution Services work on the system of today, Austin Energy's Transmission and Distribution Planning & Regulatory Analysis group is responsible for ensuring that there will be adequate transmission and delivery capacity in the future. Additionally, the group provides regulatory and compliance support for ESD to ensure compliance with ERCOT and NERC reliability regulations. T&D Planning & Regulatory Analysis is necessary for AE's operations to ensure that the utility will have sufficient infrastructure to provide electricity reliably to its customers at a reasonable cost during both normal and contingency conditions.

The distribution planning cycle typically begins at the start of a new fiscal year in October after the publication of the ESD plan book. The plan is ESD's strategic document that describes system

[47] The downtown network is the area bordered generally by West Avenue, I-35, Martin Luther King Jr. Boulevard and Barton Springs Road. There are some extensions that run as far north as 27th Street and some as far west as Bowie Street.

improvements needed for successful operation for the next five years. The planning process begins with a review of the distribution system performance during the previous summer's peak load periods. Overhead distribution feeder circuits and substation transformers are noted for further study when their loading reaches 85 percent of their normal rating under normal (i.e. all facilities in service and all loads being served) conditions. The downtown underground network feeders are also reviewed in a similar manner.

Austin Energy distribution planners use the ABB FeederAll distribution system modeling package to analyze the distribution system. To ensure model accuracy, they first match and then test the previous summer's system configuration and peak load conditions. Load growth for the substations and feeders selected for further study is determined and modeled for the following five-year period. Load growth projections are developed using information obtained from plat review meetings, the Public Involvement and Real Estate Services Subdivision/Site Plan database, Key Account representatives, and other ESD divisions including, Distribution Services North& South, System Operations & Reliability, etc. Distribution planners also consult the economic outlook and system load forecast for the Austin Energy service territory prepared by the Finance business unit.

The updated ABB FeederAll model is then tested to evaluate loading and voltage drop for each feeder and substation unit transformer under both normal and contingency conditions. If the model identifies Austin Energy Distribution Planning Criteria violations, additional analysis will be conducted to develop recommended system improvements needed to solve the identified problems. Once an improvement is approved by ESD management, it will be included as a proposed project in the development of the next Capital Improvement Plan budget.

3.5.3. ESD Support Services

In addition to planning, engineering, and construction of the distribution system, ESD has various programs that are included in vital operations and maintenance strategies. Some of AE's major programs include: (1) Vegetation Management; (2) Quality and Emergency Response; and (3) Street Light Maintenance.

3.5.3.1. Vegetation Management

Austin Energy maintains the vegetation around its facilities to provide worker and public safety and reliable electric service. Austin Energy operates numerous programs such as: overhead line clearing; substation vegetation control; storm and trouble response; and capital improvement projects.

In accordance with the National Electric Safety Code requirement to maintain vegetation around our electric facilities, AE maintains the vegetation around its 5,450 miles of overhead lines on a routine cyclical 4-5 year basis. Austin Energy also maintains the vegetation in and around its 60 substations to control the weeds and grass in the graveled areas. Additionally, Austin Energy maintains the area outside of the substation in a manner that comports with neighborhood aesthetics. The gravel areas are treated once or twice a year for weed control and the landscaping outside of the substation is maintained as needed. Austin Energy also performs tree pruning and removal as a part of our storm and trouble response and restoration.

3.5.3.2. Quality and Emergency Response

Austin Energy's emergency restoration plan for handling disasters that affect the AE system is modeled after the National Incident Management System (NIMS) plan. NIMS enables responders at all levels to work together more effectively and efficiently to manage domestic incidents no matter the cause, size, or complexity, including catastrophic acts of terrorism or natural disasters. As part of the City of Austin, Austin Energy is able to maintain contact with local, county, state, and federal entities to ensure we are ready in the event of a disaster. Austin Energy maintains the emergency plan and makes improvements based on lessons learned from emergency events and exercises.

Austin Energy maintains an emergency response plan for both ERCOT Energy Emergency Alert (EEA) events as well as the Black Start Emergency Plan. EEAs occur when the ERCOT grid becomes unstable due to an unforeseen loss of generation supply or an unexpectedly large spike in demand for electricity. The imbalance between supply and demand causes the system frequency to fluctuate, and if left unchecked, can cause a cascade of outages on both the generation side and the transmission side. ERCOT uses EEAs to roll outages across the entire system (brownouts) thereby avoiding a catastrophic system-wide electrical outage (blackout). A section of Austin Energy's Emergency Response Manual specifically deals with EEA events. Using NIMS, Austin Energy has a plan to address both response and crisis communication during an EEA event. This plan is reviewed annually.

Additionally, Austin Energy is an ERCOT-certified Black Start Utility. In the event of a widespread blackout, ERCOT can restore the Texas electrical grid through the start-up of generation resources that do not have to rely on the ERCOT transmission system to come online. Under normal circumstances, the electricity used at a power plant is provided from the station's own generators or by drawing power from the transmission grid. However, during a blackout, neither generator- nor grid-supplied electricity will be available, rendering the power plant incapable of operation. In the absence of grid power, some power stations have black start generators, which can be used to start the main power station generators absent other sources of electricity. Decker Creek Power Station is certified to provide this vital function and Austin Energy earns revenues for the important service provided by this older plant. The Black Start plan is reviewed by Austin Energy annually and tested by ERCOT on regular intervals to ensure compliance and readiness.

3.5.3.3. *Street Light Maintenance*

The Austin Energy Street Light Group is responsible for installing and maintaining street lights in Austin Energy's service territory and for all City of Austin-owned outdoor lighting. Austin Energy is also under agreement with the Texas Department of Transportation (TxDOT) to provide energy and maintenance to lighting along TxDOT roads and highways in the Austin Energy service territory. Austin Energy designs, constructs, and maintains approximately 65,000 lights that are classified as either a street light or City-owned outdoor lighting within the AE service area. Austin Energy expects this number to increase due to new housing developments, continuing requests for street lights, and annexation of surrounding areas.

In all, the ESD business unit serves as Austin Energy's front line that ensures continuous and reliable electric service to Austin Energy's customers now and in the future. Many times, ESD employees have to perform this work in the cold of a winter night or in the middle of a torrential downpour to restore service to customers as quickly as possible after an unplanned outage occurs. Other times, the work is conducted in training sessions or compliance meetings that infuse industry and utility standards throughout the myriad work groups. But all together, ESD creates significant value for Austin Energy's customers by ensuring service is there when it's needed or restored as quickly as possible when the unforeseen occurs. One way Austin Energy measures this value is by evaluating the reliability of service provided to its customers.

3.5.4. Smart Grid and System Operations

This unit is comprised of Control Engineering and Complex Metering, among other work groups.

The Control Engineering work group is responsible for the procurement, installation, configuration, and maintenance of power automation systems including: the Supervisory, Control and Data Acquisition and Energy Management System (SCADA/EMS) and the Advanced Distribution Management System (ADMS). These systems are often viewed as analogous to air traffic control systems because they are used by Austin Energy to control the transmission, substation, and distribution power systems from either the primary or backup centralized control centers. Because they are mission critical, these systems are designed with redundancy to accommodate any component failure. Control Engineering is responsible for the continual maintenance of the specialized computers used to collect data and execute remote controls. The distribution system impacts nearly all AE customers and since going into service in 2014, the ADMS is the tool ESD uses to manage distribution level outages and restoration.

The Complex Metering work group is responsible for the company-wide:

- procurement, warehousing, testing and certifying, programming, and internal distribution of meters for field installation;
- installation and maintenance of all instrument transformer rated metering for commercial and industrial metering as well as for all bulk power generation and interconnection metering points for ERCOT;
- oversight of daily operations of vendor-provided advanced metering infrastructure services;
- meter installation inspection; and
- dispatch workforce management including the completion of customer information system updates.

Customer usage is measured at the customer's point of service by meters owned, maintained, and operated by Austin Energy. These include kWh meters for residential and small commercial users, demand meters that measure both kWh usage and the kW monthly peak demand for commercial customers, and time of use meters that record kWh and reactive power values — measured in kVARh — at different times of the day and seasons of the year. Austin Energy continues its partnership with Pecan Street, Inc., an innovative community research organization formed to develop a smart grid strategy for the future.

3.5.5. Measuring Reliability

Like all distribution service providers, Austin Energy measures its reliability of service by calculating two industry-standard scores: the System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). SAIFI is an indicator of how often the average customer experiences an outage over a given period of time. SAIDI is an indicator of the total duration of all interruptions experienced by the average customer over a given period of time. Better performance is represented by lower numbers in both metrics.

Every time an outage occurs, Austin Energy records two important pieces of information:

(1) the number of customers interrupted (CI); and

(2) customer minutes interrupted (CM).

The CM is calculated by the number of customers interrupted multiplied by the duration in minutes. Austin Energy uses two sources of data to gather this information. The first source is the Outage Management System, (OMS), which processes outages called in by AE customers. The OMS data is recorded in Oracle tables. The second source is a Microsoft Access database that is used to record circuit breaker operations at a substation. The System Engineering group is responsible for generating a Monthly Reliability Report. The group follows a documented Organization for Standardization 9001 (ISO 9001) process to produce the monthly report. The ISO 9001 process consolidates the data from both sources into one table.

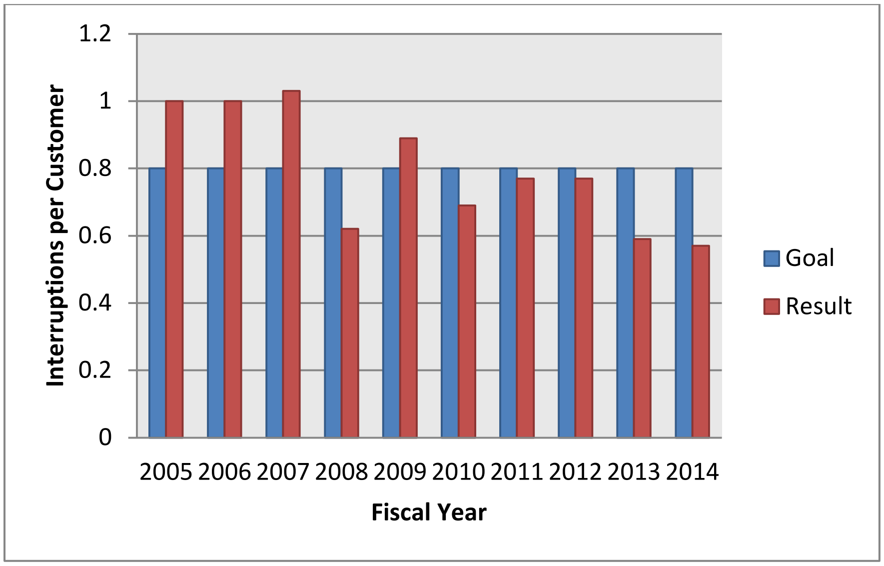
To calculate SAIFI and SAIDI, AE uses the ANSI calculation method that is defined in the Institute of Electrical and Electronics Engineers' (IEEE) Standard 1366, IEEE Guide for Electric Power Distribution Reliability Indices. The formulas are:

$$\text{SAIFI} = \Sigma \text{ Total Number of Customers Interrupted / Total Number of Customers Served}$$

$$\text{SAIDI} = \Sigma \text{ Customer Interruption Durations / Total Number of Customers Served}$$

Austin Energy's ten-year SAIDI and SAIFI results are provided in the following figures. The annual goal for SAIFI is 0.80 outages per customer. As Figure 3.8 indicates, AE has bettered its annual goal in six of the past seven fiscal years.

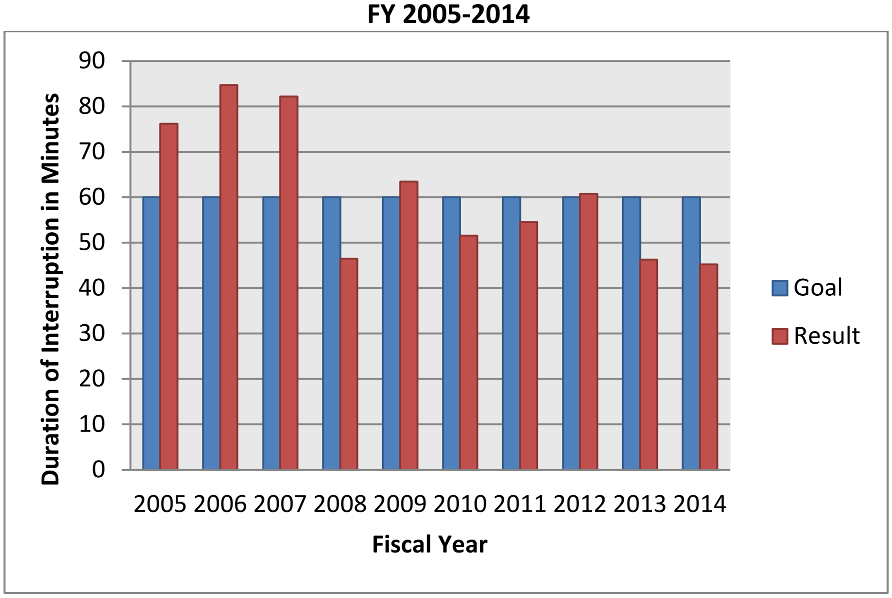
FIGURE 3.8. SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX FY 2005-2014



Additionally, Austin Energy's SAIFI scores rank the utility in the top quartile of electric utilities surveyed by First Quartile Consulting. Mean SAIFI scores in 2014 and 2013 for utilities surveyed by First Quartile were 0.97 and 1.00, respectively.

Austin Energy's annual goal for SAIDI is 60 minutes per customer. Figure 3.9 indicates that Austin Energy has surpassed this goal in five of the seven past fiscal years.

FIGURE 3.9. SYSTEM AVERAGE INTERRUPTION DURATION INDEX FY 2005-2014



Additionally, Austin Energy's SAIDI scores rank the utility in the top quartile of electric utilities surveyed by First Quartile Consulting. Mean SAIDI scores in 2014 and 2013 for utilities surveyed by First Quartile were 108.42 and 94.84, respectively.

First Quartile also places Austin Energy's operations and maintenance costs in the top 50 percent of utilities surveyed. In terms of cost per customer, cost per megawatt-hour, and O&M costs as a percentage of total assets, Austin Energy provides exceptional service at reasonable rates.

3.5.6. ESD Conclusion

The ESD organization touches customers at every phase. From a new customer perspective, they estimate, plan, and construct distribution infrastructure, and acquire necessary easements to power new buildings and subdivisions. Then they install meters and turn on the new service. As a long term provider, ESD manages outages and restoration, performs vegetation management, manages pole attachments, and continually assesses and improves the distribution system to assure long term reliability to all customers.

3.6. CUSTOMER SUCCESS

The preceding sections of this report addressed how Austin Energy manages its business and regulatory environments to create value for its customers, the City of Austin, and the residents of Austin. In essence, it described the industry facing side of AE's business practices. However, the utility has developed many customer-oriented programs — each designed to bring economic and community benefits to its customers. Whether through energy conservation, reduced emissions, or efficient customer service, Austin Energy's guiding principle is to make it easy for its customers to work with the utility and to provide them with products and programs they regard as valuable.

The following sections provide an overview of Austin Energy's customer-facing services, including programs in energy conservation, green building, solar, customer services, and account management.

3.6.1. Energy Conservation

Austin Energy is a national leader in developing and implementing programs that ultimately help its customers reduce or shift their consumption of energy and save money on their bills. In addition, the programs help Austin Energy reduce its need to buy additional sources of energy, thereby lowering the utility's exposure to the risks of the ERCOT wholesale market and reducing harmful emissions from fossil fuel-fired generation. Austin Energy's Customer Energy Solutions (CES) division is responsible for developing these energy conservation services that support the utility's goals and provide a valuable service to our customers. CES achieves these objectives in two major ways: through offering market-based incentive programs that encourage residential customers and businesses to retrofit existing buildings and install energy efficiency measures and through its Green Building program, which encourages builders and developers to meet high energy efficiency standards when designing new residential and commercial buildings. The Green Building program was the first of its kind in the nation and will celebrate its 25 year anniversary this year. The program promotes efficiencies through the award of voluntary efficiency ratings and through supporting the passage and enforcement of enhanced building codes.

Overall, Austin Energy's energy conservation goals reduce the amount of customer demand during summer peak periods and reduce the amount of energy either procured by Austin Energy or purchased through the wholesale market. These energy usage outcomes help customers in four distinct ways.

First, Austin Energy's programs improve the efficiency of residential, multifamily, commercial, and industrial buildings, reducing customers' overall energy consumption. Lower consumption results in a lower total bill because the cost of retail electric service is higher than the cost of the energy efficiency programs.[48] Austin Energy estimates the system-wide annual bill reduction benefit to be approximately $12.2 million per year, and these savings recur annually for the customer throughout the life of the efficiency measure. Additionally, the programs reduce the utility's total annual system demand, resulting in lower usage of the state's transmission system compared to other service areas. By using comparatively less of the ERCOT transmission system, transmission system access costs are reduced, allowing Austin Energy to minimize increases in the Regulatory Charge, a fee that is directly passed on to its customers.

Second, reducing customers' consumption of electricity decreases Austin Energy's need to procure energy, and as a result incrementally lowers Austin Energy's exposure to the risks of the ERCOT wholesale market. As discussed above, the highest average wholesale market prices tend to occur during the hot summer months and Austin Energy's demand side management programs directly lower demand for electricity during those summer peak hours. Using less energy when wholesale market prices spike reduces AE's need to buy electricity at costs that can be 200 times more expensive than the

[48] The weighted average life cycle cost of energy efficiency in FY 2014 was $0.0315 per kWh compared with an average residential retail electricity rate of $0.1197 per kWh (based on FY 2014 rates and average consumption of 920 kWh per month).

average. These strategies minimize volatility in the Power Supply Adjustment, another charge that is directly passed on to the utility's customers. In FY 2014 alone, the energy efficiency programs reduced Austin Energy's peak demand by 67 MW.

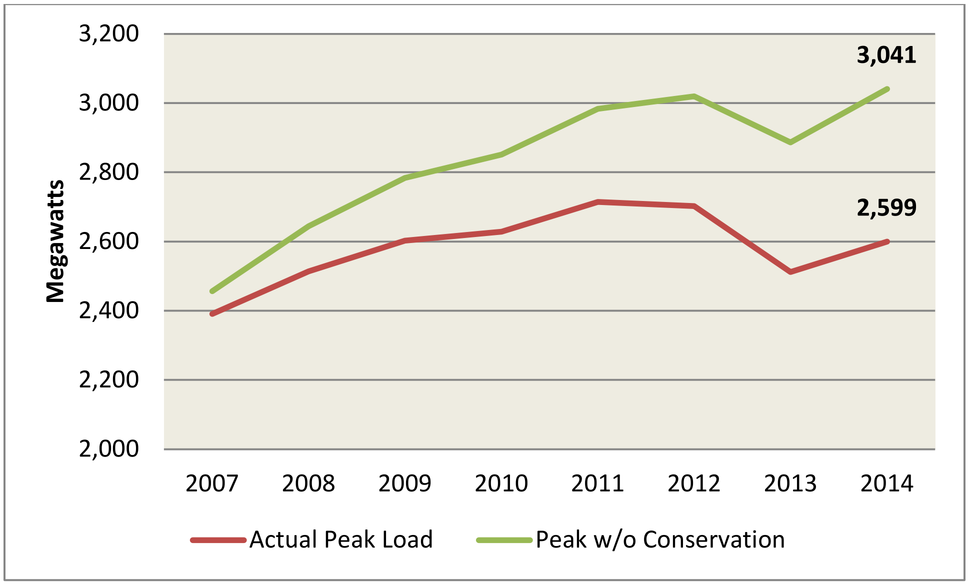
Third, energy conservation incrementally reduces state-wide power plant stack emissions, an important goal identified by the Austin community. With a goal of reducing 900 MW of demand on the ERCOT system from 2007 through 2025, Austin Energy's conservation programs result in fewer megawatt hours of generation that need to be dispatched in the real-time wholesale market, incrementally reducing the amount of fossil fuel-based emissions that are released. Assuming current rates of program adoption and of megawatt hours saved, Austin Energy would project more than 2,300 million pounds of CO_2 to be removed from Texas' air by the time the energy conversation programs achieve 900 MW of reductions.[49]

Fourth, Austin Energy's energy conservation programs have driven transformation in the energy management product market, resulting in the development of new products that increase customer comfort and satisfaction. For example, Austin Energy was one of the first utilities to launch a remotely-controllable thermostat program that allows the utility to cycle off customers' air conditioning load — with their permission — during high price events in the wholesale market. Fifteen years later, companies like NEST, Honeywell, and Ecobee are developing intelligent thermostats that provide the end-user and the utility with highly functional levels of energy management control that are easy to use.

As a result of these energy conservation programs, Austin Energy has been able to offset 441 MW of peak demand from 2007 through 2014. Figure 3.10 shows the impact Austin Energy's energy conservation programs have had on peak demand for the past eight years.

[49] Total is calculated on calendar year 2014 ERCOT system-wide average emissions rate of 1,235.9 lbs CO_2 per MWh and a projected 1.89 million MWh of energy savings in the year 900 MW of reductions are achieved. *See* ERCOT's 2014 Renewable Energy Calculator at www.ercot.com/mktinfo/retail/electric. These savings would reduce total ERCOT system-wide emissions by approximately 0.5 percent, based on ERCOT's Current Trends forecast for CO_2 emissions in CY 2021. *See* ERCOT, *2014 Long Term System Assessment for the ERCOT Region*, December 2014, pg. 74.

FIGURE 3.10. Cumulative Peak Demand Reduction
FY2007 – FY 2014



Austin Energy's energy conservation and demand side management programs are managed by the Energy Efficiency Services (EES) group which implements the Residential, Multifamily, Commercial, and Demand Response Demand Side Management Programs and the Energy Conservation Audit & Disclosure (ECAD) ordinance. These energy efficiency programs are promoted through the use of rebates and incentives, low-interest loans, energy audits, and the ECAD ordinance.

Austin Energy's Demand Side Management Programs provide energy management services by offering technical assistance and energy audits to both residential and commercial customers. EES staff helps identify efficiency opportunities, makes recommendations on the most cost-effective measures, and offers financial incentives for installations of qualifying energy efficient equipment.

During FY 2014 there were 10,369 residential participants, 8,485 commercial participants, and 5,810 demand response participants in the Power Saver™ Program. During the FY 2014, Austin Energy's residential, commercial, and demand response programs achieved a reduction of 6.9 MW, 16.4 MW, and 19.6 MW, respectively, for a total reduction of 42.9 MW. Additionally, Austin Energy achieved annual energy savings of 12,379 MWh for residential programs and 65,028 MWh for commercial programs.

Each of these programs plays an important part in achieving Austin Energy's energy efficiency goals. For example, Austin Energy has designed innovative direct install programs for markets like small businesses and multifamily properties that have traditionally been harder to serve in energy efficiency programs. These markets each have barriers to improving their energy efficiency due to limited access to capital and split incentive billing structures. Also they often lack the resources or expertise to choose appropriate energy efficient products and designs, and to manage their implementation. By incentivizing these customers with higher rebates and using registered and trained trade allies to provide expertise, process management, and quality installations, these markets are being served more capably than ever before. In 2014, the Small Business program served over 500 small businesses and reduced peak demand by 3.4 MW, while the Multi-Family program served almost 9,000 apartments and reduced peak demand by 3.9 MW.

3.6.2. Green Building

The Austin Energy Green Building group (AEGB) provides technical assistance and educational services to building owners and industry professionals seeking to build resource-efficient structures that protect and improve the quality of life in the greater Austin area. AEGB rates new construction and major renovations for single family, multifamily, and commercial projects as well as offers performance modeling support. AEGB is also responsible for the adoption and implementation of the City's Energy Code. City inspections are funded by AEGB to ensure that new construction plans are in compliance with the City's Energy Code.

All homes within Austin Energy's service area are eligible to receive AEGB and National Green Building Standard certification ratings through Austin Energy. Additionally, all Austin Energy customers have access to AEGB programs such as monthly professional development seminars, Green by Design workshops, Green Boots — builder and trade contractor education series, realtor training, and the annual Cool House Tour. Additionally, AEGB creates events and produces publications to celebrate achievements and educate the community. A monthly digital newsletter features AEGB ratings guides, a directory of green building professionals in the service area, and case studies of rated buildings in the Austin area to showcase real world applications of sustainable building practices.

In FY 2014, AEGB rated 19 commercial projects and reported three Leadership in Energy and Environmental Design (LEED)[50] projects. These projects account for nearly 3.8 million square feet of new construction/major renovations and include 1,618 residential units in buildings over six stories. In residential buildings less than seven stories, AEGB rated 13 multifamily projects containing 2,067 dwelling units and 729 single family homes. During FY 2014, AEGB achieved annual peak demand

[50] Leadership in Energy and Environmental Design is the green building standard monitored by the U.S. Green Building Council.

reduction of 24.6 MW and an annual energy savings of 52,456 MWh. Demand and energy savings for the years 2010-2014 are shown in Figure 3.11.

Figure 3.11. AEGB Energy & Demand Savings FY 2010-FY 2014

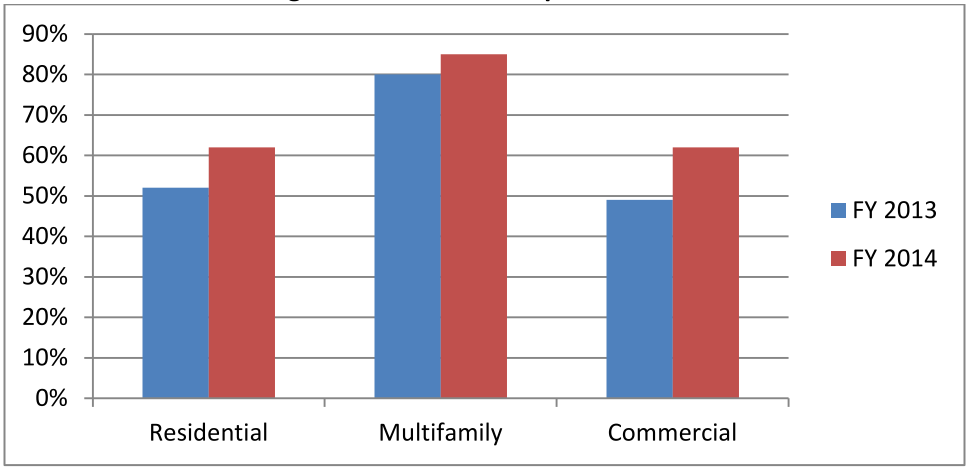
Year	Energy (kWh)	Peak Demand (kW)
2010	16,577,170	7,469
2011	25,739,213	9,634
2012	26,871,940	11,900
2013	46,222,361	17,998
2014	52,455,769	24,610

3.6.3. Energy Conservation Audit & Disclosure

The City of Austin was the first municipality in the country to adopt an energy disclosure ordinance for all three market segments: single family residential, multifamily, and commercial. The ECAD ordinance was initially approved by City Council in 2008 as a cooperative effort between City staff, local real estate professionals and community leaders that requires audits and disclosures for existing homes and buildings served by Austin Energy and located within the Austin City limits. Disclosure of the energy efficiency of a building at the time of its sale enables new owners of residential homes, multifamily properties, and commercial buildings to plan future steps that will improve the building's energy performance and lower operating costs.

The ECAD ordinance's phased implementation began more than six years ago. In 2009, residential home administrative rules were first introduced requiring home sellers to provide energy audits at the time of sale for homes more than 10 years old. Since then, more than 22,000 homes have performed and disclosed an energy audit. Multifamily properties joined the program in 2010, with owners required to conduct an audit at least once every ten years and for properties that are more than 10 years old. More than 850 multifamily properties receive annual Multifamily ECAD Energy Guides used by property management in the lease application process with potential residents representing an 85 percent compliance rate for multifamily properties. Beginning in 2012, Austin launched a phased implementation plan for annual energy benchmarking for commercial buildings larger than 10,000 square feet. Figure 3.12 shows the compliance rates for each building sector for FY 2013 and FY 2014.

Figure 3.12. ECAD Compliance Rates



3.6.4. Solar

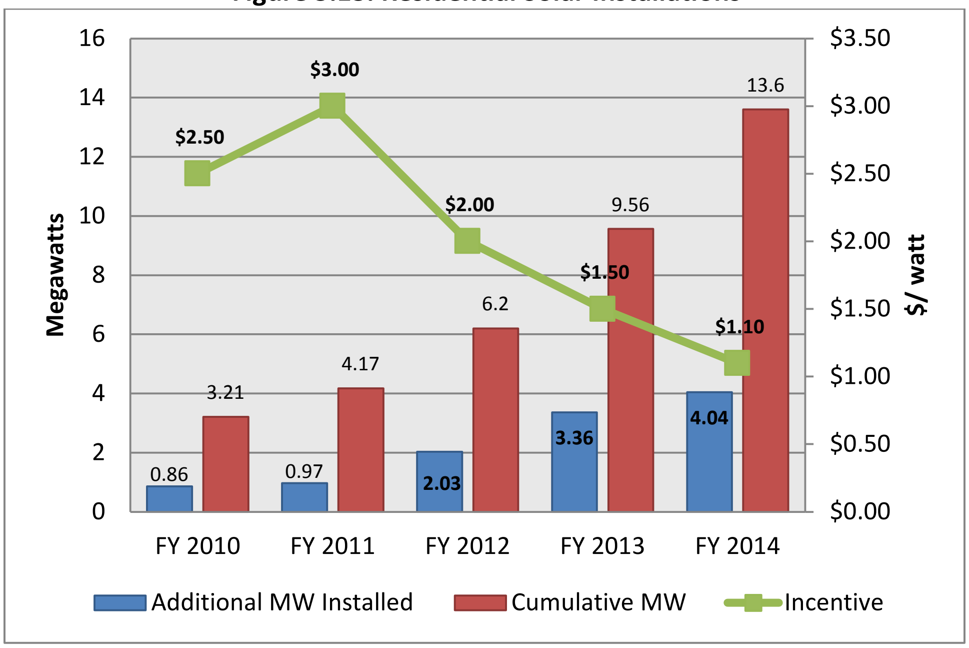
Similar to its energy conservation programs, Austin Energy provides a suite of solar programs that offer economic and community benefits to its customers. In many instances, customers can reduce their electric bills and provide locally-sourced, renewable energy that incrementally decreases Austin Energy's reliance on fossil fuel-based generation and its use of the state's transmission system. The solar group in CES develops and implements programs that are highly valued by many in Austin Energy's community.

Austin Energy offers incentives to encourage its customers to install solar photovoltaic (PV) energy systems at their home or business. Residential customers may be eligible to receive a rebate on the cost of installing their solar PV system, and may be eligible to receive Value of Solar (VOS) credits for all the energy generated by their solar PV system under current residential electric rates. Commercial customers may be eligible to receive a Performance-Based Incentive (PBI) that provides approved participants an incentive payment for each kilowatt-hour of energy produced by the customer's system for a 10 year period, on top of the customer's electricity bill savings thanks to reduced consumption of grid power.

Residential rebate amounts are set on a dollar per watt basis and are used to help customers overcome the significant barrier to entry of upfront installation costs many consumers face. In order to qualify for a solar PV rebate, residential participants must also meet energy efficiency requirements, including having participated in Austin Energy's Home Performance with ENERGY STAR program or Free Home Improvements program, have an AEGB 5-Star rating, be in a home less than 10 years old, or obtain an actionable bid for energy efficiency improvements. If the residence meets all other program requirements, such as solar access requirements, and if funding is available, Austin Energy issues a letter of intent to the customer, who then can have the PV system installed by a participating energy installer.

As more systems have come online in the past five years, installed system costs have declined steadily, allowing Austin Energy to reduce rebate levels proportionately. Despite the periodic drops in the rebate level, the annual rate of solar PV installation has continued to increase markedly since the program's inception in 2004. Figure 3.13 shows the five year history of rebates levels and installations.

Figure 3.13. Residential Solar Installations



Residential solar customers also receive the VOS credit on their electric bill for the electricity produced from their solar PV system. Under the rate structure, a solar PV customer will pay for their total gross energy consumption at the standard residential rate applicable to their consumption level. Austin Energy will then credit the customer for the total solar production at the annually calculated VOS rate. The VOS rate is calculated using an avoided cost methodology that takes into consideration the value of the energy produced based upon the marginal cost in the ERCOT market of the displaced energy, the avoided capital cost of building new power generation due to the added capacity of the solar PV system, transmission and distribution expense and line loss savings associated with the system, and environmental benefits. The credit level is adjusted annually to account for market value changes and other factors that influence the value of the solar energy generated. In 2014, the VOS rate was 10.7

cents per kWh of energy produced, and beginning January 1, 2015 the VOS rate was set to 11.3 cents per kWh.

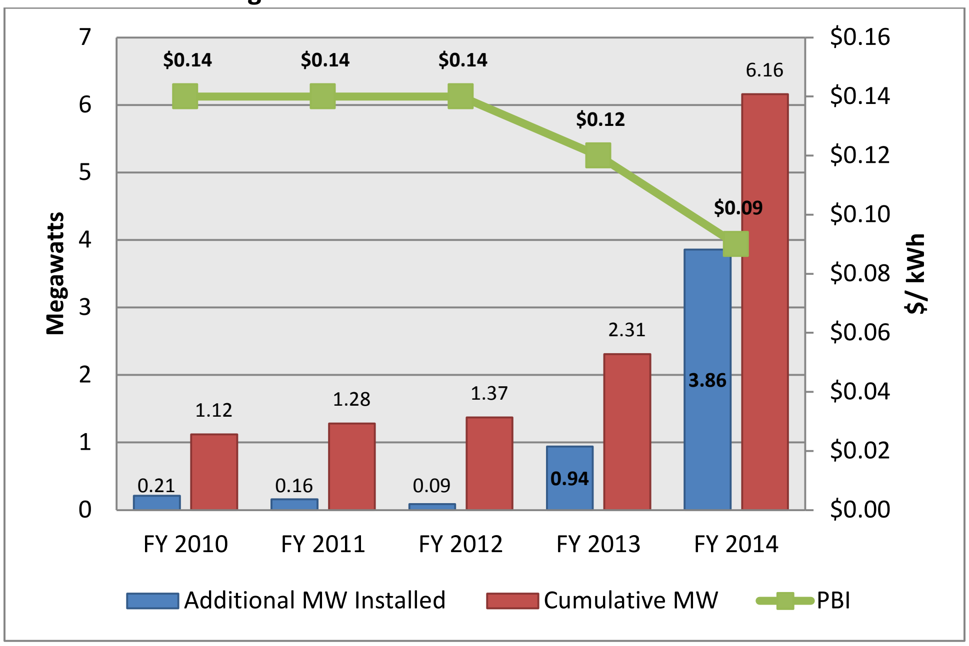
Austin Energy switched to the VOS in 2012 to better align solar program incentives with utility and customer outcomes, especially as compared with the more traditional model of net metering. For example, because the same VOS rate is applied to all residential solar customers regardless of their rate of consumption, equity among solar customers is dramatically improved. In essence, VOS decouples the value of the solar generation from customer's consumption behaviors. In contrast, under net metering, customers' solar "value" is determined by what tier consumption their production is offsetting, thereby providing a larger benefit to customers who consume more energy on a monthly basis. Further, VOS reduces cross-subsidization by non-solar customers due the methodology that determines the VOS rate. The costs of local solar generation can be compared more closely to energy that would otherwise be bought from the wholesale market and the VOS results in a more revenue-neutral impact to the utility and its customers as compared with net metering.

Unlike residential customers, commercial customers do not receive an upfront rebate. Rather, commercial customers may apply for Austin Energy's PBI program, which provides an incentive based on the actual energy produced by the commercial PV system.

The solar PBI program is designed to support the local solar market and help commercial property owners implement solar PV technology by offering incentives based on the electrical output of the installed PV system. The PBI program is specifically designed to reward system design optimization, long-term system maintenance, and long-term operations. As of FY 2015, customers who participate in the PBI program receive a credit of anywhere between \$0.02 and \$0.14 per kWh for the production of electricity from their solar PV system for a term of ten years, with the incentive level determined by the system size, and the amount of previously installed capacity at the time of their application. Incentive levels decrease over time as more capacity is installed through the program, and larger systems receive smaller incentives as they are able to achieve better installed prices due to economies of scale. Systems must be less than 1 MW in size to take part in the program. The PBI credit is calculated by multiplying the kWh production of the PV system by the customer's approved PBI rate, and appears on the participant's electric bill each month. Additionally, the solar production from the PV systems offsets building energy consumption, lowering the electric bills for commercial solar customers. For commercial PV systems less than 20 kW, any excess energy generated from the solar PV system is also credited at the current fuel cost rate and further offsets their grid consumption. Commercial customers who participate in the PBI program are billed for electricity delivered by AE at their applicable rate for their customer class.

As with the residential solar program, Austin Energy has decreased the incentive amount as installation costs have declined, and similarly, participation in the program continues to grow, with annual capacity installations increasing. Figure 3.14 shows the five year history of PBI rates and installations.

Figure 3.14. Commercial Solar Installations



As of September 2014, AE supported 3,477 residential customer-owned solar energy systems, 191 commercial projects, more than 50 municipal projects and 32 school installations that provided more than 22.5 MW of generation capacity. This renewable energy production results in lower bills for Austin Energy customers, decreased power supply costs for Austin Energy, and incremental environmental benefits through lower reliance on fossil fuel generation and water consumption.

3.6.5. Customer Care

As a public power utility, part of Austin Energy's mission is to provide easy-to-use services that its customers value. While the generation, transmission, and delivery divisions are critical functions of the utility, most customers only interact with AE's Customer Care division. In recognition of this important fact, AE strives to provide excellent support services to all of its customers with quick, courteous, and complete follow-through on their requests and needs.

To ensure that all customers receive the attention and support they need and deserve, the Customer Care division consists of six different work groups: (1) Utility Contact Center (UCC); (2) Customer Service Management; (3) Citywide Information Center (Austin 3·1·1); (4) Billing Services; (5) Revenue Measurement & Control; and (6) Quality Management (QM). Together, these work groups provide support services that are necessary for AE to provide electric service to its customers. They allow customers to start, stop, and transfer service. They permit customers to get answers to their myriad questions about billing, service, and other issues. They provide information about AE programs, including GreenChoice, levelized billing, electronic funds transfer, customer assistance, and energy conversation programs, and they enable AE to generate bills and collect the funds necessary to run the utility.

3.6.5.1. Utility Contact Center

The Utility Contact Center is the primary informational interface between AE and its customers. To better serve the diverse needs of the various classes of customers, the UCC is divided into four distinct units including Residential Contact Center, Commercial Contact Center, Key Accounts, and Multifamily Partnership Program. Together these units employ 95 full time workers and 75 contract employees and handle more than 1.5 million customer contacts a year.

The Residential Contact Center initially handles all questions and issues related to residential electric, water, wastewater, drainage, and solid waste utility accounts. The Commercial Contact Center performs a similar function for many of the commercial customers.

For those commercial customers whose needs go beyond the services provided by the Commercial Contact Center, Austin Energy's Key Accounts group provides a single point of contact for these largest customers. Currently, there are about 150 customers that qualify for Key Accounts services. These customers spend $500,000 or more annually for their electricity and account for approximately one-third of Austin Energy's annual revenue. The Key Accounts organization consists of the Internal Key Accounts team and the External Key Accounts team; the internal team is managed under the Customer Care umbrella and the External team is managed under Customer Energy Solutions. Internal Key Accounts staff work closely with their customers, providing personal updates during outages, account and technical services coordination, and email updates on important utility-related activity, including key City Council actions. External Key Accounts staff focus on encouraging the large commercial customers to participate in AE's suite of energy conservation programs and provide on-site consultation regarding the customer's energy services. Additionally, two Key Accounts representatives are dedicated to serving AE's remaining commercial and residential customers. Key Account customers are assigned a Key Account Manager (KAM) who is the single point of contact for the customer and handle all customer requests related to Austin Energy's services.

Key Accounts manages all aspects of customer relationships with Key Accounts customers, coordinates all commercial customer communications, makes it easier to do business with Austin Energy by managing internal touch points, promotes and sells products, and serves as a vehicle for economic development in the service territory. KAMs coordinate technical electric service requests such as primary service, dual feed, and infrastructure construction bonds. Additionally, they sell energy conservation and demand response along with GreenChoice and Load Profiler, an online product that allows customers to monitor their usage. Power sensitive customers have access to a password protected website to see performance data on their power quality meter that gives them the magnitude and duration of a voltage sag situation affecting their operations. Should a voltage sag of 15 percent or greater occur, KAMs provide individualized updates. At quarterly Key Accounts meetings with sensitive power users, KAMs also report on any condition outside the AE system, providing the root cause analysis.

Finally under the UCC umbrella, the Multifamily Partnership Program supports apartment complex managers in Austin Energy's service area. This program provides a single point of contact for the complexes and provides their managers with educational workshops about Austin Energy's processes and procedures and offers enhanced web and e-business tools to allow the multifamily clients to better monitor and proactively address any issues that might arise.

3.6.5.2. Customer Service Management

Created in 2004, the Customer Service Management (CSM) division addresses customer concerns and issues that are too complex to be handled by the front line UCC employee. The division supports customers whose accounts require more specialized handling, like medically vulnerable individuals. CSM's knowledgeable workforce seeks to provide effective, efficient, and innovative solutions that address customer concerns while exceeding the public's expectations. Some tasks performed by the CSM group include responding to high billing or consumption complaints and resolving escalations requiring in-depth account reviews and monitoring. There is also one CSM employee at each AE walk-in center to handle any escalations that might arise. This group of 23 employees handles approximately 20,000 escalations a year.

CSM directly supports the customers participating in the City's Consumer Assistance Programs (CAP). These programs are designed to assist customers facing financial difficulties as well as serious medical problems. One component of this program is the CAP discounts. The CAP discounts reduce the bills of eligible customers by lowering charges for total electrical usage, providing a discount on the Community Benefit Charge, and waiving the electric service customer charge. These discounts are available to customers who participate, or live with a participant, in one of the following programs designed to support vulnerable populations in Texas: Medicaid; Supplemental Nutrition Assistance Program; Children's Health Insurance Program; Telephone Lifeline Program; Travis County Comprehensive Energy Assistance Program; Medical Access Program; Supplemental Security Income; and Veterans Affairs Supporting Housing.

Another Customer Assistance Program is the Plus 1 program. For this program, AE partners with a variety of Austin area social service agencies to provide one-time monetary assistance to customers who are experiencing a financial crisis impacting their ability to pay their utility bills. Plus 1 is funded in part through voluntary contributions made by other Austin Energy customers wishing to support their local community.

The CSM provides additional support to customers with a long-term or critical illness or ailment. Once a customer qualifies for the registry for the medically vulnerable, the customer receives additional time to pay the utility bill and personal case management from Austin Energy and partnering social services agencies.

Finally, the CSM work group works with EES to administer Austin Energy's Free Home Energy Improvements program. This endeavor targets low-income customers and helps them save energy while improving their comfort by installing efficiency measures like, attic insulation, minor duct repair and sealing, caulking, weather stripping on doors, and solar screens at no cost to the customer.

3.6.5.3. Austin 3·1·1

Austin Energy operates the City's information call center, known colloquially as Austin 3·1·1. It serves an essential function for Austin Energy's customers as a roll-over and back up call center. If Austin Energy's primary call center should experience a systems failure — caused by computer difficulties, electrical outages, facility problems, or natural or other types of disaster — Austin Energy can roll over call center services to the Austin 3·1·1 center and continue providing a critical line of communication to its customers. Without Austin 3·1·1, Austin Energy would have to contract with an independent vendor to provide these same services.

3.6.5.4. Billing Services

The Billing Services work group enables Austin Energy to receive payment for the electric service it provides to its customers. This function is one of the most fundamentally important services the utility provides its customers: if bills are not calculated accurately, generated and distributed on time, and collected fully, the utility cannot continue to serve its customers efficiently. Specifically, the Billing Services group is responsible for bill calculation, preparation, and presentment; generating bill data and sending it to the third party vendor who prints the bills; posting adjustments; sending advanced meter readings to customers; reviewing and releasing credit balances; posting and processing utility payments; and performing some collections activity, including managing the contract with the collections agency and collecting on non-sufficient funds accounts.

In addition to processing the bills for electric service, Austin Energy uses its billing system, Customer Care & Billing (CC&B), to bill for all the utility services provided by the City including water, wastewater, garbage collection, and other solid waste services. By centralizing the billing functions for all City utilities within Austin Energy, the City achieves greater cost efficiency, and the customers receive one monthly bill instead of individual bills for each service. While Austin Energy bills for all City services, the costs of this service are shared among all the City-owned utilities.

The CC&B system creates more than 5 million bills annually, recovering revenue of more than $1.9 billion. CC&B is a flexible and robust Oracle billing product, used by utilities across the world. The system tracks meter configurations, historic premise and usage data, customer information, and account management notes.

3.6.5.5. Revenue Measurement & Control

The Revenue Measurement & Control group is responsible for meter reading, completing field service orders, and identifying and investigating tampering cases. The team also identifies faulty meter equipment. These functions protect the utility's revenue stream by ensuring that consumption is accurately recorded and can then be accurately billed.

While most AE customers now receive their electric service through a smart meter, AE still employs some meter readers. These workers place door hangers prior to disconnect and perform manual re-reads of an electric meter when billing disputes arise.

3.6.5.6. Quality Management

The work in the Customer Care division is highly process driven. Without a behind-the-scenes team ensuring that those processes have been thoroughly mapped and vetted, Customer Care employees cannot provide the services that Austin Energy's customers require. It is the job of the Quality Management group to be that behind-the-scenes team. This group is responsible for developing and monitoring the processes and procedures that enable all the other Customer Care teams to complete their tasks successfully. QM employees work with Customer Care process managers to improve quality, increase productivity, and raise customer satisfaction. When those processes fail to work as anticipated, the members of the QM work group investigate the root causes of that failure and strive to correct the problem. The QM team also conducts many of division's trainings to help employees learn how to provide the best possible customer service.

3.6.6. Customer Success Conclusions

Austin Energy's customer-facing business operations provide economic and societal benefits that reflect the community's values. Through customer-empowering programs that help lower bills and reduce emissions, AE's operations are designed to offer meaningful and affordable services. Additionally, Austin Energy's efficient customer service programs help make it easy for its customers to work with the utility, resolve any problems they may encounter, and rely on Austin Energy to deliver reliable and essential electric service.

4. REVENUE REQUIREMENT

The first step in the rate review process is determining the utility's total revenue requirement. For a municipally owned utility like Austin Energy, particular elements of this determination will be required. In general, however, the revenue requirement represents the utility's adjusted expenses and investments required to provide reliable electric service to customers and fulfill the utility's strategic objectives. To ensure that rates adequately recover costs, the utility examines historical expenditures, capital improvement requirements, and customer loads, all of which are then adjusted for known and measurable changes that occur under normalized conditions. Austin Energy's rates must also reflect certain community and policy priorities, as determined by the City Council, as well as accounting and financial standards and methods that apply to MOUs. This chapter describes in detail how Austin Energy calculated its revenue requirement.

4.1. TEST YEAR CONCEPT

Pursuant to state law and long-standing regulatory policies, the starting point for setting a municipally owned utility's rates are the annual actual costs that have been incurred each year to deliver service to its customers and fulfilling its obligations to the community. Because a natural lag between the conduct of a cost of service study and the availability of historic cost accounting information exists, it is common industry practice to adjust historical test year information based on current concrete knowledge available at the time of the study. These adjustments typically reflect changes in system costs, revenues, or customer composition that are "known and measureable."[51] Examples of known and measurable cost adjustments include new costs reflective of current operations, adjustments of historical costs that have changed significantly, and removal of costs no longer relevant or useful to customers.[52] Municipally Owned Utilities (MOUs) commonly rely on approved budgets to make certain known and measureable adjustments, like salary increases. These adjustments are made to historical cost accounting records in order to establish rates based on costs that reflect current operating conditions.

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[51] To make such an adjustment, the utility must show that 1) the adjustment is quantifiable and 2) the adjustment reflects an investment or expense that either is used and useful in the delivery of electric service or will become so prior to the effective date of the supporting rate structure.

[52] Examples include one-time events, abnormal weather or operating conditions, changes to costs since completion of the fiscal year, or other events not reflected, or improperly reflected, in the historical year.

In addition to making known and measurable adjustments, the utility will normalize certain costs to reflect more typical operating conditions or adjust costs that were incurred for part of the historical year to reflect a full twelve months of operations.

All of these known and measurable adjustments are then applied to the historical audited financial statements, resulting in a Test Year revenue requirement.

For this rate review process, Austin Energy used FY 2014 — October 1, 2013 through September 30, 2014 — financial records, as these represent the most recent audited financial records[53] available when the study began. These records were then normalized to reflect typical conditions and certain expenses were annualized in order to reflect a full twelve months of operating costs. The audited financial statement results for FY 2014, as well as the adjusted TY 2014 results, are provided in Figure 4.3.

These adjustments resulted in an approximately $1.217 billion TY 2014 revenue requirement for the retail electric utility. This revenue requirement does not include the costs of non-electric services, such as the district cooling and heating business, or regulated transmission costs.[54]

4.2. CASH FLOW METHODOLOGY

Austin Energy uses the cash flow methodology to establish its total revenue requirement. Under this approach, the total revenue requirement represents the gross annual cash Austin Energy needs to operate, maintain, and capitalize the utility, including the cost of operations and maintenance, transfers and shared services, cash funded capital, replenishment of reserve funds, annual debt service payments on electric bonds, and satisfying debt covenants.

MOUs generally use the cash flow methodology, an accepted cost accounting method within the electric utility industry.[55] Using the cash flow approach accurately reflects the realities of MOUs, which,

[53] A benefit of using audited financial records is they reflect the independent review and scrutiny of an outside accounting firm.

[54] Non-electric services have revenue streams that recover operations and maintenance costs separate from base electric rates. These revenues are collected directly from customers who benefit from the specific service. Transmission costs are recovered through a separate transmission cost of service filing that is made at the Public Utility Commission of Texas.

[55] During AE's most recent complete Transmission Cost of Service filing, the PUCT's final order noted: "The cash flow method is typically used by public utilities because public utilities rely on revenue bond financing for more favorable interest rates as opposed to asset-based financing." *See*, *Application of City of Austin d/b/a Austin Energy to Change Rates for Wholesale Transmission Service*, Docket No. 31462, Finding of Fact No. 24 (June 9, 2006). Notwithstanding this Finding, PUCT staff did question the use of the cash flow method in Docket No. 40627. The cash flow method is the basis for AE's current retail electric rates.

as non-profit entities, are primarily concerned with meeting their budget, contributing to their City's general fund, and meeting their financial obligations, including debt service requirements.

Consistent with AE's financial policies, the current revenue requirement calculation includes the following: 1) reasonable operating and maintenance expenses; 2) debt service; 3) cash margins to fund capital projects; 4) annual deposits to replenish required reserves; 5) general fund contribution to the City; 6) recognition of other revenues to be earned, such as new service connections; and 7) all other miscellaneous financial obligations related to providing electric service.

Austin Energy follows the Federal Energy Regulatory Commission Uniform System of Accounts guidelines for determining the utility's revenues, expenses, assets, and liabilities. While FERC accounting is required for all Investor-Owned Utilities (IOUs), it is not a regulatory requirement for most MOUs. However, adhering to FERC accounting guidelines represents an industry best practice that AE has chosen to follow. The revenue requirement calculation, including work papers for all adjustments, and the cost of service analysis results identifies all utility expenditures by FERC account as provided in the Appendices.

Key components of the revenue requirement calculation are described below.

4.2.1. <u>Operation and Maintenance Expenses</u>

Operation and maintenance (O&M) expenses reflect all the costs required to operate and maintain the utility; provide efficient and reliable electric service to customers, including providing excellent customer service; and all maintenance and repair of utility assets. Austin Energy incurs O&M expenses for each of its four primary utility functions: Production, Transmission, Distribution, and Customer Service. For Austin Energy, O&M expenses make up 82.5 percent of the utility's total test year revenue requirement. FERC accounting methodology categorizes O&M expenses into the following categories:

- Power Production[56] — includes fuel, labor, routine maintenance, system control and dispatch of power plants, and purchased power expenses
- Transmission[57] — includes labor and routine maintenance for transmission lines and transmission substations

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[56] Power Production refers to the generation of electricity.

[57] Transmission reflects the infrastructure by which electricity produced at power plants is transported over long distances to customers. The transmission function is defined as facilities operating at a voltage of 69,000 volts (69 kilovolts or kV) or higher.

- Distribution[58] — includes labor and routine maintenance for overhead and underground distribution lines and circuitry, distribution substations, streetlights, service transformers, and meters

- Customer — includes meter reading, billing, collections, sales, advertising, customer assistance, and other customer service and communication activities

- Administrative and General (A&G) — includes salaries of general and administrative personnel, office supplies and expenses, insurance, outside services, injuries and damages, employee pensions and benefits, and other general expenses. Because AE is a department of the City of Austin, certain administration and general support functions are provided by the City and therefore, AE reimburses the City for these services.

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

Austin Energy's financial policies require the inclusion of the annual depreciation expenses for its plant and facilities, as well as amortization of Contributions in Aid of Construction (CIAC), in the revenue requirement calculation.

Depreciation expenses reflect the use of an asset or group of assets over their estimated life. For example, an asset with an estimated life of 30 years may have one-thirtieth (1/30 or 3.33 percent) of its original cost as an annual depreciation expense to reflect the age and value of the asset. Depreciation expense does not represent an actual cash expense, as AE incurs the asset's cash expenditure at the time of its construction or installation. Under the cash flow methodology, depreciation expense is a source of cash whereby the cash associated with this line item in the revenue requirement can be used to pay for AE's other cash obligations, such as capital improvement projects, debt service, general fund transfers, or the funding of reserves. As a result, the cash generated from depreciation expense reduces other cash obligations of the utility, effectively netting this component to zero and removing it from the total revenue requirement determination.

CIAC reflects the contributed capital AE receives from customers associated with the cost of extending or connecting utility service to customers, and AE amortizes these capital contributions over the life of the underlying asset. Similar to depreciation expense, amortization of CIAC is a non-cash item in the revenue requirement which generates cash to be used for other cash obligations of the utility.

[58] Distribution is the final stage in the delivery of electricity to customers and includes stepping down the service voltage to a level of usage that is safe for different customer types. On AE's system, distribution equipment is generally operated at less than 69 kV and includes the electrical equipment that directly serves customers.

4.2.3. Capital Expenditures

Electric utilities are extremely capital intensive due to the large investment needed to develop and maintain the electric utility system. Utilities must continually add new infrastructure and upgrade or replace existing infrastructure to ensure high system reliability. For example, Austin Energy spends approximately $95 million each year on capital expenses for its distribution system and spends another $62 million each year on capital expenses for its production operations.[59] Austin Energy funds these capital projects through its capital improvement program with a combination of debt, reserves, and current cash margins generated from rates. Annually, AE finances about 50 percent of its capital expenditures from debt and the other half from cash margins. This treatment is consistent with the requirements of AE's financial policies.

4.2.3.1. Debt Service

Austin Energy uses a combination of short- and long-term financing instruments to fund the debt portion of its five-year, $400 million Capital Improvement Program (CIP). Under City Council's current financial policies, AE will pay for about 50% of CIP expenses in cash and will borrow the other 50% through its debt financing program.

For short-term financing, AE uses a commercial paper program through which the utility can borrow funds as needed to pay for capital projects. The commercial paper program operates like a letter of credit a homeowner may have with a bank. Typically, Austin Energy will borrow funds in smaller increments at extremely low interest rates over about a 12 to 18 month period. Once AE accumulates approximately $200 million of short-term debt, AE converts the commercial paper into long-term debt.

Long-term financing is similar to a homeowner's mortgage and requires AE to pay principal and interest on the debt over the term of the issue. AE's long-term is typically issued as electric utility revenue bonds, the repayment of which is guaranteed by AE's annual revenues. Per financial policy, the term of AE's long-term debt generally does not exceed 30 years because AE cannot finance capital projects beyond their useful life. Austin Energy's revenue requirement calculation includes both annual debt service expenses, like principal and interest payments, associated with long-term debt and the interest expenses related to short-term commercial paper borrowing.

[59] AE receives about $18.5 million in Contributions in Aid of Construction, payments made by AE customers towards capital improvement projects that directly benefit the specific customer. *See* Appendix G, Schedule C-3 and associated work papers.

Per financial policy,[60] AE must maintain a debt service coverage ratio[61] of not less than 2.0x on electric utility revenue bonds. Traditionally, utilities with lower debt ratios and higher debt service coverage ratios have received higher credit ratings. Higher credit ratings resulting in lower borrowing costs for the utility, a savings that can be passed on to customers through lower annual debt service payments. In addition, a 2.0x coverage ratio aligns with debt service coverage ratios of other public power utilities across the country. According to American Public Power Association (APPA) 2013 data, municipal electric utilities that serve more than 100,000 customers have a median debt service coverage ratio of 2.25.[62] Assuming rate revenues are adjusted as proposed by AE, Figure 4.1 shows that meeting the proposed TY 2014 revenue requirement achieves a debt service coverage ratio of 2.32; while TY 2014 revenues at current rate levels yield a debt service coverage ratio of 2.16. Therefore, providing adequate funding of AE's revenue requirement through rates ensures that this financial policy is met.

Figure 4.1
Debt Service Coverage

Item	FY 2014[(1)]	Adjustments	TY 2014[(2)]
Debt Service Coverage Ratio	2.16	0.16	2.32

Note:

1) FY 2014 includes non-electric business
2) TY 2014 is based on proposed rates

It should be noted under the cash flow method the debt service coverage ratio does not have an impact on the revenue requirement.

4.2.3.2. <u>Internally Generated Funds for Construction</u>[63]

AE pays the remaining costs associated with the capital improvement program with current cash margins generated by rate revenues. Austin Energy currently maintains this cash in its Capital Improvement Program Fund and its Repair and Replacement Fund.[64] In AE's revenue requirement

[60] *See*, Financial Policy No. 6 in Appendix N.

[61] Debt service coverage ratio is the ratio of cash available for servicing interest, principal, and lease payments to the total annual debt payments the utility is required to make.

[62] APPA Selected Financial and Operating Ratios of Public Power Systems, 2013 Data (February 2015).

[63] In some attached reports, this line item may be referred to as "Capital Paid."

[64] As discussed in Section 4.4.1, the Repair and Replacement Fund is proposed to be renamed the Capital Reserve.

calculation, capital improvement projects funded with current cash are included in the cash margin calculation described below.

4.2.4. General Fund Transfer

It is legally permissible for MOUs including AE to transfer a certain percentage of revenues to their municipal governing body. MOUs provide general fund transfers instead of paying franchise fees, taxes, dividends, return on investment and similar expenses borne by IOUs. As with IOUs, these costs are recovered from all utility customers. Unlike IOUs, these funds are then invested directly back into the local community rather than flowing to outside investors, a unique benefit of public power.

By City policy, Austin Energy pays an annual General Fund Transfer to the COA in an amount not less than $105 million but not to exceed 12 percent of AE's three-year average revenues minus power supply costs and district cooling and heating business unit revenues.[65] The General Fund Transfer included in the test year revenue requirement is $105 million, the lowest amount permitted under City Council policy.

4.2.5. Cash Margins

The cash margin reflects Austin Energy's remaining cash needs after all other components of the revenue requirement have been addressed. The cash margin calculation considers sources and uses of cash. Cash sources include depreciation expense net of amortized CIAC, as well as interest and dividend income and CIAC.[66] Cash uses include capital expenditures from current cash margins and required contributions to reserves.

As shown in Figure 4.2, the TY 2014 required cash margin is $143,935,003.

[65] The General Fund Transfer is calculated using the current year estimate and the previous two years' actual revenues and power supply costs from the City's Comprehensive Annual Financial Report.

[66] Due to a change in the line extension policy, CIAC increased since the previous rate review.

Figure 4.2
Cash Margin Calculation

Item	FY 2014	Adjustments	TY 2014
Cash Sources			
Depreciation & Amortization ($)	147,302,442	(6,798,240)	140,504,202
CIAC ($)	13,036,715	5,476,505	18,513,221
Interest and Dividend Income ($)	5,191,382	(558,230)	4,633,152
Cash Sources Total ($)	**165,530,540**	**(1,879,965)**	**163,650,575**
Cash Uses			
Debt Service ($)	130,995,451	(28,342,030)	102,653,421
Required Reserve Contributions ($)	-	11,590,703	11,590,703
General Fund Transfer ($)	105,000,000	-	105,000,000
Internally Generated Funds for Construction ($)	88,866,639	(525,185)	88,341,455
Cash Uses Total ($)	**324,862,090**	**(17,276,512)**	**307,585,578**
Required Cash Margin ($)	**159,331,551**	**(15,396,547)**	**143,935,003**

4.2.6. Other Expenses

The Other Expenses represent a relatively small amount of the revenue requirement. This is in part because the most significant Other Expense item, AE's district cooling and heating business unit, is a non-utility operating expense that AE has removed from the revenue requirement. All direct and indirect non-utility operations expenses, including the underlying investment, have been removed from the revenue requirement.

4.2.7. Revenue Requirement Offsets

As described above, the revenue requirement calculation captures the total annual revenue needed by the utility for it to operate and serve customers. Included within this total are expenses that are not appropriately recovered through base rates. Instead, AE collects these costs through a compendium of miscellaneous service charges and monthly pass-through amounts. As the over-arching objective of calculating the revenue requirement is to determine the total costs that must be recovered through base rates alone, revenue collected via these additional methods must be computed as an offset to the revenue requirement, allowing the utility to determine the final amount to recover through base rates.

4.2.7.1. Other Revenue

Non-rate revenue related sources of income must be subtracted from the total system revenue requirement to prevent an over-recovery of revenue. Other revenue sources include connection charges, equipment rentals, service charges, maintenance agreements, among other charges. These income adjustments lower the overall revenue requirement.

4.2.7.2. Pass-Through Items

Pass-through items are rate components that, in compliance with tariffs previously approved by the City Council, can be adjusted during the annual budget process. This annual adjustment process is necessary because these actual costs can vary greatly from year to year. For example, one of the pass-through items is the Power Supply Adjustment charge that is typically billed to customers based on total monthly amount of electricity consumed. A pass-through charge is the best option for a PSA due to the volatility of fuel and power prices and the uncontrollable nature of their markets. Other pass-through charges include the Regulatory Charge to recover regulated transmission costs and ERCOT and Texas RE fees and the Community Benefit Charge to recover costs associated with funding community service area street lighting,[67] AE's Customer Assistance Program, and AE's energy efficiency service programs. These pass-through charges are addressed in Chapter 6.

Once AE's overall revenue requirement is adjusted for other revenue and pass-through items, the remaining balance must be recovered through base rates.

4.3. TEST YEAR ADJUSTMENTS

Austin Energy has made several adjustments to the audited FY 2014 data to reflect known and measurable changes, normalized operations, and annualized financial and operating conditions. These adjustments take into consideration costs and revenues that are influenced by one-time events, abnormal weather or operating conditions, changes to costs since completion of the fiscal year, or other events not reflected or improperly reflected in the FY 2014 financial data. Adjustments related to changes in cost structure, customers, or other factors are limited to items that are known, measurable, and in service by the time rates become effective. Figure 4.3 lists the adjustments made to FY 2014 financial results by major categories for both revenue and expense items and result in a $57,740,929 total decrease to the revenue requirement. Revenue and expense adjustments are shown in Figure 4.3,

[67] The charge for Service Area Lighting is assessed only to customers inside the City limits and is designed to cover the cost associated with providing street light service within the City of Austin.

where positive items raise the revenue requirement and negative items (those in brackets) lower the revenue requirement. Items that are $0 have no effect on the revenue requirement. These items transfer dollars between FERC accounts. Appendix G provides a summary of the adjustments by FERC account and a description.[68] Supporting documentation for these adjustments is included in the cost of service model in the form of work papers. These work papers are contained in Appendix G and include the calculations and assumptions used to determine the adjustments, as well as references to source documents.

[68] *See*, Schedule D and associated work papers in Appendix G: Rate Filing Package.

Figure 4.3

Test Year 2014 Adjustments by Major Revenue Requirement Category

		Revenue Requirement Category						
	Adjustment	**Total Operations & Maintenance Expenses**	**Depreciation & Amortization**	**Debt Service**	**Margin**	**Other Expenses**	**Other (Non-Rate) Revenue**	**Total Adjustment**
1	South Texas Project	(4,365,205)	-	-	-	-	-	(4,365,205)
2	Sand Hill Energy Center	(3,536,521)	-	-	-	-	-	(3,536,521)
3	Reclassify Recoverable Gas Expense	0	-	-	-	-	-	0
4	Adjust Recoverable Power Supply Costs to Normalized Year	(64,336,057)	-	-	-	-	-	(64,336,057)
5	Non-Nuclear Decommissioning Costs	19,442,308	-	-	-	-	-	19,442,308
6	Holly Power Plant	(363,144)	-	-	-	-	-	(363,144)
7	Reclassify Energy Efficiency Costs to Production	0	-	-	-	-	-	0
8	City Services	(1,824,355)	-	-	-	779,252	-	(1,045,103)
9	Test Year Labor	1,409,396	-	-	-	-	-	1,409,396
10	Uncollectible Accounts	(4,813,622)	-	-	-	-	-	(4,813,622)
11	Miscellaneous Non-operating Income	20,922,827	-	-	-	(17,389,381)	-	3,533,446
12	Rate Case Expense	538,333	-	-	-	-	-	538,333
13	Transmission by Others	8,832,134	-	-	-	-	-	8,832,134
14	Remove Grant Consolidation Entry	(1,014,013)	-	-	-	-	-	(1,014,013)
15	Benefits from CAP Revenue	(1,974,646)	-	-	-	-	-	(1,974,646)
16	Separate Non-Recoverable FERC 555 (GreenChoice)	0	-	-	-	-	-	0
17	Separate Non-Recoverable FERC 556 (ERCOT Admin)	0	-	-	-	-	-	0
18	CRR Credits - Regulatory Revenue	-	-	-	-	-	1,258,619	1,258,619
19	Transmission Service Revenue	-	-	-	-	-	6,844,343	6,844,343
20	Debt Service			(24,499,117)				(24,499,117)
21	Reserve Fund Contribution	-	-	-	11,590,703	-	-	11,590,703
22	Normalized Capital Improvement Program	-	-	-	2,238,482	-	-	2,238,482
23	Contribution in Aid of Construction				(5,693,910)			(5,693,910)
24	Interest & Dividend Income	-	-	-	558,230	-	-	558,230
25	Non-Electric Revenue	-	-	-	-	-	18,471,610	18,471,610
26	Non-Electric Expenses	(592,816)	(6,798,240)	(3,842,913)	4,251,978	(13,835,205)	-	(20,817,197)
	Category Total	(31,675,379)	(6,798,240)	(28,342,030)	12,945,483	(30,445,334)	26,574,571	(57,740,929)

Significant revenue requirement adjustments have been made to:

- *Power Supply Costs*:[69] Reducing the total revenue requirement by $64 million, the change in power supply costs represents a recalibration of the Power Supply Adjustment due to the over-collection of revenues in FY 2014. The primary factor adjusting total power supply costs down to $437.2 million reflects decreasing costs of natural gas, a primary fuel used in the generation of electricity. Ultimately, power supply costs are removed from the base revenue requirement and collected through the Power Supply Adjustment charged separately from base rates.

- *Non-Nuclear Decommissioning*:[70] Financial policies require AE to set aside funds to pay for the eventual retirement and decommissioning of the utility's non-nuclear fuel generation fleet. AE's non-nuclear fleet consists of Decker Creek Power Station, Fayette Power Project, and Sand Hill Energy Center. Funds must start accumulating no later than four years prior to commencement of decommissioning activities. Annual expenses are increased to add $19.4 million of revenue to cover decommissioning expenses. Of the total adjustment, $14 million is earmarked for the retirement of Decker Creek in the near-term, $3.75 million is set aside for the retirement of AE's portion of Fayette in the mid-term, and $1.7 million is directed toward the eventual retirement of Sand Hill in the long-term.

- *Bad Debt*:[71] Uncollectibles have been reduced by $4.8 million due to continuing improvements on collections on past due accounts.

- *Transmission Cost of Service*:[72] Total payments to the Transmission Service Providers in the ERCOT region have increased since FY 2014. PUCT Docket No. 43881 establishes the rate that AE must pay other TSPs for its use of the transmission system and the rate other DSPs must pay AE for their use of AE's portion of the transmission system. The $8.8 million increases AE's total net TCOS payments to just above $116.9 million. Ultimately, TCOS payments are removed from the base revenue requirement and collected through the Regulatory Charge assessed separately from base rates.

- *Reserve Funds*:[73] To continue building reserves to the levels established by City financial policies, an $11.6 million addition to the revenue requirement has been made. AE calculated target funding levels for each of the existing reserve funds and compared them with current cash balances as of FY 2015. The difference is proposed to be collected over three years; therefore, the total shortfall was divided by three and the quotient was added to the total revenue requirement. See Section 4.4 for additional discussion on reserve funds.

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[69] *See*, Appendix G, Work Paper D-1.2.4.

[70] *See*, Appendix G, Work Paper D-1.2.5.

[71] *See*, Appendix G, Work Paper D-1.2.9.

[72] *See*, Appendix G, Work Paper D-1.2.11.

[73] *See*, Appendix G, Work Paper C-3.2.

- *Debt Service*:[74] Total debt service payments have been reduced by approximately $24.5 million to reflect a combination of lower borrowing levels since FY 2014 and a refinancing effort which reduced total debt service payments on existing revenue bonds.

- *Contributions in Aid of Construction*:[75] Austin Energy capital projects that provide a direct benefit to individual customers are recovered in part or in total by the benefited customers. An example of this is the service charge that AE levies for distribution line extensions and service drops for some types of new customers. Per City Council policy, Austin Energy continues to improve its overall effort to recover these costs, and thus TY 2014 revenue requirement is reduced by $5.7 million.

- *Non-Electric Revenues and Expenses*:[76] This adjustment removes all revenues and expenses associated with Austin Energy's district cooling system, a service that provides large commercial buildings with chilled water for heating and cooling purposes. The service serves customers with a peak shifting service that lowers energy consumption during the highest priced hours of the year. As this service is not directly related to providing electric service, all revenues and expenses have been removed from the test year revenue requirement.

4.4. CITY OF AUSTIN FINANCIAL POLICIES

The TY 2014 revenue requirement is consistent and complies with AE's financial policies, business goals, and objectives. Meeting the utility's revenue requirement is critical to ensuring the long-term financial viability of the utility, one of the main objectives of this rate review, as discussed in Chapter 2.

The City has adopted financial policies that include requirements related to capital structure, funding sources, debt and debt service coverage, general fund transfer, and reserves. Austin Energy's financial policies[77] are reviewed annually for compliance, and any changes to the policies must be approved by City Council during the annual budget process. These policies include financial targets intended to help the utility achieve sound credit ratings[78] and meet industry benchmarks of financial health. In addition, these financial policies include bondholder protections and targets for debt service, liquidity, and reserves. Abridged AE financial policies are included in Appendix D. Austin Energy has a

[74] *See*, Appendix G, Work Paper C-3.1.

[75] *See*, Appendix G, Work Paper C-3.6.

[76] *See*, Appendix G, Schedule A, Schedule E-1, Schedule E-4, and Work Paper E-5.1.

[77] The financial policies were initially adopted by the City Council in 1989 and are included as Appendix N.

[78] A credit rating evaluates the credit worthiness of an issuer of debt such as a business enterprise or a governmental body. A higher rating implies a less risky investment and will typically result in lower interest costs to the issuer.

fiduciary responsibility to its bondholders and customers to set rates that comply with the financial targets set forth in these policies.

Since the last full Cost of Service study, Moody's Investors Services adopted a new ratings methodology for public power generation owners. This new methodology focuses on five key rating drivers: 1) the cost recovery framework within a utility's service territory; 2) the utility's willingness and ability to recover costs with sound financial metrics; 3) generation and power procurement risk exposure; 4) competitiveness; and 5) financial strength and liquidity.[79] By addressing these components, Austin Energy consistently enjoys high quality bond ratings[80] due to its debt to equity ratio, rates and rate policies, and increasing liquidity.[81] Having this strong credit rating keeps interest rates on debt issued by the utility low, saving the utility and its ratepayers money in the long run.

Among other strategies designed to help Austin Energy meet its financial targets, AE sets aside funds for future use, especially on activities that may create uncertainty or present a financial risk to AE's overall operations.

4.4.1. Existing Reserve Policies

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

City financial policies require Austin Energy to establish the following five reserve funds:

- Working Capital is the cash available to fund day-to-day operations. Target funding level is cash equivalent to 45 days of non-power supply operating requirements.
- The Strategic Reserve consists of three sub-funds that can be used in the event of unanticipated events that could significantly impair the utility's financial stability and overall liquidity. The Strategic Reserve provides last resort funding for natural disasters, unplanned plant outages, and other unexpected costs.
  - Emergency – May only be used as a last resort to provides for extraordinary events that present financial risk. Can only be used once the Contingency has

[79] Moody's Investors Service, Rating Methodology: U.S. Public Power Electric Utilities with Generation Ownership Exposure, December 29, 2015. Included as Appendix D.

[80] For FY 2015, AE held an AA- stable bond rating with Fitch Ratings, Inc.; an A1 stable bond rating with Moody's Investors Service, Inc.; and an AA- stable bond rating with Standard and Poor's.

[81] Liquidity is a measure of the ability of a debtor to pay its debts.

been exhausted. Minimum funding level is 60 days of non-power supply operating requirements

- Contingency – May be used for unexpected events that reduce revenue or increase expenses. Maximum funding level is 60 days of non-power supply operating requirements.
- Rate Stabilization – Goal is to have funds that can stabilize rates in the future by deferring or minimizing future rate increases, including for the PSA. Accumulated funds exceeding the 120 days of non-power supply operating requirements identified for the Emergency and Contingency reserves may be placed in the Rate Stabilization reserve.

- The Repair & Replacement Fund can be used to extend, add, replace and improve AE's production and distribution systems. Target funding level is 50 percent of the previous year's depreciation expenses.
- Non-Nuclear Decommissioning reserves are set aside to offset the expenses associated with the eventual retirement and decommissioning of AE's non-nuclear fueled generation resources. Funding levels are set based on decommissioning studies and must be set aside over a minimum of four years prior to expected plant closure.
- The Capital Improvement Plan (CIP) Fund accrues funds for the equity portion of planned capital projects. The CIP Fund pays for current and ongoing capital projects, and therefore, it does not serve as a reserve fund per se, rather acting as a funding mechanism for approved capital projects.

Reserve fund analysis exclude restricted reserves that are required by external policies or regulations, namely the Bond Reserve, the Debt Service Reserve, and the Nuclear Decommissioning Trust. The Bond Reserve was funded in FY 2010 with $44 million to comply with Financial Policy No. 4. The Debt Service Reserve accrues monthly deposits to facilitate periodic principal and interest payments on debt. The Nuclear Decommissioning Trust holds fund for the eventual decommissioning of AE's share of the South Texas Project. None of the three of these restricted reserves are included in the analysis of AE's cash adequacy since these funds cannot be drawn on for purposes other than those stated in policy or regulation.

4.4.1.1. Reserves in the Revenue Requirement

In order to calculate the amount of revenue required to meet City financial policies, Austin Energy compared the FY 2015 ending balances with the target funding level for each reserve. At the end of FY 2015, unaudited unrestricted reserves totaled $402,428,053. Existing financial policies require a total of $437,200,161, based on TY 2014 data. AE proposes to reach full reserve fund levels over three years. The recovery of the funding deficiency results in an $11.6 million known and measurable increase to the annual revenue requirement. Figure 4.4 details the revenue requirement calculations for AE's reserve funds.

Figure 4.4

Reserve Fund Revenue Requirement

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

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

Because AE is targeting specific cash balances rather than simply recovering costs experienced during the test year, use of unaudited FY 2015 year-end balances is the appropriate starting point for determining the required revenue. Additionally, Non-Nuclear Decommissioning and CIP Funds are excluded from the reserve fund calculations. Instead, they are included in the revenue requirement as expense items because they represents funds to be spent for specific purposes, as opposed to the reserve funds' general cash balances which can be used to mitigate unpredictable, risky events.

4.4.2. Proposed Restructuring of Reserve Policies and Funds

Based on direction from City Council, Austin Energy commissioned an independent study on the adequacy and use of its cash and reserves. In the 2012 rate ordinance, City Council directed AE to undertake such a study and a copy of the final result is included in Appendix I. Austin Energy retained NewGen Strategies & Solutions, LLC (NewGen) to review and examine AE's reserve funds, including an overview of supporting financial policies.[82]

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

Specifically, NewGen evaluated the intended purpose of each fund, compliance with reserve funding requirements per AE's financial policies, historical use of funds, and industry acceptance and appropriateness of reserve fund types and funding levels. Based on the results of these analyses, AE asked NewGen to explore structural and funding level changes that might help Austin Energy align its reserve funds more closely with industry best practice and City Council-approved financial policy.

Additionally, NewGen conducted an extensive engineering cost estimate to establish the estimated cost to decommission Decker Creek Power Station and developed a dollar per kW benchmarked cost estimate for decommissioning Fayette Power Project and Sand Hill Energy Center. The benchmarking analysis used historical examples of decommissioning costs based on unit type from utilities located around the country. These amounts were used to support funding level recommendations for the Non-Nuclear Decommissioning Reserve. The decommissioning cost estimates are included as part of the overall Reserve Fund Study.

Based on the conclusions of the study and on Austin Energy deliberations, AE recommends the following:

- Austin Energy's total unrestricted reserves, excluding the Non-Nuclear Decommission Reserve and CIP Fund, should meet or exceed 150 Days Cash on Hand, as measured by the rating agencies. Cash reserves at this level will help AE maintain its AA- credit rating and may help AE achieve a AA credit rating. This targeted level of liquidity is more consistent with, but still lower than, the reserves levels of other AA rated municipal utilities.

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

- Reserves should be modified and funded in the following manner:

  - <u>Working Capital Reserve</u> – As currently formulated, Austin Energy's calculation of the Working Capital Reserve funding is consistent with PUCT guidelines, which exclude fuel and other power supply costs from the calculation. However, Austin Energy recommends increasing the reserve to a minimum of 60 days non-power supply cash in order to incorporate Austin Energy's firm expense obligations associated with City transfers, including both shared services and the General Fund Transfer. Austin Energy recommends that there be a maximum limit on this reserve (*e.g.*, 90 days).

- Strategic Reserve – Austin Energy recommends eliminating this overarching reserve category in lieu of specific reserves, as described below:

  - Emergency Reserve – The use and application of the Emergency Reserve is duplicative with other reserve funds. Its distinct purpose lacks clarity with respect to other reserves and Austin Energy, therefore, recommends the elimination of this part of the Strategic Reserve.

  - Contingency Reserve – Austin Energy recommends that the Contingency Reserve balance be maintained at a maximum of 60 Days Cash On Hand, per AE's current policy. Contingency Reserve funds should be used to replenish all other reserves where funds drop below minimum levels. Contingency Reserve funds should be replenished as soon as practically possible and in the near-term, should be funded by a transfer from the eliminated Emergency Reserve.

- Rate Stabilization Reserve – Use and funding of the Rate Stabilization Reserve should be dedicated to the net Power Supply cost component of the rate structure. This treatment makes the reserve's funding criteria consistent with its calculation, which currently stipulates that the reserve level be funded at 90 days of Net Power Supply costs. In order to clarify that the purpose of these reserves is to smooth customer bill impacts caused by variation in power supply costs, Austin Energy recommends that this reserve be renamed the Power Supply Stabilization Reserve.

  - Austin Energy recommends that any funds remaining after closing the Emergency Reserve, after fully funding the Contingency Reserve, should be deposited into the Power Supply Stabilization Reserve. Further, Austin Energy recommends that the Power Supply Stabilization Reserve be funded going forward from net credit balances remaining in the Power Supply Adjustment over or under account balance upon the annual PSA revaluing, rather than included as a credit in the calculation of the subsequent PSA. This recommended funding process ties the funding source to the use of funds (*i.e.*, Net Power Supply under-recoveries are funded from prior Net Power Supply over-recoveries).

  - Austin Energy recommends that the Power Supply Stabilization Reserve maintain a cash balance between 90 and 120 days of Net Power Supply expenses.

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

  - Austin Energy recommends the Capital Reserve be funded at a minimum of 50 percent of the prior year's depreciation with no maximum amount identified. Without a maximum funding limit, Austin Energy recommends accruing additional cash reserves required to meet the total 150 Days Cash on Hand goal in this reserve. Capital Reserve funds are available for use on all AE approved capital projects and can be used to manage the debt to equity ratio of the utility in the long-term.

- Non-Nuclear Decommissioning Reserve – Austin Energy's financial policy requires that the expected cost of decommissioning a power plant be set aside over at least the four years prior to the commencement of plant decommissioning activities. Based on the Resource Plan Update to 2025, Austin Energy recommends an increase in funding for this reserve for the near-term needs of retiring Decker Creek Units 1 and 2, the medium-term need for Fayette Power Project retirement planning, and the long-term needs associated with closing Sand Hill Energy Center.

  - Austin Energy recommends targeting the high end of NewGen's estimated range of costs for Decker decommissioning, as mentioned in the separate "Non-Nuclear Decommissioning Cost Study" report, as a conservative approach to building Decker Creek decommissioning reserves. Any funding beyond the needs of decommissioning the Decker Creek units can be applied to the next facility to be decommissioned (Fayette Power Project).

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

Based on these recommendations, Austin Energy's proposed reserve funding criteria is summarized in Figure 4.5.

Figure 4.5
Recommended Reserve Funding Criteria

Name	Description	Minimum Funding Requirement	Maximum Funding Requirement
Working Capital	Reserve to meet the day-to-day normal expense obligations associated with O&M expense, less Net Power Supply	60 Days of O&M expense, less Net Power Supply	90 Days of O&M expense, less Net Power Supply (or other reasonable level as identified by AE)
Contingency	Reserve to meet emergencies or to replenish other reserves	60 Days of O&M expense, less Net Power Supply	60 Days of O&M expense, less Net Power Supply
Power Supply Stabilization	Reserve to mitigate unpredictable fluctuations in Net Power Supply costs in order to stabilize rates and meet affordability goals	90 Days of Net Power Supply expenses	120 Days of Net Power Supply expenses
Capital (formerly Repair and Replacement)	Reserve to meet the equity funding requirements for all capital projects	½ of prior year's annual depreciation	None (1)
Non-Nuclear Decommissioning	Reserve to provide sufficient resources to decommission non-nuclear generation plants	Initial funding at Decker decommissioning cost estimate	Initial funding at Decker decommissioning cost estimate

Notes:

1) The expectation is that total unrestricted reserves, excluding the Non-Nuclear Decommissioning Reserve and the CIP Fund, would be greater than or equal to 150 Days Cash on Hand, per rating agency measurement.

If the City Council were to adopt these recommendations on structural changes to AE's reserve policies and funding levels, AE expects a decrease in the annual revenue requirement of approximately $8.2 million. This decrease assumes a three-year amortization period as recommended under the current reserve policies.

Figure 4.6

Reserve Fund Revenue Requirement

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

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

(2) This fund would be renamed the Power Supply Stabilization Reserve.

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

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

4.5. TEST YEAR REVENUE REQUIREMENT

As detailed in Figure 4.7, the total TY 2014 revenue requirement is the sum of total O&M expenses, depreciation and amortization, and margin and other expenses less non-rate revenue. As previously described above and shown in greater detail in Figure 4.2, the test year margin requirement reflects an amount that takes into consideration the difference between the cash sources[83] and cash uses.[84] Given this calculation, the TY 2014 revenue requirement is approximately $1.217 billion. This revenue requirement reasonably reflects the utility's projected operating costs at the time proposed rates are expected to take effect in fall 2016.

[83] Sources of cash include depreciation and amortization, CIAC, and investment income.

[84] Uses of cash include cash capital improvements, General Fund Transfer, debt service, and required contributions to reserves.

Figure 4.7
Test Year 2014 Revenue Requirement

Item	FY 2014	Adjustments	TY 2014
Operation & Maintenance Expenses			
Production	$ 630,722,669	$ (18,295,231)	$ 612,427,438
Transmission	121,459,831	9,268,156	130,727,986
Distribution	56,823,106	3,384,207	60,207,313
Customer	86,827,033	(26,886,288)	59,940,745
A&G	139,890,673	853,777	140,744,450
Total Expenses	$ 1,035,723,311	$ (31,675,379)	$ 1,004,047,932
Depreciation & Amortization	$ 147,302,442	$ (6,798,240)	$ 140,504,202
Margin	159,331,551	(15,396,547)	143,935,003
Other Expenses	40,888,095	(30,445,334)	10,442,761
Other Non-Rate Revenue	(108,277,160)	26,574,571	(81,702,589)
Total Revenue Requirement	**$ 1,274,968,239**	**$ (57,740,929)**	**$ 1,217,227,310**
Test Year Rate Revenue	$ 1,246,153,540		$ 1,234,701,609
(Excess)/Deficiency	$ 28,814,698		$ (17,474,299)
(Excess)/Deficiency	2.3%		(1.4%)

Shown above, approximately $1.235 billion would be expected to be generated annually given AE's existing rates,[85] while the TY 2014 revenue requirement needed is approximately $1.217 billion. This results in current rates collecting revenues above costs by approximately $17.5 million, or 1.4 percent.

4.6. CONCLUSION

The result of the revenue requirement analysis indicates AE's current rates generate revenues above the costs of operation, maintenance, and other financial obligations. The overall system base rate revenue should be decreased by $17.5 million, or 1.4 percent. At this level, we anticipate that revenues will be sufficient to meet operation and maintenance expenses, debt service and debt service coverage, planned capital improvement expenditures, City transfers and franchise fee obligations, and required contributions to reserves.

[85] Using the same normalized customer sales used in the TY 2014 revenue requirement and Test Year fuel and other pass-through costs.

5. COST OF SERVICE STUDY

After determining the utility's total revenue requirement, the utility performs a Cost of Service study, which analyzes how to allocate the utility's costs to each customer class. This process attempts to distribute these costs as fairly as possible based on how much it costs the utility to serve each customer class. The following chapter describes the technical process of allocating the revenue requirement to the various customer classes and the results from Austin Energy's COS study.

5.1. BACKGROUND

The Cost of Service process distributes the utility's total revenue requirement by utilizing cost allocation methodologies commonly used throughout the utility industry, and in accordance with generally accepted practices. These methodologies and practices are described by the American Public Power Association, the National Association of Regulatory Utility Commissioners (NARUC), and the National Rural Electric Cooperative Association (NRECA).

For this current rate making process, Austin Energy completed an unbundled COS study, meaning that costs were first separated by their underlying business functions, and then allocated to customer classes in a fair and equitable manner. The fully allocated COS analysis shows how much a customer class should contribute to the revenue requirement and whether the class is over- or under-paying for electric service. This analysis enables AE to determine and adjust charges and to develop rates based on the way in which the utility incurs these costs and how they apply to each customer class.[86] The unbundled COS analytical process contains three broad distinct steps:

1. Cost Functionalization separates the historical test year expenses into major categories based on the utility's primary functions, which for Austin Energy are generation, transmission, distribution, and customer service.
2. Cost Classification further separates the functionalized costs into distinct categories based on the utility operations for which assets are constructed and operated. These categories are customer-related,[87] demand-related,[88] and energy-related.[89]

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[86] Unbundling rates creates opportunities for analysis and to explore new rate options for customer classes.

[87] Customer-related costs reflect the minimum amount of fixed costs (*i.e.,* equipment and service) the utility needs to supply for customers to access the utility system. These are the cost of meters, service drops, meter reading, meter maintenance, and billing. These are costs that vary with the addition or subtraction of customers. These costs do not vary with usage; therefore, these costs are properly considered customer-related costs rather than demand-related costs or energy-related costs.

3. Cost Allocation attributes the functionalized and classified costs to individual customer classes based on the service needs of each customer class. Costs unique to a specific customer class are directly assigned to that customer class. Costs incapable of direct assignment are allocated based on factors related to the type of cost and their contribution to total system costs, such as peak demand.

Customer classes exist because the cost to serve different types of customers varies. COS principles generally require customer class assignment to be based on the similarities and differences in load characteristics of groups of consumers. For instance, the cost to deliver electricity to a very large industrial customer is different than the cost to deliver electricity to a home. The industrial customer may receive power from a single large power line that extends directly from a substation, while homes receive their electricity through an extensive network of power lines which represents greater infrastructure costs to build and maintain. Therefore, the COS study seeks to allocate the cost to run the utility among the different customer classes as fairly as possible, based on the function and classification of the expenses incurred to serve different customer classes. By ensuring that each class contributes its fair share to the total revenue requirement, the cost of service process not only minimizes the amount of interclass subsidies but also more properly allows Austin Energy to account for cost shifting caused by energy conservation and demand side management programs.

The following sections describe each of the steps in the COS process, compare various methodologies for allocating fixed production costs, provide recommendations for allocating costs to customers, and summarize the results of AE's COS study based on the TY 2014 revenue requirement and the recommended cost allocation methodologies. More detailed information on the results is provided in Schedule G and associated work papers of Appendix G.

5.2. COST FUNCTIONALIZATION

The first step in AE's Cost of Service analysis is to functionalize the revenue requirement into the various utility functions — production, transmission, distribution, and customer service —, a process

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

[89] Energy-related costs are those costs that vary with the amount of electricity sold to, or transmitted for, customers. Costs related to supply are classified as energy-related to the extent they vary with the amount of electricity purchased or generated by the utility for its customers.

that effectively unbundles these costs and then sub-functionalizes costs within each function. These functions represent the products and services provided by the utility. In theory, each utility function faces unique market environments, business risks, and objectives; therefore, cost drivers are unique to each function, an important factor reflected in the rate design. Figure 5.1 summarizes the distinctive characteristics of each of AE's functions.

Figure 5.1
Major Utility Functions of Austin Energy

Function	Market Environment	Business Risk	Key Drivers
Production	Competitive	High	Availability and Low Cost
Transmission	Regulated by PUCT	Low	System Reliability and Open Access
Distribution	Locally Regulated by the COA	Medium	System Reliability
Customer Service	Locally Regulated by the COA	Medium	Customer Satisfaction and Responsiveness

Cost assignment by function falls into two general categories: 1) direct assignments and 2) derived allocations. Direct assignments are costs that are readily identifiable to a specific utility function and are directly assigned to that function. For example, fuel is an expense solely related to the production function, and thus it is directly assigned to that function.

Derived allocators are allocation factors based on the sum, average, or weighted effect of different underlying factors. Derived allocators can be complex but should reflect the logical answer to the question: what underlying activities drive the cost of this item? For example, administrative expenses are associated with the management and operation of all utility functions and thus are incurred throughout the utility in each function. Many administrative activities are associated with the management of utility staff, and these expenses are typically allocated to each function based on labor cost, which can be measured by the "level of effort"[90] by function. The PUCT has established guidelines on the allocation of administrative costs in required Transmission Cost of Service (TCOS) filings and in general, AE developed the derived allocators used in this COS study in accordance with these guidelines.

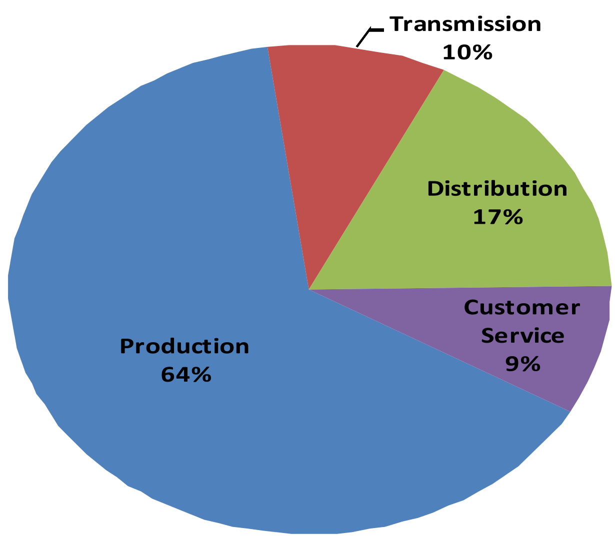
[90] Measures of level of effort include employee salaries and number of employees.

Using this approach, the TY 2014 revenue requirement was unbundled into the four functional areas. The results of this unbundling are summarized in Figure 5.2 and illustrated in Figure 5.3.

Figure 5.2
Unbundled Test Year 2014 Revenue Requirement

Function	Amount ($)	Average $/MWh Sold	% of Total
Production	784,030,818	71,361.71	64.4
Transmission	116,855,952	10,636.11	9.6
Distribution	211,966,421	19,292.98	17.4
Customer Service	104,374,119	9,500.03	8.6
Total	**1,217,227,310**	**110,790.83**	**100.0**

Figure 5.3
Test Year 2014 Revenue Requirement by Function



5.2.1. Production Function

As discussed in Chapter 3, Austin Energy no longer serves its customer load with its own generation. Rather, all power is purchased in the ERCOT market and then delivered to the Austin Energy load zone. In the Nodal market, the energy generated by Austin Energy serves as a physical and financial hedge against ERCOT market power price fluctuations, providing a direct benefit to AE's customers. Specifically, Austin Energy's diverse fuel types and technologies provide AE's customers with a vital risk management strategy that guards against exposure to the volatility of the wholesale market.

Maintaining a diverse resource portfolio is a key risk management strategy because any resource can experience cost fluctuations in any year. Additionally, different resources are designed to supply power in different ways to meet the fluctuating ERCOT wholesale market requirements over the course of the day and the course of the year.

Production costs include fuel and purchased power expenses; certain Operating and Maintenance expenses; and expenses related to the financing, repair, and replacement of AE's power generation resources. These costs can be divided generally into two separate categories: variable costs and fixed costs. Variable costs are driven by expenses that change as the output from individual resources change, like the cost of fuel. Conversely, fixed costs do not vary with the output of a resource. Expenses like debt service, staffing costs, and regular maintenance not associated with total hours of operations are grouped together as fixed costs.

The utility's variable operating costs are recovered through the sale of energy into the ERCOT wholesale market. Austin Energy then passes this revenue on to customers through the Power Supply Adjustment.[91] However, revenues from sales into the ERCOT wholesale market are not treated as a recovery mechanism for the fixed costs associated with AE's generation. Instead, Austin Energy recovers these fixed costs through base retail rates assigned to its customers and the production function is used to appropriately assign the fixed operating costs to the appropriate customer classes.

5.2.1.1. Sub-Functionalization

Prior to 2010, Austin Energy dispatched its plants to meet service territory load throughout the year. That is no longer the case. Now AE's power generating resources operate within the framework of the ERCOT wholesale market. Plants are dispatched when their marginal operating costs are lower than the market clearing price. Austin Energy's cost of service model classifies plant as demand-related, energy-related, or other. Production costs are sub-functionalized into categories based on the fuel resource utilized, as follows:

- Nuclear
- Coal

[91] The Power Supply Adjustment is calculated each year based on the expected net ERCOT wholesale market settlements, anticipated fuel expenditures, and net costs associated with Austin Energy's Power Purchase Agreements. These items are totaled together, adjusted for any over- or under-recovery from the prior year's PSA revenues, and then allocated to customer classes. This rate review does not address the calculation of the PSA because the issue is addressed by the Austin City Council each year during the budget process.

- Natural Gas
- Quick Response — Natural Gas
- Renewable — Wind
- Renewable — Solar
- Renewable — Landfill Methane
- GreenChoice
- Economy — Purchased Power
- ERCOT Administration and Texas RE Fees
- Energy Efficiency Programs

These sub-functions represent the different types of fuel resources used to supply AE's various production plants and the related services for which AE incurs costs. The results of the functionalization and sub-functionalization of production are summarized in Figure 5.4 and the detailed results can be found in Appendix D.

Figure 5.4
Production Function Test Year 2014 Revenue Requirement

Production Sub-Function	TY 2014 ($)
Nuclear	149,730,182
Coal	160,994,059
Natural Gas	116,035,555
Quick Response – Natural Gas	54,344,565
Renewable – Wind	229,463,235
Renewable – Solar	6,654,547
Renewable – Landfill Methane	23,784
GreenChoice(1)	22,772,679
Economy – Purchased Power	3,646,336
ERCOT Administration Fees	6,838,000
Energy Efficiency Programs	33,527,875
Total	**784,030,818**

Note:

1) GreenChoice® reflects amount billed to customers.

5.2.2. Transmission Function

Austin Energy delivers electricity to homes and businesses through a series of transmission and distribution lines that make up the state of Texas' electric grid. While ERCOT oversees the operation of the statewide transmission system, Austin Energy owns and operates a portion of the grid, including transmission lines and substations as well as the local distribution system. Austin Energy operates 623 miles of 345-, 138-, 69-kV high voltage transmission lines and 14 transmission substations. These power lines and substations deliver bulk power over long distances to the state's local distribution systems. The transmission function includes all costs associated with operating and maintaining the transmission portion of the electric grid, including capital expenses.

The PUCT has exclusive jurisdiction over rates and terms and conditions for the provision of transmission services. The PUCT sets the rate AE is paid by those who use the transmission system and the rate AE pays as its share of statewide transmission costs. This "open access" transmission system allows consumers to access power from anywhere within the ERCOT market.

5.2.2.1. Transmission Cost of Service

Costs associated with operating and maintaining AE's transmission system, and the rates set to recover them, are established through the Transmission Cost of Service approval process regulated by the PUCT. Transmission Service Providers (TSP) apply to add transmission-related costs to their overall TCOS and request the PUCT set a dollar per kilowatt rate that enables the TSP to recover the transmission-related revenue requirement. Each year, the PUCT pools together the approved rates of all the TSPs and establishes a postage stamp rate, a single rate used to recover transmission service charges from Distribution Service Providers (DSP), like Austin Energy.[92] The amount a DSP must pay for their use of the transmission system is based on the DSP's average peak demand during the four summer months (June through September) using the four coincident peak (4CP) cost allocation methodology. This allocation of ERCOT's pooled transmission costs reflects AE's share of ERCOT transmission costs and is included in the retail rate study as a revenue requirement line item and functionalized as a transmission expense. These costs are recorded in FERC account 565 — Transmission by Others.

5.2.2.2. Sub-Functionalization

Because AE's transmission cost recovery is regulated by the PUCT through a separate process, only AE's share of the pooled ERCOT transmission costs booked as "Transmission by Others" is relevant for recovery within the retail rate structure. Therefore, sub-functionalization is not required for

[92] The 2015 TCOS postage stamp rate paid by Austin Energy and all other DSPs, as established in PUCT Docket No. 43881, was $46.4036 per kW. The 2016 rate is under consideration in PUCT Docket No. 45382. Austin Energy is paid as a TSP $1.1601 per kW by all other DSPs for their use of AE's transmission facilities, pursuant to PUCT Docket No. 42385.

transmission costs. The results of the functionalization of transmission costs are summarized in Figure 5.5, and the detailed results can be found in Schedule G and associated work papers of Appendix G.

Figure 5.5
Transmission Function Test Year 2014 Revenue Requirement

Transmission by Sub-Function	TY 2014 ($)
Transmission by Others	116,855,952

5.2.3. <u>Distribution Function</u>

Distribution facilities connect customers to the transmission grid, delivering the generated and transmitted power to the customers, and thereby meeting their electric demands. Austin Energy connects the ERCOT transmission grid to more than 457,000 customer accounts through the local distribution power grid using over 11,000 miles of distribution lines, 60 distribution substations, over 78,000 transformers, and approximately 150,000 poles. Delivery voltages range from primary voltage at less than 69,000 volts to secondary voltages at 220 or 110 volts. The distribution function includes all costs associated with operating and maintaining the distribution portion of the electric grid, including capital expenses. This function also encompasses all of the distribution lines and substations, transformers, and poles, as well as primary and secondary conductors and meters and installations on customer premises.

5.2.3.1. Sub-Functionalization

Distribution costs were sub-functionalized into categories based on voltage delivery and other customer infrastructure requirements. Specifically, the distribution function was sub-functionalized as follows:

- Primary — Substations, Poles, and Conductors
- Secondary — Poles and Conductors
- Transformers
- Services
- Load Dispatch
- Meters
- City-Owned Lighting

These sub-functions represent a variety of utility products and services for which AE incurs costs in order to provide customers with adequate and reliable power at all times. These results of the functionalization and sub-functionalization of distribution are summarized in Figure 5.6, and the detailed results can be found in Schedule G and associated work papers of Appendix G.

Figure 5.6
Distribution Function Test Year 2014 Revenue Requirement

Distribution Sub-Function	TY 2014 ($)
Primary – Substation, Poles & Conductors	101,162,869
Secondary – Poles & Conductors	37,984,177
Transformers	19,452,892
Services	(1,213,738)
Load Dispatch	19,925,760
Meters	23,193,593
City-Owned Lighting	11,460,868
Total	**211,966,421**

In the above figure, the sub-functionalization of distribution services is a negative number as non-rate revenues associated with service extensions exceed the cost of this sub-function, thereby resulting in a negative value.

5.2.4. Customer Service Function

The customer service function includes all aspects of operations needed to meet customer support requirements. There are many separate business functions within AE's customer service function, including but not limited to billing services, customer care, key accounts, operations engineering, revenue measurement, quality management, and customer service management. Specific customer service support units are described in extensive detail in Chapter 3.

5.2.4.1. Sub-Functionalization

Customer service costs were sub-functionalized into the following specific service:

- Customer Accounting
- Customer Service
- Meter Reading

- Uncollectibles[93]
- Key Accounts
- Economic Development

These sub-functions represent a variety of products and services for which AE incurs costs in order to provide customers with excellent customer service. The results of the functionalization and sub-functionalization of customer service are summarized in Figure 5.7, and the detailed results can be found in Schedule G and associated work papers of Appendix G.

Figure 5.7
Customer Service Function Test Year 2014 Revenue Requirement

Customer Service Sub-Function	TY 2014 ($)
Customer Accounting	33,317,497
Customer Service	20,733,391
Meter Reading	21,020,185
Uncollectibles	16,806,578
Key Accounts	3,406,039
Economic Development	9,090,429
Total	**104,374,119**

5.3. COST CLASSIFICATION

Once the cost functionalization step is complete, AE classifies costs in order to identify expenses by their underlying nature. Drivers of cost, such as electricity consumption, peak demand, and customer service needs, inform the decisions that Austin Energy makes when working to most fairly attribute costs across the customer classes. Typical cost classifications include demand-related costs that vary with customer peak usage or demand level (measured in kW), energy-related costs that vary with the amount of energy consumed by a customer (measured in kWh), customer-related costs (measured in number of customers), and revenue-related costs (measured by revenue requirement). Additionally, some costs can be directly assigned to a customer or customer class.

Generally, production costs are classified as either demand-related or energy-related. Transmission costs are typically classified as 100 percent demand-related with some direct assignments, while distribution costs are classified as either demand-related or customer-related with some direct assignments. Customer service costs are generally classified as customer-related.

[93] Uncollectibles can also be referred to as “bad debt.”

5.3.1. Demand-Related Costs

Considered fixed costs because they do not vary with consumption, demand-related costs are associated with the production, transmission, and distribution systems and represent the costs of meeting the overall electric demand on Austin Energy's system. Thus, demand-related costs are assigned to each customer class based on the class contribution to system demand.

For cost allocation purposes, class demands are determined at different points on the system for different functions. For the production function, AE is concerned with making generation available during the ERCOT system peak throughout the year; therefore, to allocate demand costs to each customer class, Austin Energy calculates each customer class' contribution to the twelve monthly peak days that occur from January through December. For the transmission function, AE is obligated by the PUCT to pay the other ERCOT transmission companies for transmission built to meet the ERCOT system peak; therefore, class demands coincident with ERCOT system peak are used to allocate cost to each customer class.[94] The distribution function is concerned with meeting localized demands; therefore, class maximum demands are often used to allocate distribution costs. Finally, for individual customers, AE is concerned with the maximum demand that the specific customer places on the system. These demands are significant cost drivers for AE's capital expenses, including debt.

5.3.2. Energy-Related Costs

Energy-related costs are expenses that vary with electricity consumption, with the most significant energy-related costs incurred by AE being fuel and energy market costs. Fuel and energy market costs are directly related to the amount of electricity consumed by AE's customers. The costs of coal, natural gas, renewables, and nuclear fuel expenses incurred by AE are all considered energy-related costs.

5.3.3. Customer-Related Costs

Customer-related costs are expenses that reflect the minimum amount of fixed costs that the utility needs to supply for customers to access the utility system. These are the cost of meters, service drops, meter reading, meter maintenance, and billing. These costs vary with the addition or subtraction of customers, not usage; therefore, they are properly considered customer-related costs, not demand-related or energy-related costs.

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[94] This approach is also consistent with the rules of the Public Utility Commission of Texas in computing transmission rates across the transmission service providers operating in ERCOT. *See*, PUCT Substantive Rule §25.192(b).

5.3.4. Revenue-Related Costs

Revenue-related costs are costs that vary with the amount of revenue generated by the utility. For example, Austin Energy's general fund transfer is a revenue-related cost because the transfer calculation is tied to the utility's revenues. Thus, the unbundling process classifies the general fund transfer across all functions and sub-functions based on revenue. Further, the cost associated with the Service Area Street Lighting class is ultimately allocated to customer classes based on revenue.

5.3.5. Direct Assignments

Direct assignments are costs easily assignable to a particular customer or customer class. For example, distribution assets associated with AE-owned lighting were directly assigned to the applicable lighting customer classes.

5.3.6. Cost Classification Results

In summary, production costs are classified as demand-related and energy-related. All transmission costs and most distribution costs are classified as demand-related. A small portion of distribution costs related to meters are classified as customer-related and an additional amount is directly assigned to applicable lighting customer classes. All customer service costs are classified as customer-related. These numeric results are included in Figure 5.8 with more detailed results in Schedule G and associated work papers of Appendix G.

Figure 5.8
Cost Classification of Test Year 2014 Revenue Requirement

Description	Demand	Energy	Customers	Direct Assignment[1]	Total
Production ($)	341,575,538	442,455,280	-	-	784,030,818
Transmission ($)	116,855,952	-	-	-	116,855,952
Distribution ($)	177,311,960	-	23,193,593	11,460,868	211,966,421
Customer Service ($)	-	-	104,374,119	-	104,374,119
Total Cost of Service ($)	**635,743,450**	**442,455,280**	**127,567,712**	**11,460,868**	**1,217,227,310**
Percentage of Total (%)	**52.2**	**36.3**	**10.5**	**0.9**	**100.0**

Note:

1) The Distribution direct assignment is related to Service Area Street Lighting.

5.4. COST ALLOCATION

The final step in AE's COS analysis is cost allocation. Allocation factors are developed for demand-related, energy-related, and customer-related costs. AE then applies these factors to distribute classified costs to each customer class according to the class' contribution to that cost. Each allocation factor is developed to be consistent with each cost classification methodology applied. For example, costs classified as energy-related are allocated to each customer class based on the electricity used by that customer class.

For the purpose of performing AE's allocated COS study, costs were allocated to the following proposed AE customer classes described in Chapter 2:

- Residential
- Secondary Voltage <10 kW — (S1)
- Secondary Voltage 10 kW — <300 kW — (S2)
- Secondary Voltage ≥300 kW — (S3)
- Primary Voltage <3 MW — (P1)
- Primary Voltage 3 MW — <20 MW — (P2)
- Primary Voltage ≥20 MW — (P3)
- Transmission Voltage — (T1)
- Transmission Voltage ≥20 MW @ 85% Load Factor — (T2)
- Service Area Street Lighting[95]
- City-Owned Private Outdoor Lighting[96]
- Customer Owned Non-Metered Lighting[97]
- Customer Owned Metered Lighting[98]

5.4.1. Demand-Related Cost

Demand-related costs are expenses that are driven by the overall demand on the system. Costs classified as demand-related are associated with the production, transmission, and distribution functions. Within each function, the allocation of demand-related costs to each customer class was based on accepted industry practices that seek to assign costs to each class in alignment with the way

[95] Service Area Street Lighting is a community benefit cost that is allocated to other customer classes in a later step in the Cost of Service process.

[96] For example, security lighting at distribution substations falls within this class.

[97] For example, traffic lights fall within in this class.

[98] For example, sports fields lighting falls within this class.

costs are incurred by the utility. The class allocation factors developed for these functions are discussed below.

5.4.1.1. <u>Production – Demand</u>

Production demand cost allocation methods vary depending upon historical precedent and the utility's view of the underlying nature and causation of generation capacity. In development of the production demand-related cost allocation methodology used in this study, AE reviewed a variety of allocation methods described in NARUC's Cost of Service manual.

In the 2012 rate ordinance, City Council adopted a modified version of the Average and Excess (A&E) 4CP method to allocate production demand costs.[99] This methodology allocates production expenses to customer classes in proportion to class contribution to system peak demand in each of the four summer months. This methodology is more applicable to vertically integrated utilities which dispatch their own generation resources to serve their own load. Austin Energy operated in a similar manner during TY 2009. In that environment, it is reasonable to allocate the expense of the generation fleet to the customers primarily responsible for driving peak demand and the investment in additional generating capacity.

In ERCOT's Nodal market, Austin Energy owns, maintains, and operates its generation fleet in order to participate in the wholesale market. By doing so, AE helps protect its customers from volatile wholesale market prices by selling production from its fleet into the market whenever prices exceed the cost of running generation. Due to high market offer caps and risks of pricing volatility, AE has opportunities to use its entire fleet throughout the year, not just during the peak demand season.[100]

All Load Serving Entities — including Austin Energy — procure the energy needed to serve their customers' load from the ERCOT wholesale market. Austin Energy passes the cost of serving its load from the wholesale market to its customers through the PSA. It also passes the benefit of the revenue it makes from selling the energy from its generation fleet back to its customers through the PSA.

Austin Energy proposes to use the ERCOT 12 Coincident Peak (ERCOT 12CP) methodology to functionalize the cost of generation because this allocation methodology better aligns the relationship between the costs and the benefits that accrue from owning and operating its fleet. As noted, the benefits and some of the costs flow back to its customers through the PSA. This methodology allocates

[99] City of Austin Ordinance No. 20120607-055, Part 6, (June 7, 2012).

[100] Please see Chapter 3 for a more extensive discussion of the role of Austin Energy's generation fleet in the ERCOT wholesale market.

production expenditures to customer classes based on each class' contribution at the time of the ERCOT system peak demand during each of the 12 calendar months. Applying this methodology recognizes that all of AE's customers benefit from AE's generation fleet year round.

Figure 5.9 provides the cost allocation for the production function demand-related costs associated with AE's physical resources.

Figure 5.9
Production Function Demand-Related Cost Allocation
Comparison Based on Allocation Method

Customer Class	Demand Related Costs ($) ERCOT 12 CP
Residential	143,595,666
Secondary Voltage <10 kW	7,305,647
Secondary Voltage 10 - <300 kW	73,130,402
Secondary Voltage ≥300 kW	63,724,119
Primary Voltage <3 MW	11,569,225
Primary Voltage 3 - <20 MW	12,489,115
Primary Voltage ≥20 MW	24,536,541
Transmission Voltage	194,821
Transmission Voltage ≥ 20 MW @ 85% aLF	4,201,648
Service Area Street Lighting	595,892
City-Owned Private Outdoor Lighting	176,163
Customer Owned Non-Metered Lighting	14,303
Customer Owned Metered Lighting	41,996
Total	**341,575,538**

5.4.1.2. Transmission – Demand

As previously discussed, AE's transmission costs are regulated by the PUCT and represent a statewide average cost to customers. ERCOT-wide transmission costs are recovered from all utilities interconnected with the transmission system based on each utility's load ratio share of the ERCOT summer peak. That share is computed using the 4CP method described earlier. The 4CP method calculates the utility's average coincident system demand at the point of ERCOT system peak in each of the four summer months — June through September — as reported by ERCOT. These calculated transmission costs are then distributed among each AE customer class by AE in a similar fashion. This creates a direct cause and effect relationship between assignment to AE of statewide transmission costs and allocation among AE's customer classes.

Figure 5.10 summarizes the customer class cost allocations for the transmission function's demand-related costs. This allocation represents 100 percent of the costs in the transmission function, which are all associated with transmission of electricity by others.

Figure 5.10
Transmission Function Demand-Related Cost Allocation

Customer Class	Demand-Related Costs ($)
Residential	50,844,009
Secondary Voltage <10 kW	2,163,889
Secondary Voltage 10 - <300 kW	25,219,393
Secondary Voltage ≥300 kW	21,302,324
Primary Voltage <3 MW	4,277,318
Primary Voltage 3 - <20 MW	3,787,003
Primary Voltage ≥20 MW	7,844,104
Transmission Voltage	0
Transmission Voltage ≥ 20 MW @ 85% aLF	1,399,810
Service Area Street Lighting	4,549
City-Owned Private Outdoor Lighting	-
Customer Owned Non-Metered Lighting	-
Customer Owned Metered Lighting	13,553
Total	**116,855,952**

5.4.1.3. Distribution – Demand

As noted earlier, distribution systems distribute power to customers through a series of poles, wires, substations, conductors, and transformers, and the systems are designed to meet maximum localized demands. Austin Energy uses two allocation methodologies to assign distribution function demand related expenses to customers.

5.4.1.3.1 12NCP Method

Distribution facilities such as substations that directly interconnect with the transmission system are designed to meet the aggregated customer loads in a specific geographic area. As the system is designed to meet localized demand, these costs are most appropriately allocated by analyzing the magnitude and timing of the class peak, which often occurs at times different than the system peak. Because the class peak often does not align with the system peak, it is considered non-coincident with the system peak and referred to as the class non-coincident peak (NCP). The 12NCP method takes the average of each class' NCP for all 12 months. This method represents the annual average class peak and was used to allocate costs associated with distribution load dispatch, distribution substations, poles, and conductors at both the primary and secondary voltage levels.

5.4.1.3.2 Sum of Maximum Demands

As power moves through the distribution facilities into local neighborhoods and business parks, infrastructure such as transformers and service extensions are designed to meet the maximum demand of the customer in each household or business. The end-user demand is best reflected in a cost of service analysis as billed demand. Billed demand is the measure of estimated maximum demand a customer places on the system at any time during the month. This allocator represents the annual average customer peak for each class and is commonly referred to as the sum of maximum demands. The sum of maximum demands allocator was used to allocate costs associated with transformers and service extension costs.

Figure 5.11 summarizes the customer class cost allocations for the distribution function demand-related costs.

Figure 5.11
Distribution Function Demand-Related Cost Allocation

Customer Class	Demand-Related Costs ($)
Residential	81,382,066
Secondary Voltage <10 kW	4,110,453
Secondary Voltage 10 - <300 kW	39,208,940
Secondary Voltage ≥300 kW	33,460,926
Primary Voltage <3 MW	4,124,652
Primary Voltage 3 - <20 MW	4,805,478
Primary Voltage ≥20 MW	8,618,968
Transmission Voltage	28,976
Transmission Voltage ≥ 20 MW @ 85% aLF	243,243
Service Area Street Lighting	766,999
City-Owned Private Outdoor Lighting	296,453
Customer Owned Non-Metered Lighting	39,879
Customer Owned Metered Lighting	224,927
Total	**177,311,960**

As shown above, customers are only allocated distribution system costs associated with the infrastructure that they use. Customers that are connected directly to the transmission system bypass the distribution system and thus are not allocated distribution costs.[101] Customers connected to the primary voltage distribution system are allocated infrastructure costs incurred at primary voltages and higher. Secondary voltage customers are allocated costs associated with the entire distribution system.

5.4.2. Energy-Related Cost

Energy allocation methods are used to allocate energy-related costs such as fuel costs. Compared to other types of allocation factors, energy allocation factors are relatively straightforward, as they are only applied to the production function. Energy consumption by customer class is readily available for use in the development of these allocation factors.

When transmitting and distributing electricity, a certain percentage of energy is lost due to resistance. In general, losses are estimated by calculating the discrepancy between energy produced and energy sold to customers. On average, system losses tend to be around three to seven percent. This variance is a result of different delivery voltages and infrastructure requirements serving customers. Customers served at higher delivery voltages have lower line losses than customers served at lower delivery voltages.

Line and transformer losses at different service voltage levels were determined by a system loss study[102] completed for the 2012 Cost of Service and Rate Review process. The study determined the percentage losses that occur at each voltage level at which AE customers take service. Line and transformer losses by voltage level using the 2011 Line Loss Study results taken in conjunction with information about overall system losses results in amounts shown in Figure 5.12. At the system level, each customer class' metered energy sales, adjusted for the proper level of line losses depending on service voltage, were used to derive a Net Energy For Load (NEFL) energy allocation factor. NEFL represents the amount of energy that needs to be produced at the power plants to service customers at the point of the meter.[103]

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[101] Some nominal costs associated with dispatching load are passed on to transmission level customers through the distribution function.

[102] Appendix J - *Transmission and Distribution Loss Study*, R.W. Beck, Hendersonville, TN (February 17, 2011).

[103] NEFL is the energy, in kWh, used by each customer class adjusted to account for transformation losses at the different service voltage levels. Put another way, this is the energy needed at the generator to supply the load plus losses.

Figure 5.12
Line and Transformer Losses By Delivery Voltage Level

Delivery Voltage	Losses (%)
Transmission	1.60
Primary	2.85
Secondary	5.05
System Average	4.60

Customers connected directly to the transmission system are only allocated transmission losses, customers connected to the primary distribution system are allocated transmission and distribution primary losses, and customers connected to the secondary distribution system are allocated losses for all three components of the system.

Figure 5.13 summarizes the customer class cost allocations for the production function energy-related costs.

Figure 5.13
Production Function Energy-Related Cost Allocation

Customer Class	Energy-Related Costs ($)
Residential	146,511,353
Secondary Voltage <10 kW	9,021,373
Secondary Voltage 10 - <300 kW	93,631,520
Secondary Voltage ≥300 kW	92,885,182
Primary Voltage <3 MW	21,159,262
Primary Voltage 3 - <20 MW	24,126,518
Primary Voltage ≥20 MW	44,911,636
Transmission Voltage	769,503
Transmission Voltage ≥ 20 MW @ 85% aLF	7,638,054
Service Area Street Lighting	1,214,566
City-Owned Private Outdoor Lighting	429,363
Customer Owned Non-Metered Lighting	59,713
Customer Owned Metered Lighting	97,237
Total	**442,455,280**

5.4.3. Customer-Related Cost

The distribution and customer service functions each include customer-related costs. The distribution function contains customer-related costs related to metering. In the customer service function, all costs are classified as customer-related. These costs are allocated to each customer class by applying customer allocation factors discussed below.

5.4.3.1. <u>Distribution – Customer</u>

Metering costs are dependent on the type of meter installed and the data gathered from those meters for billing and other purposes. Metering requirements can vary by customer class with the most expensive meters generally being used by large commercial and industrial customers. In order to properly allocate meter costs to each customer class, a weighted customer meter factor was developed to account for cost differentials in metering equipment. The customer weighting meter factor was developed considering the number of customers and meter costs — installation labor, meter, socket, and instrument transformers — by rate schedule. Weighting factors by meter type are shown in Figure 5.14.

Figure 5.14
Meter Weighting Factors

Customer Class	Meter Weighting Factor
Residential	1
Secondary Voltage <10 kW	2.3
Secondary Voltage 10 - <300 kW	2.3
Secondary Voltage ≥300 kW	2.7
Primary Voltage <3 MW	10.0
Primary Voltage 3 - <20 MW	10.0
Primary Voltage ≥20 MW	10.0
Transmission Voltage	624.0
Transmission Voltage ≥ 20 MW @ 85% aLF	624.0
Metered Lighting	1.0

Figure 5.15 summarizes the customer class cost allocations for the distribution function customer-related costs.

Figure 5.15
Distribution Function Customer-Related Cost Allocation

Customer Class	Customer-Related Costs ($)
Residential	18,028,827
Secondary Voltage <10 kW	2,993,291
Secondary Voltage 10 - <300 kW	1,851,085
Secondary Voltage ≥300 kW	142,571
Primary Voltage <3 MW	47,907
Primary Voltage 3 - <20 MW	8,924
Primary Voltage ≥20 MW	1,409
Transmission Voltage	87,545
Transmission Voltage ≥ 20 MW @ 85% aLF	29,182
City-Owned Private Outdoor Lighting	-
Customer Owned Non-Metered Lighting	-
Customer Owned Metered Lighting	2,853
Total	**23,193,593**

5.4.3.2. Customer Service – Customer

Customer service functions include customer accounting (billing and collections), customer service, meter reading, and key accounts. Uncollectible accounts, the cost associated with unpaid bills, is also included in this function.

To allocate expenses related to customer accounting, customer service, and meter reading, Austin Energy developed a customer allocation factor that totals the number of customers receiving service for each month within the test year by customer class. This factor is referred to as Customer Months.

For key accounts and uncollectible accounts, AE developed customer allocation factors that reflect the varying cost levels associated with each customer class. For example, the cost of key accounts varies by customer class as some customer classes require additional effort while other customer classes are rarely served by the Key Accounts staff. Austin Energy considered this varying level of effort when developing customer class weighting factors for these costs. Customer class weighting factors were determined through discussions with AE supervisors responsible for these services. Weighting factors by customer service function are shown in Figure 5.16.

Figure 5.16
Customer Service Function Weighting Factors

Customer Class	Key Accounts	Uncollectibles
Residential	0	2.54
Secondary Voltage <10 kW	1	1.00
Secondary Voltage 10 - <300 kW	3	3.96
Secondary Voltage ≥300 kW	153	n/a
Primary Voltage <3 MW	175	n/a
Primary Voltage 3 - <20 MW	2,657	n/a
Primary Voltage ≥20 MW	5,147	n/a
Transmission Voltage	2,079	n/a
Transmission Voltage ≥ 20 MW @ 85% aLF	6,236	n/a
Lighting Classes	n/a	n/a

Figure 5.17 summarizes the cost allocation by class for the customer-related costs. Customer-related costs represent 100 percent of the customer service function costs.

Figure 5.17
Customer Service Function Customer-Related Cost Allocation

Customer Class	Customer-Related Costs ($)
Residential	82,256,627
Secondary Voltage <10 kW	6,350,355
Secondary Voltage 10 - <300 kW	5,759,696
Secondary Voltage ≥300 kW	6,517,031
Primary Voltage <3 MW	658,001
Primary Voltage 3 - <20 MW	1,817,473
Primary Voltage ≥20 MW	555,445
Transmission Voltage	224,625
Transmission Voltage ≥ 20 MW @ 85% aLF	224,278
Service Area Street Lighting	-
City-Owned Private Outdoor Lighting	-
Customer Owned Non-Metered Lighting	-
Customer Owned Metered Lighting	10,588
Total	**104,374,119**

5.4.4. Revenue-Related Costs

To allocate Service Area Lighting and Energy Efficiency programs, Austin Energy used revenue-related allocation factors that distribute the cost levels associated with each customer class. Ultimately, these expenses are removed from the base revenue requirement and collected through the Community Benefit Charge.

5.4.5. Direct Assignments

Some costs can be directly assigned to a customer class. Costs associated with AE-owned lighting distribution assets were directly assigned to the appropriate lighting customer classes. Figure 5.18 summarizes this direct assignment of lighting costs to the appropriate lighting customer classes.

Figure 5.18
Distribution Function Direct Assignment of Lighting Costs

Customer Class	Direct Assignments ($)
Residential	-
Secondary Voltage <10 kW	-
Secondary Voltage 10 - <300 kW	-
Secondary Voltage ≥300 kW	-
Primary Voltage <3 MW	-
Primary Voltage 3 - <20 MW	-
Primary Voltage ≥20 MW	-
Transmission Voltage	-
Transmission Voltage ≥ 20 MW @ 85% aLF	-
Service Area Street Lighting	8,621,148
City-Owned Private Outdoor Lighting	2,839,721
Customer Owned Non-Metered Lighting	-
Customer Owned Metered Lighting	-
Total	**11,460,868**

5.4.6. Cost Allocation Summary

Cost allocation factors considered in AE's COS analysis are summarized in Figure 5.19 for reference.

Figure 5.19
Allocation Factors

Allocation Factors	Description
Demand-Related Costs	
Production Function	
ERCOT 12CP	The 12CP allocator allocates demand costs based upon each class' contribution to the 12 monthly ERCOT system coincident peaks.
Transmission Function	
4CP ERCOT Peak (Required)	The 4CP allocator represents each class' contribution to the EROCT peak during the four peak months of the year (June-September).
Distribution Function	
12NCP (Recommended for Certain Costs)	The 12 NCP allocator allocates demand costs to customer classes based on the ratio of the average class peak for each month of the year, not necessarily coincident with the system peak, to the sum of average class peak demands for all customer classes.
Sum of Maximum Demands (Recommended for Certain Costs)	The sum of maximum demands allocator accounts for the individual customer's highest demands placed on the system. The sum of maximum demands incorporates the total maximum demand by customer class and apportions each customer class' total to the system total.
Energy-Related Costs	
Production Function	
NEFL (Recommended for Certain Costs)	kWh sold by class adjusted for system losses (i.e., energy at generation)
Kilowatt-Hours Sold (Recommended for Certain Costs)	kWh sold by class
Customer-Related Costs	
Distribution Function	
Weighted Customer - Meters (Recommended for Certain Costs)	Number of customer-months weighted for meter investment
Customer Service Function	
Number of Customer Months (Recommended for Certain Costs)	The sum of the number of customers receiving service for each month of the year
Weighted Customer - Uncollectibles (Recommended for Certain Costs)	Number of customer-months weighted for bad debt
Weighted Customer - Key Accounts (Recommended for Certain Costs)	Number of customer-months weighted for key account activities
Revenue-Related Costs	
Revenue Requirement (Recommended for Certain Costs)	% of Revenue Requirement
Revenue Requirement Excluding Street Lighting (Recommended for Certain Costs)	% of Revenue Requirement, excluding service area street lighting

5.5. COST OF SERVICE RESULTS

AE's total Cost of Service study results are presented in Figure 5.20. The COS results are compared to estimated revenues based on existing retail rates. The difference between the COS results and the projected total revenues for each customer class demonstrates the customer class' disparity to its total cost of service. A deficiency in revenue indicates the class does not contribute enough revenue to meet its total cost of service. Similarly, an excess in total revenues indicates the class contributes more than its total cost of service. Figure 5.20 summarizes the total COS results by customer class using total revenue requirement with the detailed COS results as provided in Schedule G and associated work papers of Appendix G.

Figure 5.20
Existing Base Rate Changes Needed to Meet Total Cost of Service by Customer Class

Customer Class	Total Cost of Service(1) ($)	Existing Base Rates and Test Year Pass-Through Rates(1) ($)	Excess/ (Deficient) Revenue(2) ($)	Increase/ (Decrease) Needed to Meet Cost of Service (%)
Residential	527,473,323	474,062,283	(53,411,041)	11.3
Secondary Voltage <10 kW	32,241,755	31,458,282	(783,472)	2.5
Secondary Voltage 10 - <300 kW	241,019,337	283,339,669	42,320,332	(14.9)
Secondary Voltage ≥300 kW	220,057,525	238,491,828	18,434,303	(7.7)
Primary Voltage <3 MW	42,224,997	46,257,714	4,032,717	(8.7)
Primary Voltage 3 - <20 MW	47,471,430	52,185,478	4,714,048	(9.0)
Primary Voltage ≥20 MW	87,271,333	89,945,727	2,674,394	(3.0)
Transmission Voltage	1,317,596	2,146,390	828,794	(38.6)
Transmission Voltage ≥ 20 MW @ 85% aLF	13,863,814	13,517,421	(346,394)	2.6
Service Area Street Lighting	N/A	N/A	N/A	N/A
City-Owned Private Outdoor Lighting	3,776,457	2,884,834	(891,623)	30.9
Customer Owned Non-Metered Lighting	114,954	108,555	(6,399)	5.9
Customer Owned Metered Lighting	394,788	303,428	(91,360)	30.1
Total	**1,217,227,310**	**1,234,701,609**	**17,474,299**	**(1.4)**

Notes:

1) Excludes Customer Assistance Program funding.

2) Only shows base revenue differences and none of the impacts of pass-through charges.

These results highlight that the residential customer class is under-recovering by approximately \$53.4 million, while the majority of non-residential customer classes are over-recovering by approximately \$73 million, some by a substantial margin.

5.6. COST OF SERVICE STUDY CONCLUSIONS

The COS study results demonstrate that progress bringing customer classes closer to cost of service has been made since the TY 2009 COS study, even if significant disparities remain. While the residential class remains well below its total cost of service, rate adjustments over the past three years have nearly cut in third the class' total deficiency.[104] That said, continuing work is needed to make more progress toward aligning all classes with their total cost of service. Austin Energy's recommended revenue requirement is designed to move classes toward their COS without producing unacceptably large customer impacts. Austin Energy also recognizes that the current economic and affordability conditions in AE's service area could not support a complete shift to full cost of service or the accompanying rate shock such an immediate change would cause. Therefore, AE applies a moderate approach to address COS imbalances in order to mitigate rate shock. Fortunately, with $17.5 million in revenue reductions available in this rate review, Austin Energy is able to address some of the commercial customer classes' over-recovery.

The process to design rates that reduce annual base rate recovery by $17.5 million considered several factors including the current COS recovery, implications of proposed changes to pass-through charges, and the desire to impose a rational progression of rates as customer loads increase. The first objective was to ensure that no increases were imposed on class revenue requirement. Customer classes that the COS study indicated needed an increase in base rates — primarily Residential and S1 — were held revenue neutral, except for T2. In the fall 2015, Austin Energy designed the T2 rates to recover the full COS. AE maintained this principle even though the T2 existing customers are under contract and will not have their base rates changed in the next few years. By keeping the T2 class at 100 percent COS, the remaining customer classes are able to receive more immediate benefit from the revenue reduction.

With this in mind, the proposed base rates for the S2 and S3 customer classes received a $10.1 million reduction in annual base revenues. S2 received the vast majority of that $10 million benefit — approximately $8.3 million — given its overall disparity to class COS and given the large number of customers assigned to the class. The remaining $7 million reduction primarily benefits the P1, P2 and P3 classes. Rather than distribute a pro rata share of the reduction to each customer class reflective of the COS results, AE recognized the impacts of estimated pass-through charges. The P2 rate class is set to receive a large change to the Regulatory Charge in order to restore a logical rate design for the class as it compares with the Regulatory Charge assessed on the P1 and P3 classes. Left on its own, this change in the Regulatory Charge would result in a significant bill increase for P2 customers, an illogical result given

[104] In the 2009 COS study, the residential class was under-recovered by approximately $78 million.

the overall context of a revenue decrease. Therefore, P2 received a larger share of the remaining $7 million as an offset to what would have been an overall bill increase.

Finally, AE considered the need for a logical progression in rates from one tariff to the next as customer loads increase. In other words, as overall customer demand increases, the proposed base rates result in progressively higher demand charges as the size of the customer loads increase. This is consistent with the COS as well as AE's objective to incentivize large customers to improve their load factor. As the redesigned demand charges reflect a steady, logical progression from S2 through P3, the charges increase from one class to the next higher class. Correspondingly, each customer class' energy charges were set in recognition of the demand charges, and reduced as demand charges increased.

Based on these considerations, Austin Energy recommends another gradual step that will help align each customer class' revenue recovery closer to the customer class' cost of service and minimize some interclass subsidies. Austin Energy's ratemaking principles suggest a continuing and gradual move towards COS; therefore, the recommended rates emphasize the customer class relationship to COS and customer bill impacts. The proposed Cost of Service, including the $17.4 million reduction in revenue, is shown in Figure 5.21. Austin Energy uses the results in Figure 5.21 as the foundation for developing the year one rate changes that are proposed in Chapter 6. Deliberations about future year adjustments should occur throughout the Impartial Hearing Examiner process.

Figure 5.21
Proposed Base Rate Changes Needed to Meet Total Cost of Service by Customer Class

Customer Class	Total Cost of Service[1] ($)	Existing Base Rates and Test Year Pass-Through Rates[1] ($)	Excess/ (Deficient) Revenue[2] ($)	Increase/ (Decrease) Needed to Meet Cost of Service (%)	Change from Existing to Proposed Base Rates ($)	Proposed Base Rates and Test Year Pass-Through Rates[1][3] ($)	Excess/ (Deficient) Revenue[2] ($)	Increase/ (Decrease) Needed to Meet Cost of Service (%)
Residential	527,473,323	474,062,283	(53,411,041)	11.3	4,626	474,057,657	(53,415,666)	11.3
Secondary Voltage <10 kW	32,241,755	31,458,282	(783,472)	2.5	17,249	31,441,033	(800,722)	2.5
Secondary Voltage 10 - <300 kW	241,019,337	283,339,669	42,320,332	(14.9)	8,295,392	275,044,277	34,024,940	(12.4)
Secondary Voltage ≥300 kW	220,057,525	238,491,828	18,434,303	(7.7)	1,805,488	236,686,340	16,628,815	(7.0)
Primary Voltage <3 MW	42,224,997	46,257,714	4,032,717	(8.7)	1,915,842	44,341,872	2,116,875	(4.8)
Primary Voltage 3 - <20 MW	47,471,430	52,185,478	4,714,048	(9.0)	3,767,215	48,418,263	946,833	(2.0)
Primary Voltage ≥20 MW	87,271,333	89,945,727	2,674,394	(3.0)	1,934,504	88,011,223	739,889	(0.8)
Transmission Voltage	1,317,596	2,146,390	828,794	(38.6)	17,296	2,129,093	811,497	(38.1)
Transmission Voltage ≥ 20 MW @ 85% aLF	13,863,814	13,517,421	(346,394)	2.6	(346,341)	13,863,762	(52)	0.0
Service Area Street Lighting	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
City-Owned Private Outdoor Lighting	3,776,457	2,884,834	(891,623)	30.9	0	2,884,834	(891,623)	30.9
Customer Owned Non-Metered Lighting	114,954	108,555	(6,399)	5.9	0	108,555	(6,399)	5.9
Customer Owned Metered Lighting	394,788	303,428	(91,360)	30.1	17	303,411	(91,377)	30.1
Total	**1,217,227,310**	**1,234,701,609**	**17,474,299**	**(1.4)**	**17,411,290**	**1,217,290,318**	**63,009**	**(0.0)**

Notes:

1) Excludes Customer Assistance Program funding.
2) Only shows base revenue differences and none of the impacts of pass-through charges.
3) The $63,009 in excess revenue is due to rounding.

6. RATE DESIGN MODIFICATIONS

After determining the utility's revenue requirement and completing the Cost of Service analysis, utilities take the final step in the ratemaking process, called rate design. Rate design refers to a structure of rates and charges developed to collect the required revenue in accordance with all applicable policy decisions and pricing objectives. The structure of rates refers to the unit charges and customer consumption measures used to calculate individual bills. In most cases, utility rates include fixed charges that do not vary with customer usage, often called customer charges or basic charges, and one or more charges assessed per unit of demand or energy.

6.1. APPROACH TO SETTING FAIR RATES

The Cost of Service study provides a benchmark for determining the fairness of rates as it establishes the costs incurred by the utility to support each customer class. However, as a COS study grows out-of-date with time, deviations between recovery of class revenue and class cost of service can occur. Austin Energy conducted its last COS study using financial information from FY 2009, and City Council established new rates for each customer class that became effective October 1, 2012. This new structure encompassed significant changes to customer classes and the charges for electric service.

Since 2012, as part of the City's annual budget process, AE has adjusted the pass-through rates, but the base rates have remained the same.[105] During this time period, AE analyzed how effective the rate structures were at recovering the total revenue requirement while meeting the policies and principles used to develop the rates, and as Chapter 5 described, customer class revenues under existing rates deviate from cost of service by varying amounts. Thus, in fairness to all the utility's customers, to the utility itself, and to the City of Austin, reviewing the rate design and updating certain components is now warranted.

In designing rates, public power utilities like AE consider many factors including the results of a cost of service study, the priorities of the community, and the economic health of the utility. Rates may deviate from the cost of service results within each class irrespective of the total class cost of service in order to meet various social and policy objectives of the utility and the community. For example, AE has historically provided discounts to low-income customers. Providing such a discount requires that the

[105] The current City of Austin Electric Tariff that took effect November 1, 2015 provides a description of existing customer classes, rates, fees, available discounts, and a glossary of terminology and is included here in Appendix K.

utility collect the discounted cost from other ratepayers. It is important, therefore, to recognize the potential of creating intra- or inter-class subsidies when applying policy priorities to the rate design.

The utility's strategic objectives, reflected in AE's mission statement and Strategic Plan, serve as a guide for making business and policy decisions. It is critical that the utility's rate structures align with the utility's strategic objectives to ensure the continued financial strength of the utility and the successful implementation of the utility's goals and initiatives. For example, in order to achieve AE's goal of 900 MW of energy efficiency by 2025, AE's rate structures need to be designed to encourage customers to consume electricity efficiently. However, it is important that meeting this goal does not come at the detriment of the utility's financial health. Thus, rate structures must be established that ensure the utility meets its overall revenue requirement while considering projections of reduced customer energy consumption.

The art of ratemaking involves designing rates that balance inherently conflicting rate objectives in a manner that reflects community values. At a minimum, utility rates should be sufficient to generate revenues required to support operations, maintain and develop capital infrastructure, and preserve or enhance the financial integrity of the utility system. In addition, electric rates are set in accordance with long-standing principles, and state and local laws and policies. Austin Energy's rates philosophy was articulated in greater detail in Chapter 2.

Austin Energy believes current rates and rate structure fulfill the utility's stated rates principles. During this current proceeding AE focused on several key principles, including:

- Adherence to applicable laws and regulations;
- A transparent process with robust public involvement;
- Affordability for customers of all types;
- Fairness;
- Gradualism; and
- Maintaining financial integrity of the utility and thus the City of Austin.

Using these principles, Austin Energy can devise a fair plan to reduce overall base revenues by $17.5 million, bring most customer classes closer to cost of service, and continue providing useful and valuable services to its customers and the community at large.

6.2. BASIS FOR DETERMINING RATES

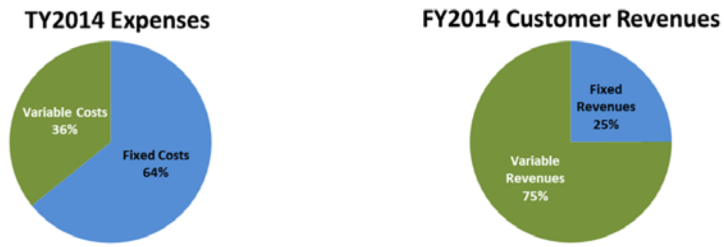
A key element uncovered in the COS study is the relationship between fixed versus variable costs and revenues collected on a fixed versus variable basis. Fixed costs are those that generally do not change with the amount of energy consumed while variable costs generally increase as the amount of energy consumed increases. As a basic ratemaking principle, recovering fixed costs through fixed charges more closely aligns the customer's bill with the customer's cost to serve. The TY 2014 COS analysis shows that Austin Energy needs to better align its fixed cost recovery with its fixed revenue stream, as reflected in Figure 6.1. The figure shows that 64 percent of AE's costs are fixed while only 25 percent of AE's revenue is collected via fixed charges. The remaining fixed costs are recovered through variable charges.

Overreliance on revenues that vary with consumption creates risks for Austin Energy. First, it inserts a wedge between two of the utility's key strategic objectives: promotion of energy conservation and maintenance of financial integrity. Securing the utility's long-term financial health can run in direct conflict with the goal of reducing long-term consumption of energy unless revenue streams are explicitly decoupled from kilowatt-hour sales. Therefore, loading fixed costs into variable rate charges creates an adverse incentive for the utility to promote additional kWh sales to ensure that it will earn sufficient revenues to cover its fixed costs.

Second, the reliance on revenue recovery through variable rate charges can jeopardize the utility's long-term financial stability if kWh sales fail to meet budget expectations. For example, if sales decline due to weather or if residential sales trend lower — as has been the case, recently, in AE's territory — then the utility may be unable to fully recover its fixed costs in the future. This risk will remain an ongoing challenge for AE's long-term financial stability. The proposed rates address fixed cost recovery through gradual measures that slowly improve cost recovery alignment while minimizing customer impacts.

Figure 6.1

Austin Energy's Fiscal Year 2014 Cash In-flows Compared to Test Year 2014 Cash Out-flows



6.3. OVERVIEW OF PROPOSED RATE CHANGES

In order to better align the costs to their recovery, Austin Energy proposes to change certain rate elements, both in base rates and pass-through charges, within the classes. These changes will allow AE to recover its revenue requirements in a manner that provides greater stability while adhering to the principles used in developing the rates. These rate elements include:

- Remove the seasonality of base rate components for demand and energy from all base rates and for all customer classes to better match with underlying fixed costs.
- Retain the residential tier structure, but use a slightly flatter linear pricing structure across the tiers.
- Adjust the boundaries of the non-residential customer classes receiving secondary voltage to produce more homogeneous customer classes.
- Propose a load factor floor for demand customer classes at secondary voltage to help mitigate rate shock from class switching and to reduce the average rate of extremely low load factor customers.
- Increase the Customer Charge by 10 percent for all classes on demand rate schedules to improve fixed cost recovery and align charges closer to COS.
- Introduce seasonality to the Power Supply Adjustment, in place of the existing year around uniform rate, to better align the variability of those costs and send appropriate price signals consistent with the Nodal wholesale market.
- Collect the Regulatory Charge and two components[106] of the Community Benefit Charge on a uniform basis — adjusted for voltage level — in place of the current collection on a class basis to provide greater rate stability from year to year and reflect the approach that is used currently for the PSA.

[106] The charge associated with the Customer Assistance Program is currently set as a uniform charge at $1.72 per 1,000 kWh for residential customers located inside the Austin City limits and $0.65 per 1,000 kWh for non-residential customers.

- Introduce a load shifting voltage level discount rider in place of the current separate Thermal Energy Storage rate schedules to allow for more growth and adoption of new technologies.

- Propose a uniform 20 percent discount to base rates with no discount on pass-through charges for military bases, State of Texas (State) accounts, and Independent School District (ISD) accounts.

- Remove the current rate limit on group religious worship facilities that was designed to be a term-limited transition rate following AE's first rate increase in 18 years.

- Preserve the spirit of the settlement of the appeals to the PUCT in Docket 40627 (Settlement), therefore, retaining the current rate distinctions between inside- and outside-City limit customers.

In addition to making these modifications, the proposed base rate design results in an overall decrease of 1.4 percent in total projected revenue. However, the proposed rate decrease by customer class varies substantially because some customer classes are currently paying significantly more than their COS such as large Secondary and Primary Voltages, whereas other classes — primarily Residential — are paying less than their COS. As a result, AE is applying a gradual step in moving most customers closer toward the COS, but with the adoption of these new rates, the utility still will not be in full alignment with the COS.

The following sections will describe each rate design recommendation in detail.

6.4. CHANGES TO SEASONALITY OF RATES

For all customer classes, current base rates are different during the summer[107] and non-summer[108] months. However, based on the data reviewed during this COS study, Austin Energy concluded that the underlying base rate cost drivers do not vary significantly with the season. This is in part because the base rates recover costs that are primarily fixed in nature and are less influenced by seasonal price volatility.[109] Seasonal base rates have increased AE's financial risk because a large portion of its revenue requirement is designed to be recovered in the four summer months. As a result of the overreliance on the summer month revenue streams, Austin Energy has a financial incentive to increase

[107] Summer: June through September.

[108] Non-Summer: October through May.

[109] The same rationale applies to the selection of 12CP for the Production-Demand allocator: fixed cost recovery over the entire 12 month period reflects more closely the manner in which those costs are incurred as opposed to the 4CP allocator, which would drive recovery into the four summer months.

sales while at the same time encouraging its customers to improve their energy conservation efforts. In essence, the seasonality in AE's base rates directly contradicts clearly stated public policy goals.

Additionally, with the significant differential between the current summer and non-summer rates, it may be a challenge for customers to manage monthly bills. Removing the seasonality from base rates will provide the added benefit to AE's customers of more predictable monthly bills with less volatility. Thus, AE proposes eliminating the summer and non-summer base rate differentials, resulting in flatter and more predictable customer bills.

In conjunction with eliminating the seasonality in base rates, Austin Energy proposes converting the PSA to a seasonally-adjusted rate. Unlike non-power supply fixed costs, the price of power in the ERCOT market is highly volatile and reflects changes in seasonal demands. Section 6.5.1, Changes to Pass-Through Charges addresses this recommendation in greater detail.

6.5. CHANGES TO RESIDENTIAL RATES

Austin Energy proposes modifying residential customers' rate tiers by raising the rate of the first tier and making corresponding reductions in the rates for the top tiers. Moderating, or flattening, the tiered rates ensures greater revenue stability. It may also help ameliorate future erosion of the Residential class' cost recovery if the trends outlined below continue into the foreseeable future.

6.5.1. Factors Impacting Residential Classes Deviation from COS

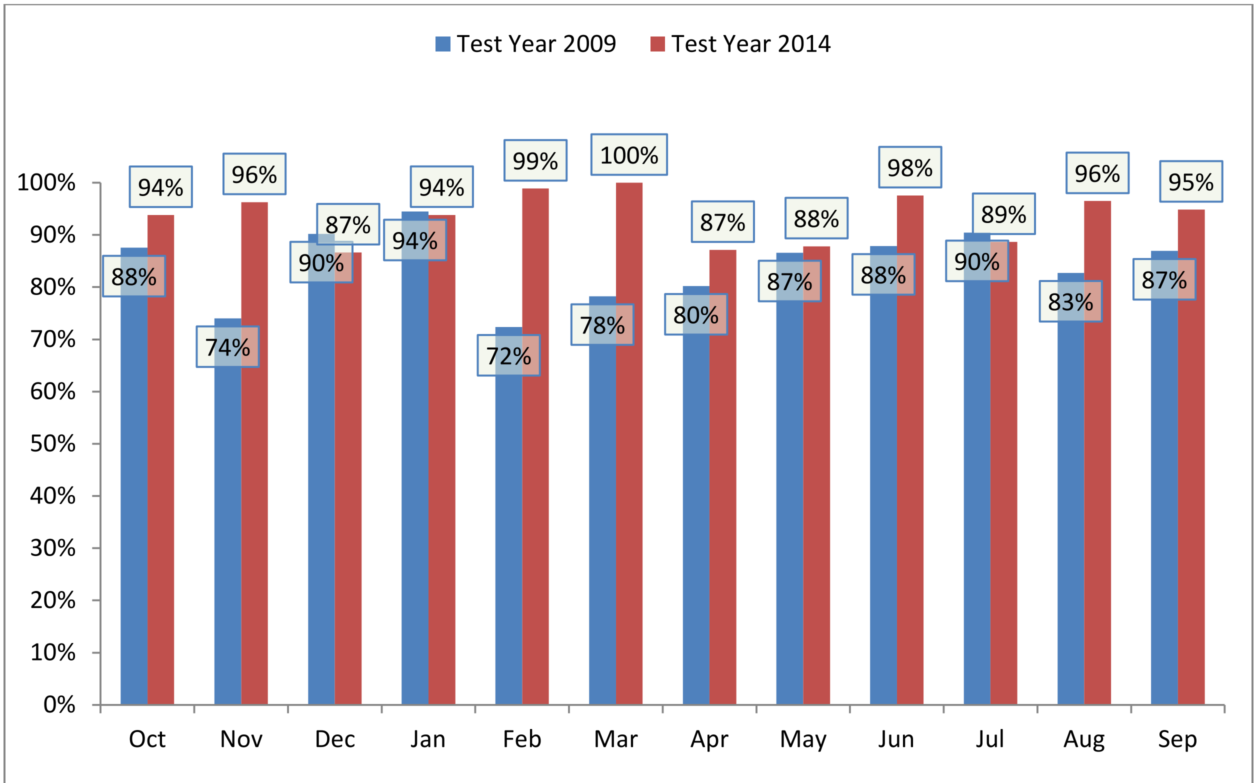
One of the reasons that the residential class remains under-recovered is that the class' load characteristics have changed since the 2012 general rate review. Specifically, customer class demand is closer to the AE system peak than in the previous cost of service study and across the system, the average residential energy consumption appears to be in a sustained decline.[110] This decline is due in part to the success of energy efficiency programs, the five tier inclining rate structure, there has been more new multi-family construction as compared to single family dwellings, and updated building codes with higher emphasis on energy efficiency.

[110] Energy is the amount of electricity consumed over time while demand is the amount of power required at any given moment. So, despite declining energy consumption over the course of a month, Residential customers have air conditioning load that cycles on very close to peak hours during the summer months, exerting instantaneous demand on the system very close to the hours when AE's overall system peak demand is established.

6.5.1.1. Load Characteristics

Different load characteristics can result in different costs to serve, along with different coincidences with system peak loads.[111] For example, with residential peak demand contribution a higher percentage of the AE system peak as compared with the last cost of service study the class receives a larger allocation of system demand-related costs, such as distribution costs. Figure 6.2 compares residential coincidence factors for TY 2009 and TY 2014, the two general rate review periods. The figure shows that residential coincidence factors have increased since the last COS review, resulting in greater allocations of some demand related costs.

Figure 6.2
Residential Coincidence with AE System Peak Factors
Comparing Test Year 2009 to Test Year 2014



Coincidence Factor is the ratio of the class coincident demand (CP) to the class maximum demand

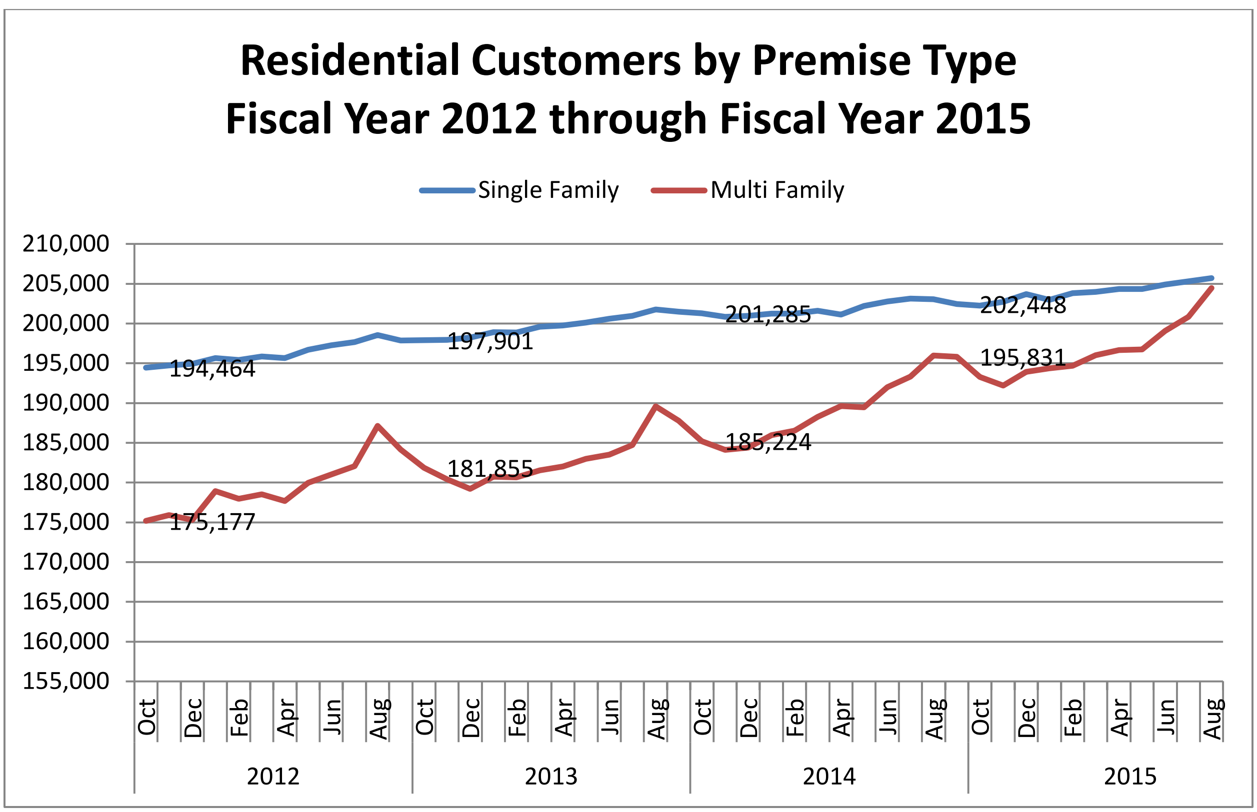
[111] Coincidence with system peak load relates to the amount of a customer's peak load that occurs at the same time as or coincides with the system peak load.

6.5.1.2. Residential Housing Stock

The significant increase in energy efficient single-family and multi-family construction since 2009 is another contributing factor to the shift in costs to the residential class. Today, multi-family dwellings, where square footage per residence tends to be smaller, represent approximately 50 percent of the Austin area housing stock. Figure 6.3 shows that growth in multi-family residential customers since 2012 is approaching three percent per year, whereas growth in single-family residential customers is approximately 0.1 percent per year.

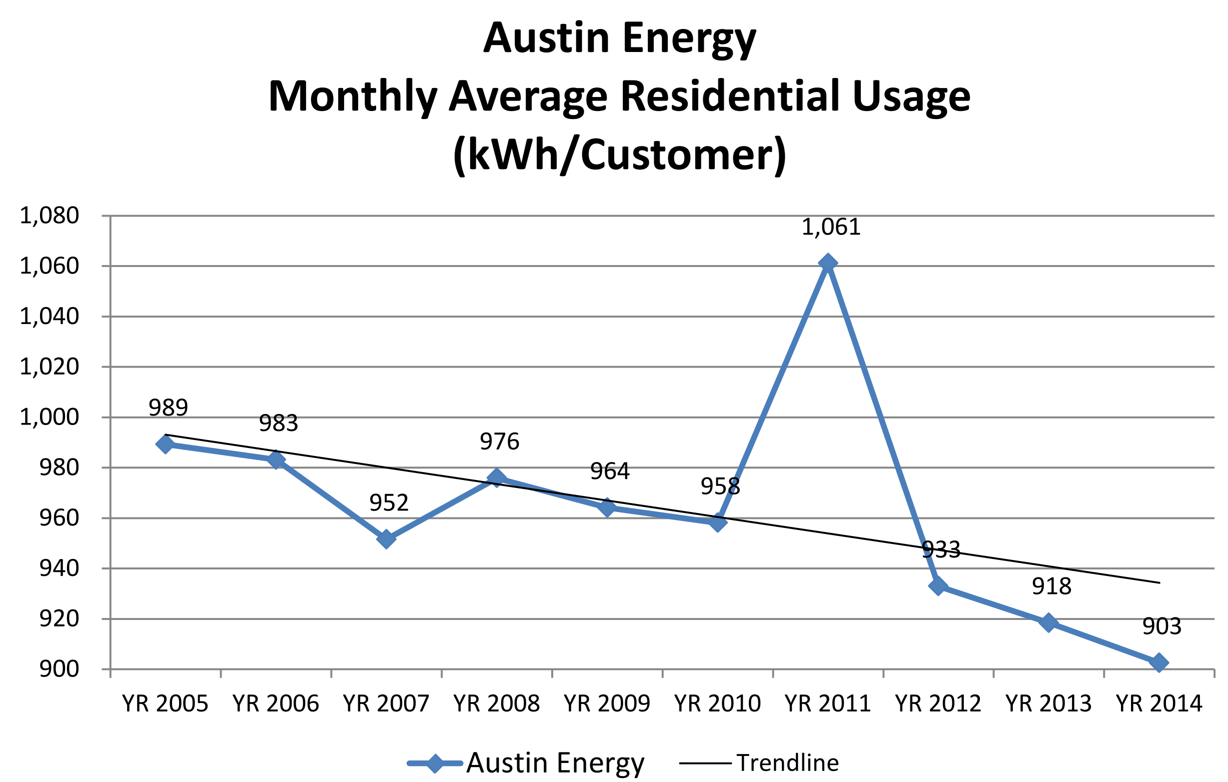
Also, Austin Energy has witnessed annual green building energy code savings that almost tripled from 3,751 megawatt-hours (MWh) to 10,504 MWh between FY 2013 and FY 2014. This, coupled with the adoption of the 2012 International Energy Conservation Code (IECC) in 2013, has driven reductions in energy consumption in new construction. Austin Energy estimates that the IECC could result in a 14 to 16 percent improvement in efficiency over the 2009 Austin Code and a reduction in peak demand. This trend is expected to continue as the City works toward adoption of the 2015 Net Zero Energy Capable residential building codes.

Figure 6.3



Thus, although the number of residential customers increased 8.08 percent from 2009 to 2014, during that same timeframe, the average AE residential monthly consumption decreased from 964 kWh to 903 kWh, a 6.33 percent decrease.[112] The downtrend trend is representative of a shift that has been ongoing for more than a decade and has important implications for certain aspects of the COS analysis and for rate design. Figure 6.4 shows the monthly average residential usage per customer from calendar year 2005 to 2014. During that interval, consumption declined at a pace around 0.6 percent per year through 2009, followed by an even greater annual decline of 1.2 percent per year after 2009, despite the anomalous results in 2011 due to extreme weather.[113]

Figure 6.4



Source: EIA Form 861 Data

[112] Based on Energy Information Administration (EIA) 861 data. EIA data is based on a calendar year, versus Austin Energy data, which is based on a fiscal year. Using EIA data allows comparison to other utilities on a consistent basis.

[113] According to National Climatic Data Center's database, calendar year 2011 was an abnormal year, in which City of Austin broke every major heat record, including most triple-digit Fahrenheit degree days, hottest month in recorded history, and hottest day in history.

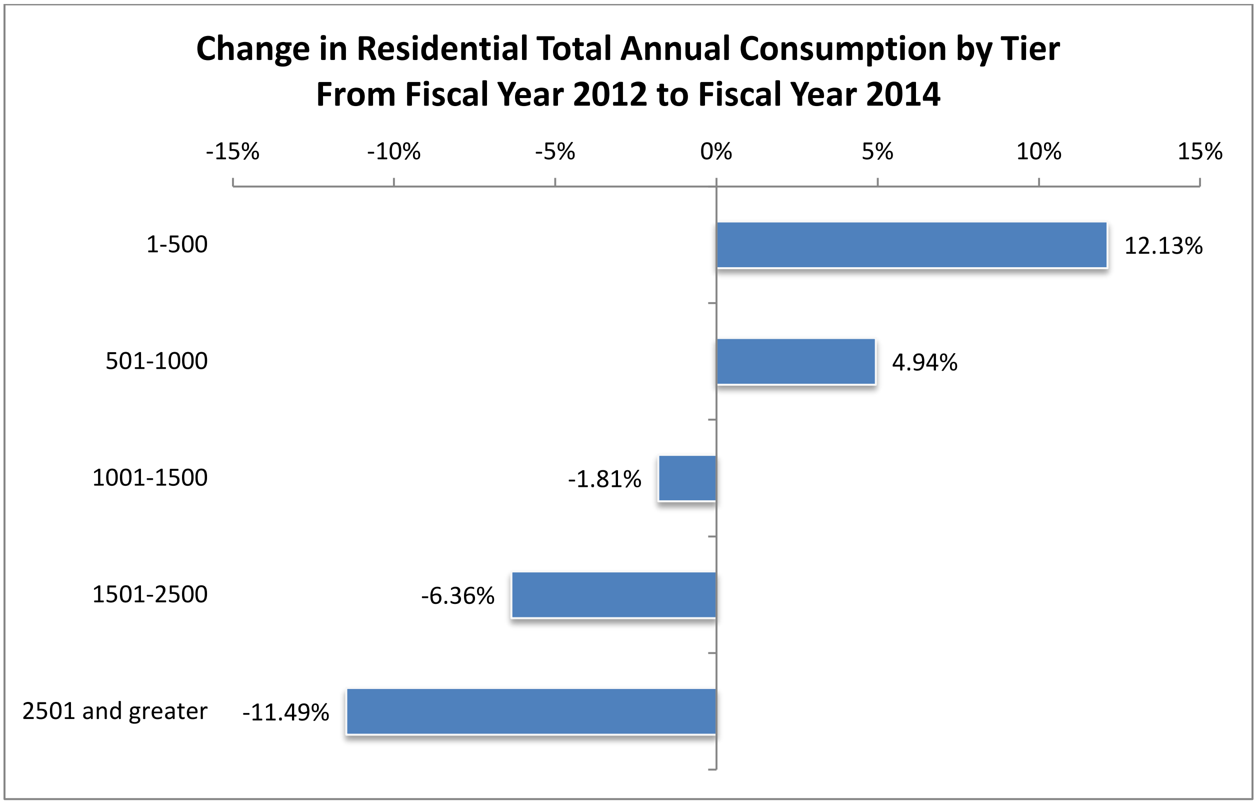
6.5.1.3. Declining Average Consumption

During the 2012 rate review, Austin Energy established energy consumption tiers for the residential customer class. Customers inside the City limits have a five tiered rate structure, while customers outside the City limits effectively have a three tiered rate structure. The current tiered rate structures for energy use on a monthly basis are:

Inside the City Limits	Outside the City Limits
0 – 500 kWh	0 – 500 kWh
501 – 1,000 kWh	501 – 1,000 kWh
1,001 – 1,500 kWh	1,001 kWh and Over
1,501 – 2,500 kWh	
2,501 kWh and Over	

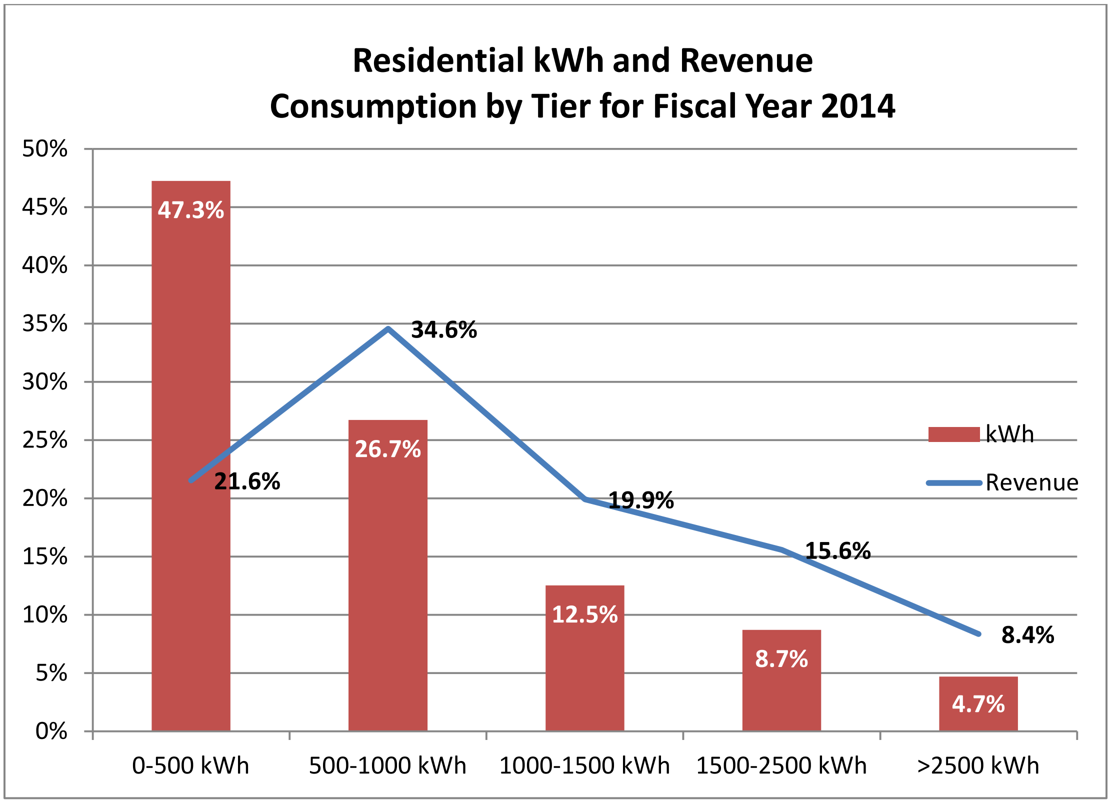
The current inclining tiered rate structure, which provides a strong pricing signal to larger consumers of electricity to conserve electricity, also is driving the changes in consumption. Since 2012, consumption in the fourth and fifth tiers has decreased by 17.9 percent combined, as shown in Figure 6.5, while consumption in the first two tiers increased significantly. This has exacerbated AE's challenge to recover its residential class fixed costs.

Figure 6.5



Compounding the issue, AE's residential tiers were designed with the first tier set below the COS by 63.1 percent while the fourth and fifth tiers were set above the COS at 48.6 percent and 63.6 percent, respectively. These higher rates paid by large consumers improve the economic incentives to invest in home energy efficiency improvements and on-site generation for high-usage consumers. Figure 6.6 shows the residential customer class' total energy consumption by tier and its corresponding total energy charge revenue collected for FY 2014. While 47.3 percent of consumption occurs in the first tier, only 21.6 percent of revenues are collected from the first tier usage. Fourth and fifth tiers represent 13.4 percent of usage, while revenue from these top two tiers is 24 percent of total tier revenues.

Figure 6.6

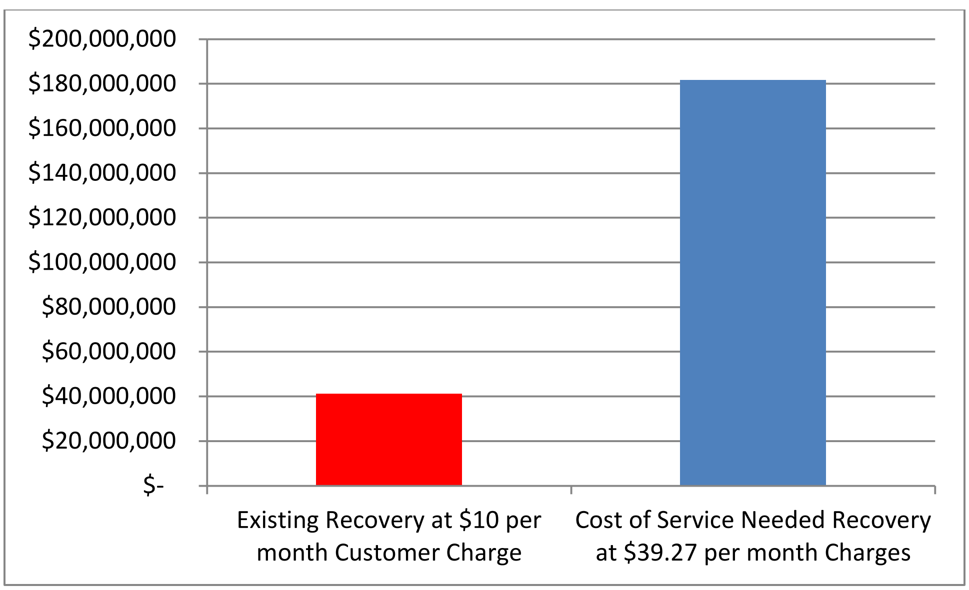


Based on these trends, in order to fully recover its fixed costs, significant usage in the upper tiers must occur to offset the under-collections in the first tier. Figures 6.5 and 6.6 show that AE is instead experiencing significant decreases within the upper tiers, while growth in the lower tiers continues at rates below AE's costs. While base rates principally recover fixed costs, AE recovers the majority of its fixed costs from residential customers via the energy charge, rather than the customer charge, which is a flat monthly charge. Recovering fixed costs from a variable rate component puts AE's financial stability at risk.

Ultimately, AE anticipates that under-recovery in the lower rate tiers will remain a growing concern because these tiers are priced below the COS and a significant portion of residential customers' consumption occurs here. As a result, AE is not recovering its fixed costs from many residential customers, let alone its overall class revenue requirement, which inevitably increases the financial risk to the utility. Moreover, when there is particularly low residential energy usage, as was the case in summer 2007 when temperatures were unusually moderate, AE could significantly under-collect base revenues.

During the 2012 rate review, the residential fixed Customer Charge and Electric Delivery (or wires) Charge, were set at $10.00 per month and $0.00 per month, respectively (*i.e.,* there is no Residential Electric Delivery Charge). Generally, these charges should reflect the minimum amount of equipment and service needed for customers to access the electric grid, since these costs vary with the addition or subtraction of customers and do not vary with energy usage. Austin Energy's Residential customer class has grown by 8.08 percent since 2009. The fixed customer-related costs have grown at a similar rate, but only 12.5 percent of these customer-related costs are being recovered in the fixed monthly Customer Charge. The remaining portion of customer-related costs is recovered in the variable energy charge within the tiered rate structure, where customer consumption is decreasing each year. For TY 2014 the COS analysis shows AE's total residential fixed costs are $39.27 per customer per month, of which, $21.68 is customer costs and $17.59 is electric delivery costs. The current $10.00 per month Customer Charge and $0.00 per month Electric Delivery Charge only recovers about a quarter of what is identified in the COS analysis. This distinction is demonstrated clearly in Figure 6.7.

Figure 6.7
Residential Fixed Customer-related Costs

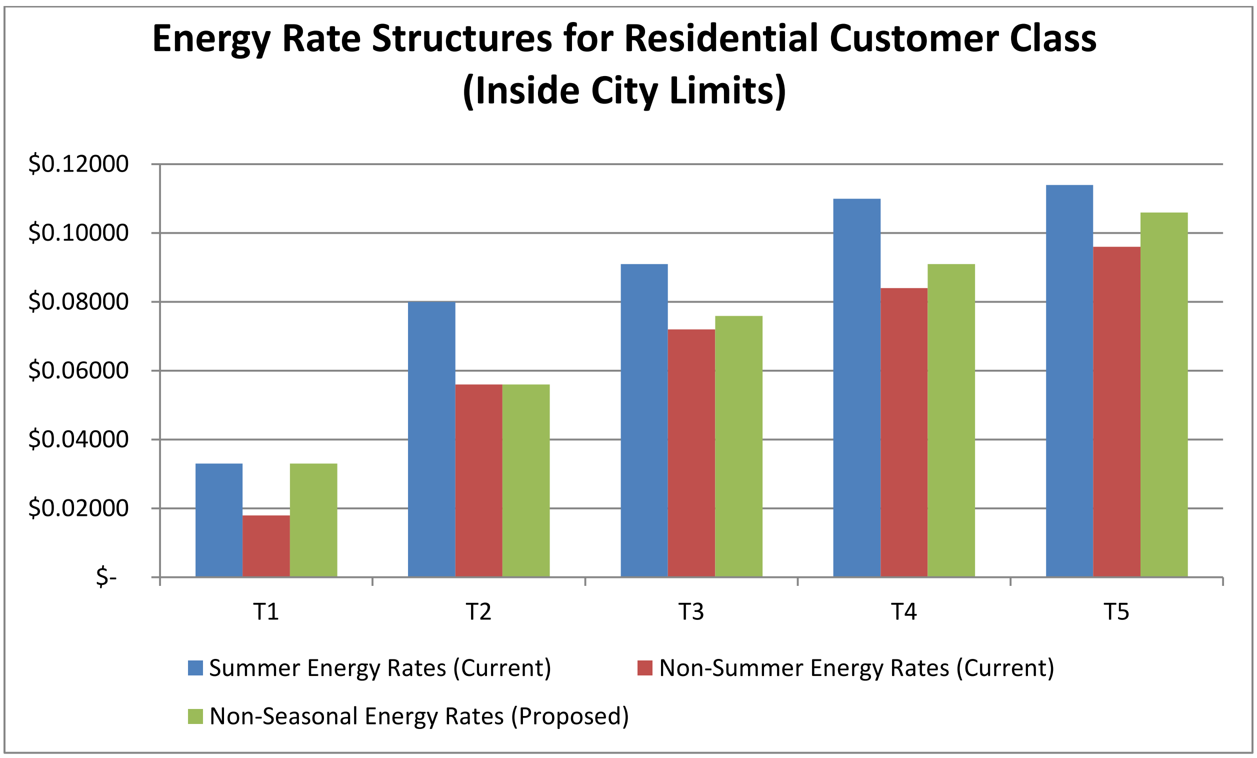


6.5.2. <u>Proposed Residential Rates and Bill Impacts</u>

After reviewing the results of the COS study, Austin Energy recommends taking a gradual approach to correct some of the systemic concerns within the Residential customer class rate design. While it is important to address ultimately the customer-related and wires costs issues, AE believes removing seasonality and flattening the tiered pricing structure are the correct first steps to take as these steps will help avoid compounding the class under-recovery as new residential customers are added to the system.

The current inclining tiered structure is consistent with AE's rate design principles. For inside- or outside-City limit customers, AE proposes maintaining the number of tiers and the cut-off points of the tiers. However, Austin Energy proposes adjusting the energy rates for each tier to a flatter linear pricing structure, combined with removing the seasonality from the base rates. The adjustments to the energy rates will improve revenue stability for AE while continuing to send appropriate conservation signals. Figure 6.8 shows current summer and non-summer rates, as well as proposed non-seasonal rates.

Figure 6.8



The proposed rate design flattens or reduces the price differential between tiers for the class. This change improves the revenue stability of the utility as more revenue is collected in the first two tiers. Also, the proposed rates no longer vary by season, so base revenue is more uniformly collected throughout the year.[114] Figure 6.9 summarizes the recommended residential rates for inside the City limits and Figure 6.10 summarizes those for outside the City limits. Comprehensive comparisons of existing rates, cost of service rates, and proposed rates for each rate schedule are in Schedule H and associated work papers of Appendix G.

Figure 6.9
Residential Base Rates for Inside the City Limits Customers

	Existing Rate	Proposed Rate
Basic Charges ($/month)		
Customer Charge	10.00	10.00
Delivery Charge	0.00	0.00
Summer Tier Rates ($/kWh)		
First Tier (0 – 500 kWh)	0.03300	0.03300
Second Tier (501 – 1,000 kWh)	0.08000	0.05600
Third Tier (1,001 – 1,500 kWh)	0.09100	0.07595
Fourth Tier (1,501 – 2,500 kWh)	0.11000	0.09100
Fifth Tier (2,501 kWh and over)	0.11400	0.10595
Non-Summer Tier Rates ($/kWh)		
First Tier (0 – 500)	0.01800	0.03300
Second Tier (501 – 1,000)	0.05600	0.05600
Third Tier (1,001 – 1,500)	0.07200	0.07595
Fourth Tier (1,501 – 2,500)	0.08400	0.09100
Fifth Tier (2,501 and over)	0.09600	0.10595

[114] AE is proposing the removal of base rate seasonality while at the same time recommending the addition of seasonality to the PSA rates. See Section 6.5.1.

Figure 6.10
Residential Base Rates for Outside the City Limits Customers

	Existing Rates	Proposed Rates
Basic Charges ($/month)		
Customer Charge	10.00	10.00
Delivery Charge	0.00	0.00
Summer Tier Rates ($/kWh)		
First Tier (0 – 500 kWh)	0.03750	0.03800
Second Tier (501 – 1,000 kWh)	0.08000	0.05600
Third Tier (1,001 kWh and over)	0.09325	0.07815
Non-Summer Tier Rates ($/kWh)		
First Tier (0 – 500 kWh)	0.01800	0.03800
Second Tier (501 – 1,000 kWh)	0.05600	0.05600
Third Tier (1,001 kWh and over)	0.07170	0.07815

Under the proposed rates, the first tier rate for customers inside the City limits is equal to the summer first tier rate under current rates. Similarly, the proposed second tier rate is equal to the current non-summer second tier rate. This provides rate stability while at the same time addressing the need for additional revenue from the first tier. Overall, Austin Energy projects that the adjustments to the first and second tier rates will generate an additional $6.7 million per year.

Correspondingly, to avoid creating a rate increase for the class, Austin Energy proposes adjusting the rates for tiers three, four, and five to generate approximately $6.7 million less per year as compared with current rates. The proposed energy charges for the Residential customer class steadily increase from the first to the fifth tier, but the magnitude of the increases between each tier is less than under the current rates. The proposed third tier rate is set such that the overall revenue target for the class is achieved.

The proposed fourth tier rate for customers inside the City limits is set equal to the midpoint between the proposed third and fifth tier rates. The proposed fifth tier rate for customers inside the City limits is set to $0.03 per kWh more than the proposed third tier rate. This differential is based on a high-level analysis of the approximate long-run marginal cost of adding a gas-fired combustion turbine to the generation portfolio. Energy use in the fifth tier (greater than 2,500 kWh per month) is the marginal consumption that could cause AE to need to add a gas-fired combustion turbine to remain properly hedged and thus, it is logical to send a pricing signal for energy use in the fifth tier, above that which is charged in the third tier and reflective of more moderate use, that is consistent with the estimated fixed costs of such an incremental generation investment.

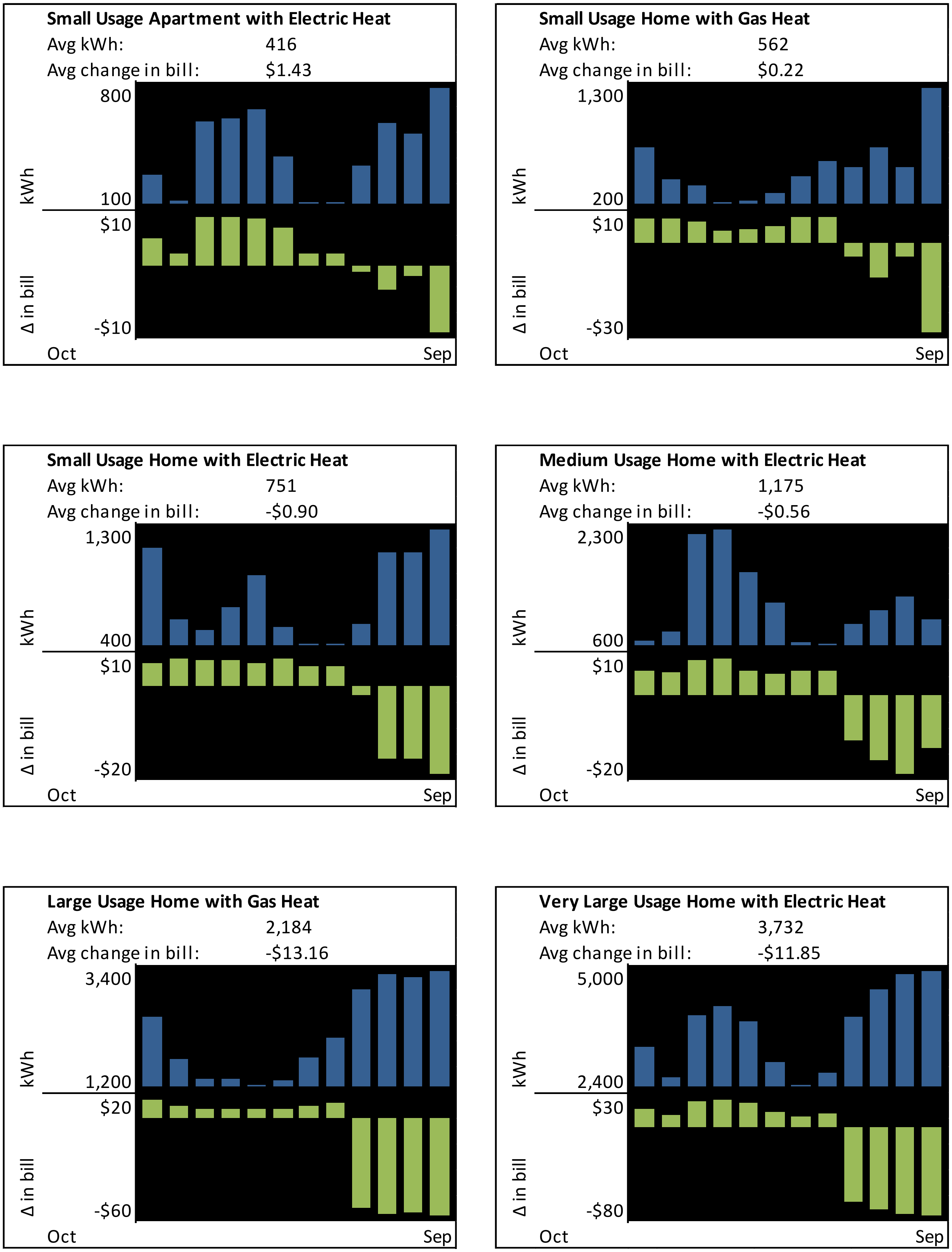
Further, Austin Energy designed the proposed rates for customers outside the City limits to approximate the current differentials between inside and outside City limits rates as well as the overall revenue generation differential implied in the settlement in PUCT Docket No. 40627. Customers participating in CAP will continue to receive the discounts reflected under current rates as discussed further in Section 6.6.1.

To demonstrate bill impacts of the proposed changes to residential rates, AE selected a set of actual customers to obtain realistic representation of the various load characteristics and variety of housing stock, such as small apartments, and small-, medium-, large-, and very-large-homes with either gas or electric heating within AE's service territory.

Figure 6.11 shows a wide range real customer bill impacts based on heating source, amount of energy consumption, and type of housing stock. For TY 2014, Figure 6.11 shows six different types of representative residential customers. For each customer, the figure shows a total bundled rate,[115] a summary of the average monthly energy consumption and change in bills, energy consumption by month (top in blue bars), and change in bills by month (bottom in green bars).

[115] Total bundled rate reflects proposed changes to base rates and structural changes to pass-through charges.

Figure 6.11


Small Usage Apartment with Electric Heat
Avg kWh: 416
Avg change in bill: $1.43
800
100
$10
-$10
kWh
Δ in bill
Oct
Sep
Small Usage Home with Gas Heat
Avg kWh: 562
Avg change in bill: $0.22
1,300
200
$10
-$30
kWh
Δ in bill
Oct
Sep
Small Usage Home with Electric Heat
Avg kWh: 751
Avg change in bill: -$0.90
1,300
400
$10
-$20
kWh
Δ in bill
Oct
Sep
Medium Usage Home with Electric Heat
Avg kWh: 1,175
Avg change in bill: -$0.56
2,300
600
$10
-$20
kWh
Δ in bill
Oct
Sep
Large Usage Home with Gas Heat
Avg kWh: 2,184
Avg change in bill: -$13.16
3,400
1,200
$20
-$60
kWh
Δ in bill
Oct
Sep
Very Large Usage Home with Electric Heat
Avg kWh: 3,732
Avg change in bill: -$11.85
5,000
2,400
$30
-$80
kWh
Δ in bill
Oct
Sep

In each instance, Figure 6.11 shows that monthly bills will decrease in the four summer months and increase in the eight non-summer months. The total change in the average monthly bill depends upon the monthly kWh of each customer. The apartment customer, for example, with electric heat averaging 416 kWh per month will see an increase on average of $1.55 monthly, while customer with large homes (and consumption in the fifth tier) will see monthly decreases of $10 or more per month.

Figure 6.12 shows a generic annual average change in monthly bills under proposed rates compared to existing rates. Percentages for CAP accounts are larger due to the amount being divided by a smaller overall bill. Additional comprehensive comparisons of bill impacts by usage level and season for each rate schedule are in Schedule H and associated work papers of Appendix G.

Figure 6.12

	Annual Average Change in Monthly Bill Under Proposed Rates vs. Current Rates						
No.	Customer Class by Usage	Bill Frequency	Cum. Bill Frequency	Inside $	Inside %	Outside $	Outside %
		(A)	(B)	(C)	(D)	(E)	(F)
1	**Residential**						
2	0 and Below (kWh)	0	0.0%	$ -	0.0%	$ -	0.0%
3	1 - 250 (kWh)	390,124	8.7%	$ 0.93	4.8%	$ 1.31	6.8%
4	251 - 500 (kWh)	908,516	28.9%	$ 2.80	7.4%	$ 3.92	10.4%
5	501 - 750 (kWh)	869,872	48.3%	$ 2.42	3.9%	$ 3.84	6.3%
6	751 - 1000 (kWh)	647,320	62.7%	$ (0.22)	-0.2%	$ 1.08	1.2%
7	1001 - 1250 (kWh)	487,634	73.5%	$ (2.15)	-1.8%	$ (0.77)	-0.6%
8	1251 - 1500 (kWh)	356,103	81.5%	$ (3.38)	-2.2%	$ (1.72)	-1.1%
9	1501 - 1750 (kWh)	250,444	87.0%	$ (4.52)	-2.4%	$ (2.66)	-1.4%
10	1751 - 2000 (kWh)	173,203	90.9%	$ (5.57)	-2.5%	$ (3.61)	-1.7%
11	2001 - 2500 (kWh)	162,859	94.5%	$ (7.15)	-2.6%	$ (5.03)	-1.9%
12	2501 - 3000 (kWh)	86,963	96.5%	$ (7.84)	-2.2%	$ (6.92)	-2.1%
13	3001 - 3500 (kWh)	53,808	97.7%	$ (7.14)	-1.7%	$ (8.81)	-2.2%
14	3501 - 4000 (kWh)	59,576	99.0%	$ (6.42)	-1.3%	$ (10.71)	-2.3%
15	4001 and Above (kWh)	45,484	100.0%	$ (6.07)	-1.1%	$ (11.65)	-2.4%
16							
17	**Customer Assistance Program**						
18	0 and Below (kWh)	0	0.0%	$ -	0.0%	$ -	0.0%
19	1 - 250 (kWh)	24,053	3.6%	$ 0.84	10.3%	$ 1.18	14.3%
20	251 - 500 (kWh)	61,706	12.9%	$ 2.52	10.3%	$ 3.52	14.3%
21	501 - 750 (kWh)	83,189	25.4%	$ 2.17	4.8%	$ 3.46	7.6%
22	751 - 1000 (kWh)	80,837	37.5%	$ (0.19)	-0.3%	$ 0.97	1.4%
23	1001 - 1250 (kWh)	74,040	48.7%	$ (1.93)	-2.0%	$ (0.69)	-0.7%
24	1251 - 1500 (kWh)	66,003	58.6%	$ (3.04)	-2.4%	$ (1.55)	-1.2%
25	1501 - 1750 (kWh)	56,157	67.0%	$ (4.06)	-2.6%	$ (2.40)	-1.5%
26	1751 - 2000 (kWh)	45,859	73.9%	$ (5.01)	-2.7%	$ (3.25)	-1.8%
27	2001 - 2500 (kWh)	61,630	83.2%	$ (6.42)	-2.7%	$ (4.53)	-2.0%
28	2501 - 3000 (kWh)	39,028	89.0%	$ (7.05)	-2.3%	$ (6.23)	-2.2%
29	3001 - 3500 (kWh)	24,729	92.8%	$ (6.42)	-1.7%	$ (7.93)	-2.3%
30	3501 - 4000 (kWh)	18,008	95.5%	$ (5.78)	-1.3%	$ (9.64)	-2.4%
31	4001 and Above (kWh)	30,200	100.0%	$ (5.47)	-1.2%	$ (10.48)	-2.5%

6.5.3. Other Residential Rate Changes

Austin Energy is proposing to suspend the permanent residential time-of-use (TOU) rate option due to lack of interest[116] and the complexity of the TOU rate design.[117] The current rate is also

[116] For the majority of the residential TOU existence, AE has averaged only two accounts under this rate option.

inconsistent with AE's proposed recommendations concerning the lack of seasonality of base rates. However, residential customers will still have a TOU rate option under AE's pilot TOU option,[118] which is aligned with fixed cost recovery, price signals, and non-seasonality within base rates.

6.6. CHANGES TO NON-RESIDENTIAL RATES

In response to a variety of concerns expressed by members of the non-residential customer classes, Austin Energy is making considerable improvements and changes to these rates, including: (1) adjusting the secondary voltage boundaries, (2) providing a load factor floor, and (3) aligning customer class charges closer to COS. At the same time, AE acknowledges that research beyond a COS analysis is needed to address some of the concerns. Appendix E discusses these broader issues.

6.6.1. Adjustments to Non-Residential Secondary Voltage Customer Classes

Based on analysis of the Secondary Voltage customer classes, Austin Energy proposes adjusting the boundaries of the customer classes receiving secondary voltage service as follows:

- Secondary Voltage Service 1 (S1) — from 0 to less than 10 kW
- Secondary Voltage Service 2 (S2) — from 10 to less than 300 kW
- Secondary Voltage Service 3 (S3) — 300 kW or above

This alignment of classes expands the current S2 class from an upper bound of 50 kW to 300 kW. This decision is supported by usage characteristics of these customers that is more similar than what was demonstrated during the TY 2009 COS study. Additionally, an analysis of coincidence peaks to system peaks and non-coincidence peaks to the 12NCP indicates grouping of secondary voltage customers with demand from 10 kW up to 300 kW is more appropriate than the current class assignment.

In recognition of the challenges faced by non-residential customers whose demand stayed predominately under 10 kW, but who moved to the next rate schedule for the subsequent year because of a single, summer month event during which demand exceeded the class limit, Austin Energy and its rate consultant thoroughly analyzed the demand and energy charges associated with the non-residential customers receiving service at secondary voltage.

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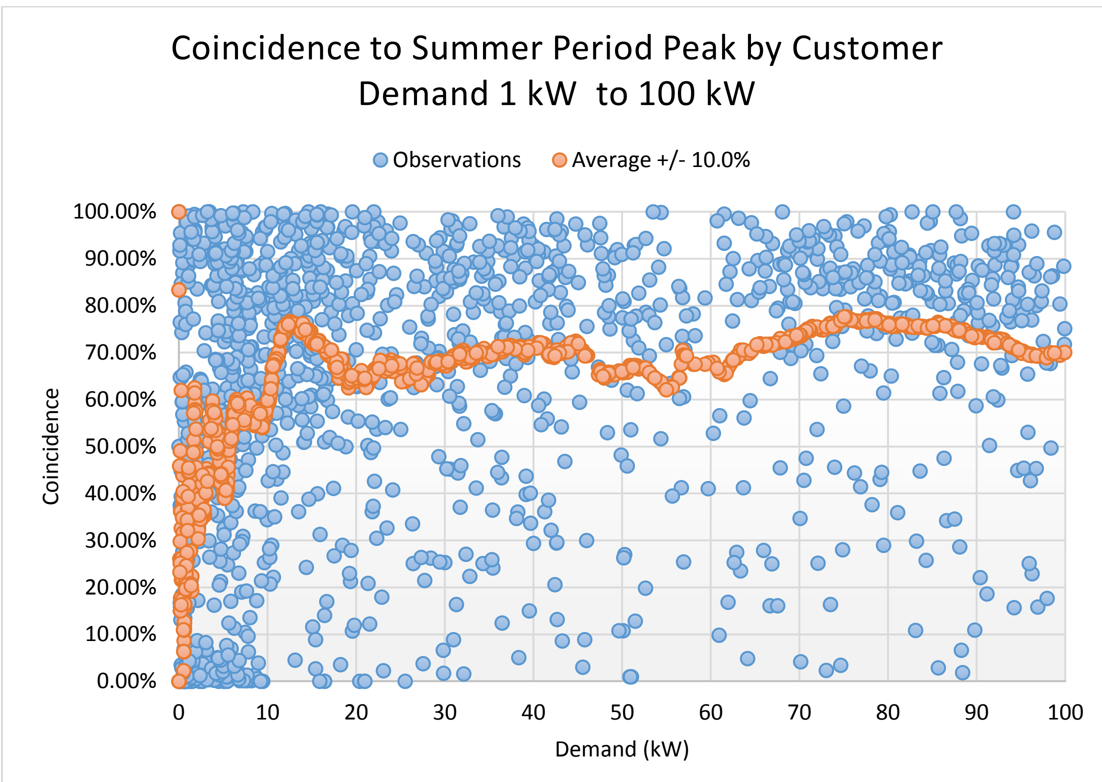
[117] The complexity of the rate is demonstrated by customers not knowing what rates will be charged until after the fact.

[118] The residential TOU pilot was included in AE's tariffs approved by Council in the FY 2016 budget.

While Austin Energy considered adjustments to the upper boundary of the S1 class, the utility ultimately concluded that on the break point analysis, as show in Figure 6.13, an adjustment from 10 kW to 20 kW is not warranted. The analysis shows a large amount of diversity in coincidence factors from 0 kW to 10 kW with an average coincidence factor of 49 percent. After 10 kW, there is a clear spike in coincidence factors to above 60 percent.

These differences within the load characteristics are the main reason for AE's recommendations. Additionally, expanding the existing S1 customer class could increase the coincidence of the class, potentially decrease diversity, and increase the allocated cost responsibility for these customers. Additional analysis is available in NewGen's white paper in Appendix L.

Figure 6.13



Beginning January 2016, AE modified how it annually assigns secondary and primary voltage customers to rate classes. Specifically, AE no longer bases the class definition on a single summer peak, using instead an average of the four monthly summer peaks.[119] Using this average prevents a customer

[119] Approved by Council on September 11, 2015, during the last budget process.

from moving to a different rate class based on a single event that exceeds current class demand thresholds. The TY 2014 COS analysis maintains this policy.

Austin Energy did not adjust the boundaries of the other voltage level customer classes, which remain:

- Primary Voltage Service 1 (P1) — from 0 to less than 3 MW
- Primary Voltage Service 2 (P2) — from 3 to less than 20 MW
- Primary Voltage Service 3 (P3) — 20 MW or above
- Transmission Voltage Service 1 (T1) — greater than 0 MW
- Transmission Voltage Service 2 (T2) — 20 MW or above with at least 85 percent load factor

6.6.2. Secondary Demand Customer Classes Rate Adjustment for Low Load Factor

A secondary customer's demand rate increases sharply as the customer's load factor decreases, as shown in Figure 6.14, and validated by a spring 2015 NewGen study.[120] While this load factor curve supports City Council's goal of encouraging energy efficiency throughout the community, the resulting rate impact could create affordability challenges for low load factor customers.

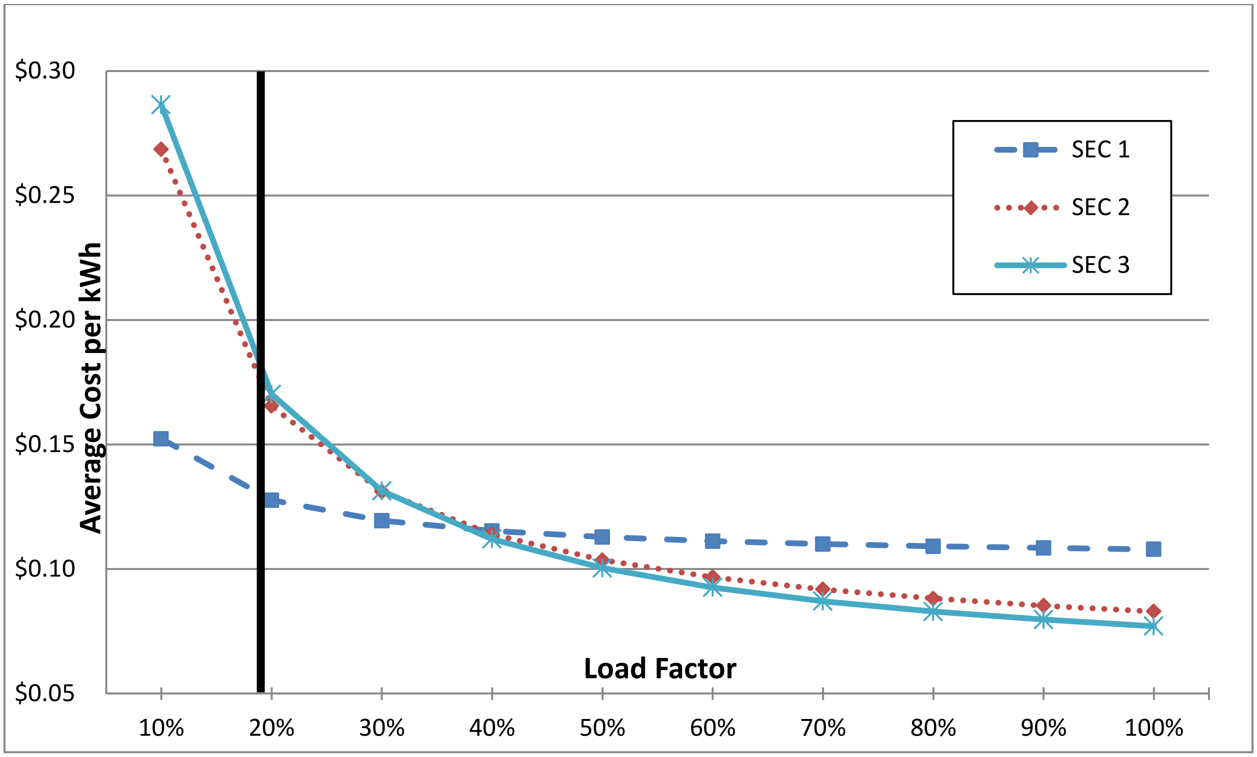
In recognition of these issues, Austin Energy proposes adjusting the rate for certain low load factor customers by setting a floor on the applicable load factor at a load factor of 20 percent. In other words, any commercial customer with a load factor below 20 percent will be billed as if the customer had a 20 percent load factor. This approach will reduce billed demand that the customer would see on their bill to be reflective of load factor of at least 20 percent.

Figure 6.14 shows the steep load factor curve embedded within AE's Secondary Voltage customer classes, while the vertical black line represents AE's recommended implied floor on load factor.

[120] See Appendix C, *Small Commercial Customer Demand Charge Study* for a discussion of rates for commercial customers as a function of load factor.

Figure 6.14

Secondary Voltage Customer Classes Average Cost per Energy at Existing Rates



6.6.3. <u>Increase Customer Charges for Demand Customer Classes</u>

Austin Energy proposes increasing the Customer Charge by 10 percent for all classes receiving a demand charge, with the exception of the T2 customer class. This increase will both align all charges closer to cost of service and improve AE's fixed cost recovery. Figure 6.15 summarizes the current and proposed non-residential customer charges. The increased revenue generated by the increase in the customer charge is offset by a corresponding decrease in the various energy charges for each of these classes. See section 6.4.5 for more detailed discussion of the energy rates.

Figure 6.15
Non-Residential Customer Charges Inside the City Limits

	Existing Rates ($/ month)	Proposed Rates ($/ month)
Customer Charges		
S1[(1)]	18.00	18.00
S2	25.00	27.50
S3	65.00	71.50
P1	250.00	275.00
P2	2,000.00	2,200.00
P3	2,500.00	2,750.00
T1	2,500.00	2,750.00
T2	2,500.00	21,120.00

(1) S1 does not include a demand charge as part of the class rate design.

6.6.4. Modifying Thermal Energy Storage Rate

The current tariff requires AE to design new rate schedules for Thermal Energy Storage (TES) customer classes based on the size of customer's TES system. Creating and maintaining AE's electric tariff[121] and configuring these rates within AE's billing system[122] is an administrative burden for AE. Additionally, the existing process creates an extensive time delay for potential new TES customers if they do not already fit within one of the current TES rate schedules. Also, the current tariff is not well aligned with new technologies like, battery storage.

To resolve these concerns, Austin Energy recommends creating a load shifting voltage level discount rider for customers that can shift a year-round load using storage technologies.[123] This rider would not apply to customers who eliminate or replace their load through the use of alternative fuels. By shifting up to 95 percent of their load from on-peak to off-peak periods, these customers benefit the utility by bringing down the overall system cost through power supply and transmission cost savings, costs which are recovered via pass-through charges, while improving the system load factor.

The new rider rate schedule will adjust the time periods during which the underlying customer class rate schedules demand and energy charges are applied in order to incentivize the appropriate off-

[121] Requiring City Council's approval.

[122] Typically, billing system configurations require from 30- to 90-days based on the complexity of the reconfiguration.

[123] At a minimum the load shifted will need to be 30 percent of the customer's normal on-peak billed demand.

peak period consumption behavior. This new rider will encourage both more growth and the adoption new technologies within the TES sector.

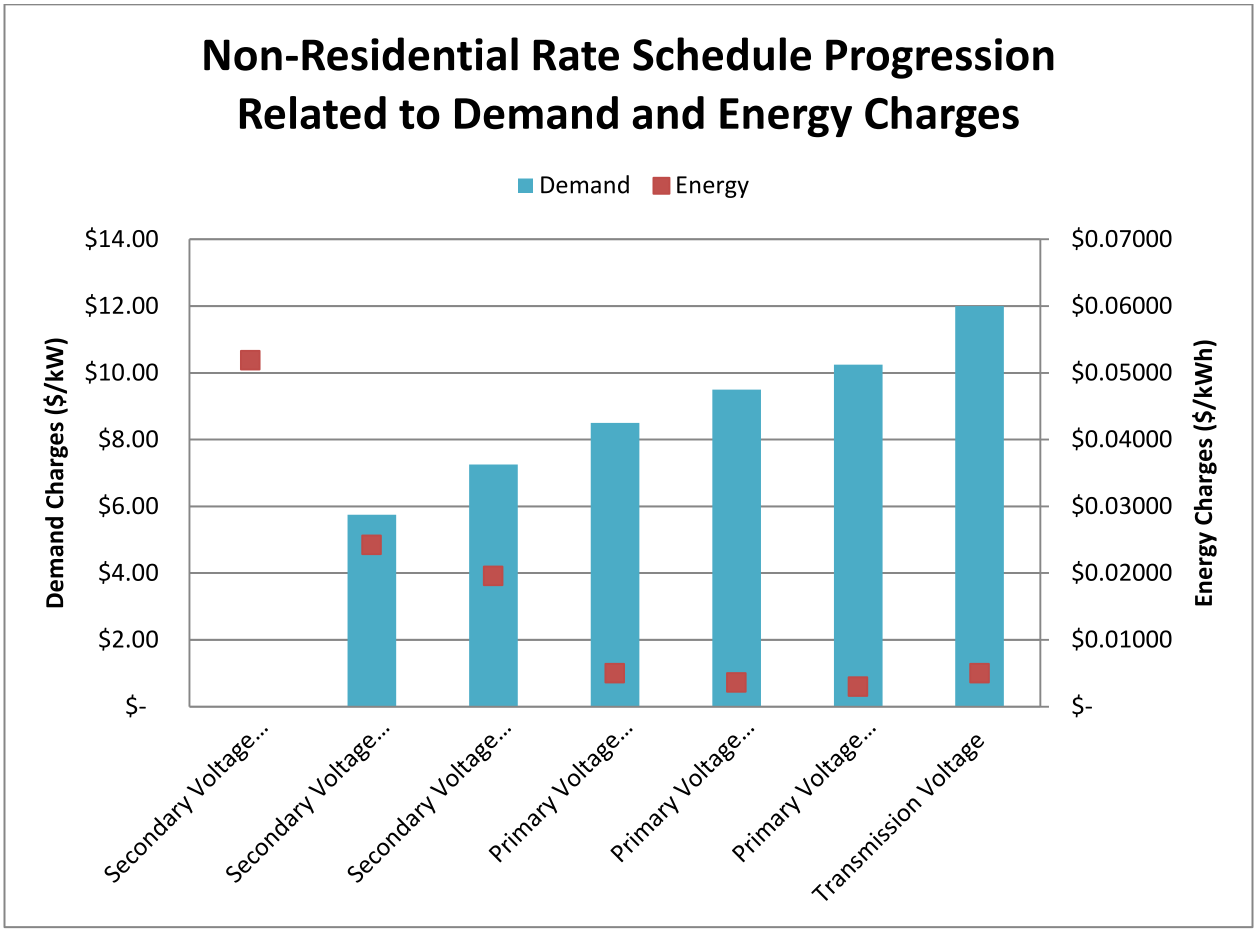
6.6.5. Proposed Non-Residential Rates and Bill Impacts

The proposed non-residential demand and energy base rate charges reflect a sensible, cost-based progression, with demand charges increasing and energy charges decreasing at higher demands and voltage levels, as illustrated in Figure 6.16. Typically, customers with increasing levels of demand and higher voltage service requirements exhibit increasing load factors as well.[124] The costs to serve these types of customers reflect an increasing percentage of capital intensive costs — like high voltage transformers, substations, and distribution lines — and a decreasing percentage of variable, energy-related costs. Therefore, collecting a larger percentage of total revenues through fixed charges, like the demand charge, aligns revenue collection more closely with the manner in which the costs are incurred.

Furthermore, designing rates with a clear progression between rate classes helps minimize rate shock for customers that switch between rate classes. For example, with the new commercial class assignment methodology that places customers in a rate class based on their average 4CP demand instead of the single peak demand may result in more movement for customers between rate classes. If the progression between the P1 and P2 demand charges is logical, then large swings in different types of charges can be avoided, minimizing undesirable bill impacts. The stepped progression also helps Austin Energy's revenue recovery by minimizing the differential between charges in different classes. As a customer moves from one rate class to another, the amount of revenue collected in the rate classes should not significantly change if the rate design progresses logically. The bars in the figure show the progression of demand charges for each customer class, while the dots show the general decline in energy charges with higher consumption customer classes.

[124] Load factor is the ratio between the actual amount of power demanded to the peak demand required by the customer.

Figure 6.16



As with residential customers, Austin Energy proposes removing the seasonality from base rates.[125] Austin Energy also proposes adjusting the energy rates for each non-Residential customer class, except for Secondary Voltage 1, to eliminate the over-recovery demonstrated in the TY 2014 COS study and to account for the proposed increases in customer charges for each of those classes.

These recommendations will better align the rate structures with the COS analysis, while continuing to send appropriate efficiency signals. These changes also improve fixed cost recovery and balance the amount of class revenue requirement at risk.

The non-residential rates for customers inside the City limits are summarized in Figure 6.17 and for customers outside the City limits are summarized in Figure 6.18. Comprehensive comparisons of

[125] AE is proposing the removal of base rate seasonality while at the same time recommending the addition of seasonality to the PSA rates. See Section 6.5.1.

existing rates, cost of service rates, and proposed rates for each rate schedule are in Schedule H and associated work papers of Appendix G.

Figure 6.17
Non-Residential Base Rates for Inside the City Limits Customers

	S1	S2	S3	P1	P2	P3	T1
Basic Charges							
Customer Charge ($/month)	18.00	27.50	71.50	275.00	2,200.00	2,750.00	2,750.00
Delivery Charge ($/kW)	0.00	4.00	4.50	3.50	4.00	4.50	0.00
Demand Rates ($/kW)	0.00	5.75	7.25	8.50	9.50	10.25	12.00
Energy Rates ($/kWh)	0.05190	0.02421	0.01955	0.00500	0.00360	0.00300	0.00500

Figure 6.18
Non-Residential Base Rates for Outside the City Limits Customers

	S1	S2	S3	P1	P2	P3	T1
Basic Charges							
Customer Charge ($/month)	18.00	27.50	71.50	275.00	2,200.00	2,750.00	2,750.00
Delivery Charge ($/kW)	0.00	4.00	4.50	3.50	4.00	4.50	0.00
Demand Rates ($/kW)	0.00	5.75	7.25	8.50	9.50	10.25	12.00
Energy Rates ($/kWh)	0.05190	0.02356	0.01902	0.00487	0.00350	0.00300	0.00500

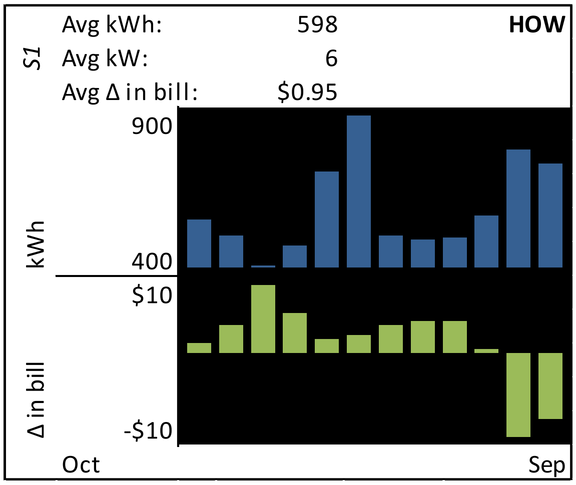
To demonstrate bill impacts, AE again chose to evaluate the impact on real Austin Energy customers, examining bills of a variety of business types, such as offices, utilities, schools, medical, and restaurants. Austin Energy looked at different load factors and voltage levels, and reviewed customers with diverse consumption patterns.[126]

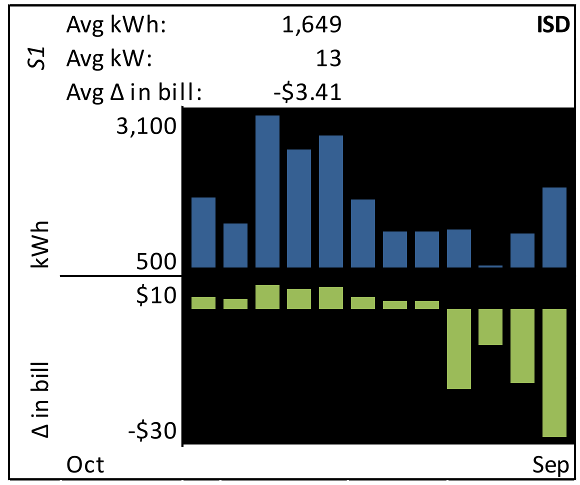
Figure 6.19 shows real customer bill impacts showing a wide range of possible impacts based on different load characteristics. For TY 2014, Figure 6.19 shows 10 different non-residential accounts

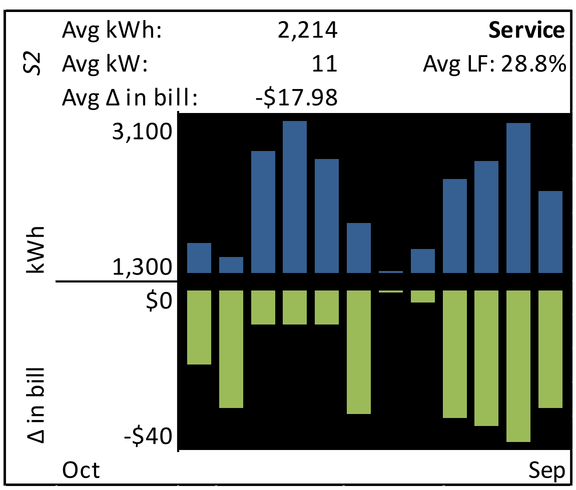
[126] One exception to this process was made for primary voltage customers as these customers are easily identified by their consumption patterns. Therefore, those impact figures are generic customers based on data similar to the class average.

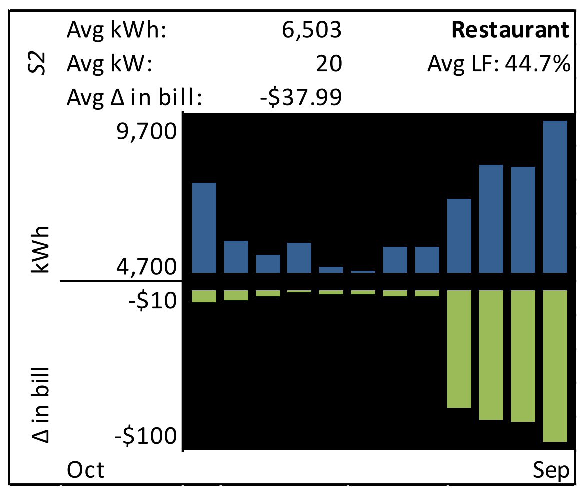
starting with S1 (first row) and moving down to P2 (last row). For each customer, the figure shows a total bundled rate,[127] a summary of the average monthly energy and demand consumption plus change in bills, average load factor, energy consumption by month (top in blue bars), and change in bills by month (bottom in green bars).

Figure 6.19

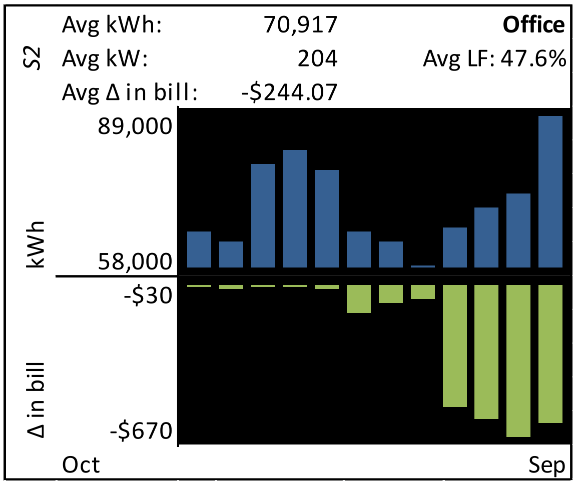


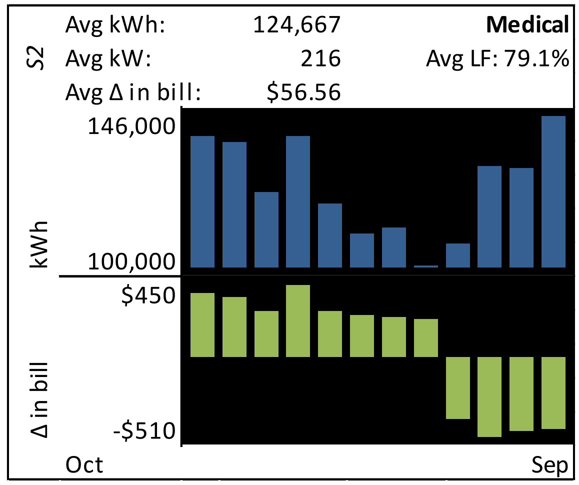


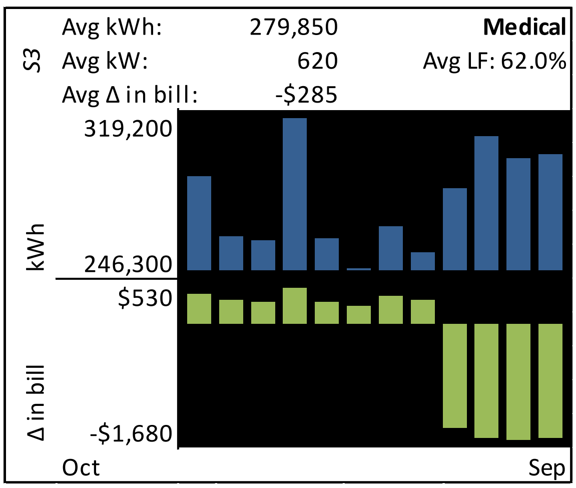


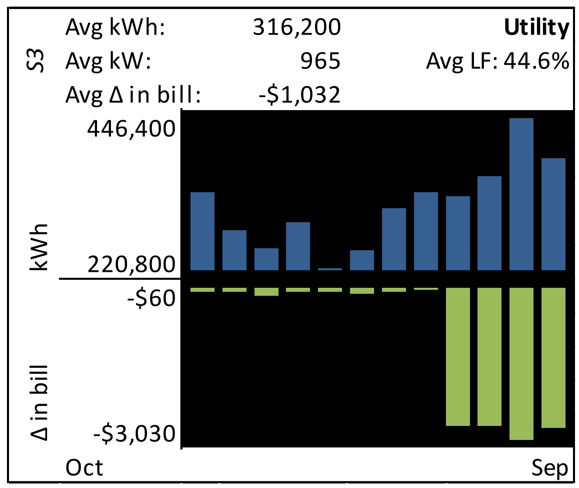


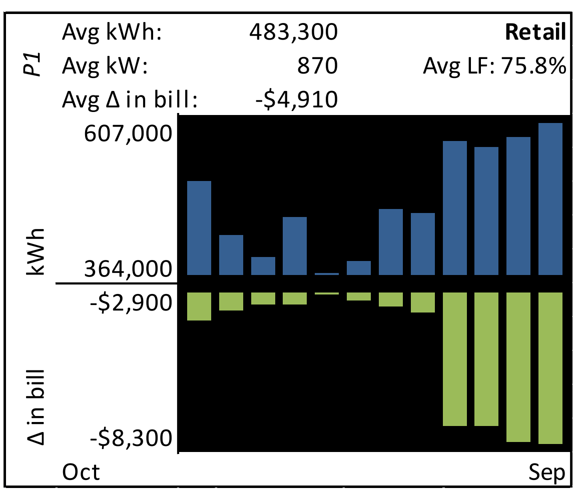
[127] The total bundled rate reflects proposed changes to base rates and structural changes to pass-through charges.


S2
Avg kWh: 70,917
Office
Avg kW: 204
Avg LF: 47.6%
Avg Δ in bill: -$244.07
89,000
kWh
58,000
-$30
Δ in bill
-$670
Oct
Sep


S2
Avg kWh: 124,667
Medical
Avg kW: 216
Avg LF: 79.1%
Avg Δ in bill: $56.56
146,000
kWh
100,000
$450
Δ in bill
-$510
Oct
Sep


S3
Avg kWh: 279,850
Medical
Avg kW: 620
Avg LF: 62.0%
Avg Δ in bill: -$285
319,200
kWh
246,300
$530
Δ in bill
-$1,680
Oct
Sep


S3
Avg kWh: 316,200
Utility
Avg kW: 965
Avg LF: 44.6%
Avg Δ in bill: -$1,032
446,400
kWh
220,800
-$60
Δ in bill
-$3,030
Oct
Sep


P1
Avg kWh: 483,300
Retail
Avg kW: 870
Avg LF: 75.8%
Avg Δ in bill: -$4,910
607,000
kWh
364,000
-$2,900
Δ in bill
-$8,300
Oct
Sep

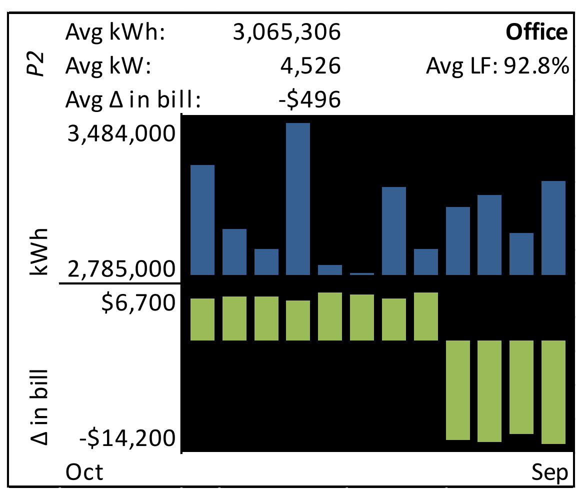

P2
Avg kWh: 3,065,306
Office
Avg kW: 4,526
Avg LF: 92.8%
Avg Δ in bill: -$496
3,484,000
kWh
2,785,000
$6,700
Δ in bill
-$14,200
Oct
Sep

Figure 6.20 shows a generic annual average change in monthly bills under the proposed rates compared to existing rates at different load factors for S1 through P1.[128] Additional comprehensive comparisons of bill impacts by usage level and season for each rate schedule are in Schedule H and associated work papers of Appendix G.

Figure 6.20

Annual Average Change in Monthly Bill Under Proposed Rates vs. Current Rates

No.	Customer Class by Usage	Bill Frequency	Cum. Bill Frequency	Inside		Outside	
				$	%	$	%
		(A)	(B)	(C)	(D)	(E)	(F)
1	**Secondary Voltage (< 10 kW)**						
2	0% LF	36,551	10.4%	$ -	0.0%	$ -	0.0%
3	10% LF	48,480	24.2%	$ (1.32)	-2.4%	$ (1.50)	-2.7%
4	20% LF	42,163	36.1%	$ (2.64)	-2.8%	$ (2.99)	-3.2%
5	30% LF	31,610	45.1%	$ (3.96)	-3.0%	$ (4.49)	-3.5%
6	40% LF	51,077	59.6%	$ (5.28)	-3.1%	$ (5.99)	-3.6%
7	50% LF	43,225	71.9%	$ (6.60)	-3.2%	$ (7.49)	-3.7%
8	60% LF	16,368	76.5%	$ (7.92)	-3.3%	$ (8.99)	-3.7%
9	70% LF	9,886	79.3%	$ (9.25)	-3.3%	$ (10.48)	-3.8%
10	80% LF	10,815	82.4%	$ (10.56)	-3.3%	$ (11.97)	-3.8%
11	90% LF	19,923	88.1%	$ (11.88)	-3.3%	$ (13.48)	-3.8%
12	100% LF	41,973	100.0%	$ (13.20)	-3.4%	$ (14.98)	-3.8%
13							
14	**Secondary Voltage (≥ 10 < 300 kW)**						
15	0% LF	9,738	4.9%	$ 2.50	10.0%	$ 2.50	10.0%
16	10% LF	29,956	20.0%	$ (28.34)	-5.8%	$ (29.15)	-6.0%
17	20% LF	40,134	40.3%	$ (32.55)	-5.4%	$ (35.51)	-5.9%
18	30% LF	39,048	60.0%	$ (36.75)	-5.1%	$ (41.85)	-5.9%
19	40% LF	33,647	77.0%	$ (40.95)	-4.9%	$ (48.20)	-5.9%
20	50% LF	24,561	89.4%	$ (45.15)	-4.8%	$ (54.55)	-5.8%
21	60% LF	12,389	95.7%	$ (49.35)	-4.7%	$ (60.89)	-5.8%
22	70% LF	5,070	98.2%	$ (53.56)	-4.6%	$ (67.24)	-5.8%
23	80% LF	1,794	99.1%	$ (57.76)	-4.5%	$ (73.59)	-5.8%
24	90% LF	534	99.4%	$ (61.96)	-4.4%	$ (79.94)	-5.8%
25	100% LF	1,192	100.0%	$ (66.16)	-4.4%	$ (86.28)	-5.8%
26							
27	**Secondary Voltage (≥ 300 kW)**						
28	0% LF	91	0.8%	$ 6.50	10.0%	$ 6.50	10.0%
29	10% LF	270	3.2%	$ (69.24)	-4.4%	$ (70.47)	-4.5%
30	20% LF	714	9.6%	$ (60.54)	-3.2%	$ (68.27)	-3.7%
31	30% LF	1,289	21.2%	$ (51.85)	-2.4%	$ (66.07)	-3.1%
32	40% LF	1,828	37.6%	$ (43.16)	-1.8%	$ (63.87)	-2.6%
33	50% LF	2,149	56.9%	$ (34.46)	-1.3%	$ (61.67)	-2.3%
34	60% LF	1,908	74.0%	$ (25.77)	-0.8%	$ (59.47)	-2.0%
35	70% LF	1,536	87.8%	$ (17.09)	-0.5%	$ (57.27)	-1.7%
36	80% LF	721	94.2%	$ (8.39)	-0.2%	$ (55.07)	-1.5%
37	90% LF	161	95.7%	$ 0.30	0.0%	$ (52.86)	-1.4%
38	100% LF	482	100.0%	$ 8.99	0.2%	$ (50.66)	-1.2%
39							
40	**Primary Service (< 3 MW)**						
41	0% LF	63	5.2%	$ 25.00	10.0%	$ 39.00	16.5%
42	10% LF	68	10.9%	$ (5,505.07)	-16.7%	$ (4,489.16)	-14.1%
43	20% LF	67	16.4%	$ (5,905.59)	-15.7%	$ (4,937.76)	-13.6%
44	30% LF	80	23.0%	$ (6,306.11)	-14.8%	$ (5,386.37)	-13.1%
45	40% LF	153	35.7%	$ (6,706.64)	-14.2%	$ (5,834.98)	-12.8%
46	50% LF	150	48.1%	$ (7,107.16)	-13.7%	$ (6,283.60)	-12.5%
47	60% LF	152	60.7%	$ (7,507.68)	-13.2%	$ (6,732.20)	-12.2%
48	70% LF	246	81.1%	$ (7,908.21)	-12.8%	$ (7,180.82)	-12.0%
49	80% LF	103	89.6%	$ (8,308.73)	-12.5%	$ (7,629.43)	-11.8%
50	90% LF	21	91.4%	$ (8,709.26)	-12.2%	$ (8,078.05)	-11.7%
51	100% LF	104	100.0%	$ (9,109.78)	-12.0%	$ (8,526.65)	-11.6%

[128] Results for P2 and P3 classes are not presented, as customer-specific proprietary information could be decipherable from this figure.

6.6.6. Other Non-Residential Rate Changes

AE proposes suspending the permanent non-residential TOU rate due to a lack of interest in this rate[129] and the lack of consistency between the current rates and AE's recommendation to remove the seasonality from base rates. However, during the next budget process, AE will propose a new pilot TOU option for non-residential customer classes that aligns with proposed fixed cost recovery, price signals, and non-seasonality within base rates.

6.7. CHANGES TO PASS-THROUGH CHARGES

Austin Energy's approved tariffs include three charges — the PSA, Regulatory Charge, and the CBC[130] — that are passed through directly to customers. While these pass-through charges are adjusted each year in the City's budget process, to conduct a comprehensive COS study, Austin Energy estimated the likely changes in pass-through charges that would then be proposed in the next budget.[131] Over the course of this proceeding, AE will update the estimates as new information becomes available.

While AE is not proposing any changes to the costs[132] recovered through the pass-through charges, Austin Energy recommends changing each charge's structure. The proposed modifications will simplify the management and administration processes as well as improve the rate design. They are also better aligned with AE's rate design principles and provide rate stability from year to year.

The following sub-sections present AE's proposed restructuring of the pass-through charges.

6.7.1. Changes to the Power Supply Adjustment

The Power Supply Adjustment includes revenues from the sale of power to ERCOT,[133] fuel costs,[134] net Purchased Power Agreement costs,[135] power purchased from ERCOT to supply AE's

[129] Currently, AE has 12 non-residential TOU accounts, representing 0.02 percent of all non-residential accounts.

[130] Appendix K provides a detailed description of each pass-through charge.

[131] The impacts found in Figures 6.13 and 6.20 reflect both the proposed changes in base rates, and the anticipated adjustments to the pass-through charges. The specific numbers in the report reflect AE best estimates, at the time of filing this Report to Council, of what those pass-through charges should look like in the upcoming FY 2017 budget process, acknowledging that they are subject to change until then.

[132] Any changes in costs will be considered in the budget process in summer 2016.

[133] Charges and credits from ERCOT, other than the Administrative and Other Fees.

[134] Fuel costs mean fuel, fuel transportation, and hedging gains and losses.

[135] Net Purchased Power Agreement costs are the costs and revenues associated with short- and long-term PPAs, and the costs for distributed generation production.

customer load, and any adjustment for the over- or under-recovery PSA costs balance. The charge is set to recover current year power supply costs, based on the preceding year's expenditures.

The PSA is calculated using the sum of all net power supply costs plus any existing over- or under-recovery PSA costs balance that is attributable to the PSA, divided by the projected service area sales during the historical twelve month period following the effective date of the PSA. This results in an annual uniform system rate per kWh, which is then adjusted for voltage level, and applied to each customer class. Because this charge is driven in large part by fuel prices, the underlying cost drivers of the PSA vary with the season. Thus, Austin Energy proposes introducing seasonality into the PSA, a shift which will improve the timely recovery of power supply costs and help maintain pricing incentives consistent with the City Council's goals for energy efficiency and conservation.

Like most of Texas, Austin Energy has a summer peaking load, meaning that on a system-wide basis, the most electricity is consumed during the summer. As demand goes up, the power supply is constrained, which then can trigger price increases within ERCOT's competitive wholesale power market. Figure 6.21 is a graphic display, known as a "heat map", of AE's hourly ERCOT 4-year average wholesale market nodal settlement prices. This figure shows the volatility and seasonality of power costs within ERCOT on an hourly (y-axis) and monthly basis (x-axis). The map's color coding graphically displays the range of wholesale market settlement prices with color-coded prices escalating from blue, green, yellow, orange, and red. In general, the highest average prices (shaded in pink and red) occur during summer afternoons.

Figure 6.21

Austin Energy's Hourly ERCOT 4-Yr Average Wholesale Market Nodal Settlement Prices ($/kWh)

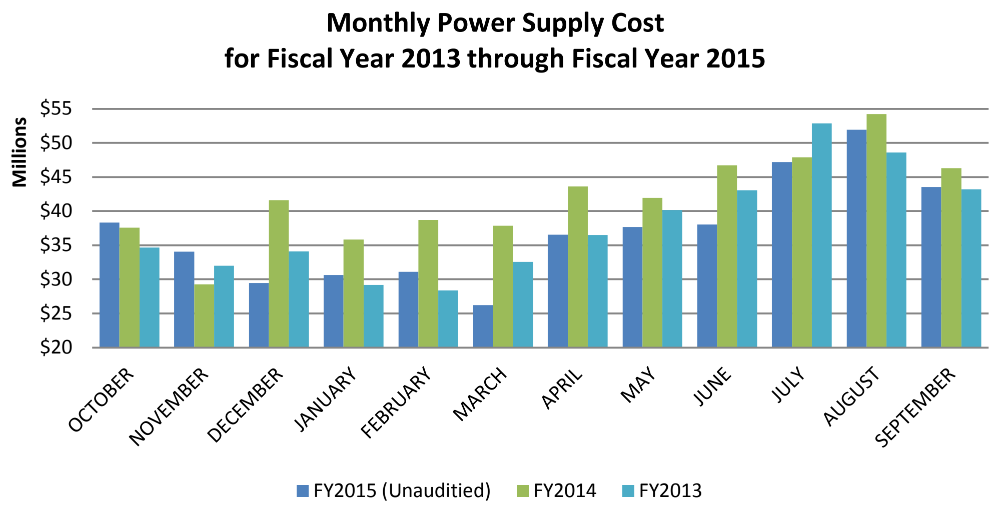
Hours	*Jan*	*Feb*	*Mar*	*Apr*	*May*	*Jun*	*Jul*	*Aug*	*Sep*	*Oct*	*Nov*	*Dec*	*Average*
1	$ 0.026	$ 0.025	$ 0.028	$ 0.030	$ 0.028	$ 0.033	$ 0.030	$ 0.031	$ 0.032	$ 0.030	$ 0.027	$ 0.031	$ 0.029
2	$ 0.025	$ 0.024	$ 0.025	$ 0.028	$ 0.025	$ 0.028	$ 0.028	$ 0.029	$ 0.028	$ 0.027	$ 0.025	$ 0.028	$ 0.026
3	$ 0.024	$ 0.023	$ 0.024	$ 0.025	$ 0.024	$ 0.025	$ 0.027	$ 0.027	$ 0.026	$ 0.024	$ 0.024	$ 0.026	$ 0.025
4	$ 0.025	$ 0.027	$ 0.024	$ 0.025	$ 0.023	$ 0.024	$ 0.026	$ 0.026	$ 0.025	$ 0.024	$ 0.025	$ 0.026	$ 0.025
5	$ 0.032	$ 0.030	$ 0.026	$ 0.026	$ 0.024	$ 0.024	$ 0.026	$ 0.026	$ 0.026	$ 0.025	$ 0.026	$ 0.027	$ 0.026
6	$ 0.034	$ 0.057	$ 0.031	$ 0.028	$ 0.028	$ 0.025	$ 0.026	$ 0.027	$ 0.028	$ 0.028	$ 0.031	$ 0.031	$ 0.031
7	$ 0.108	$ 0.076	$ 0.058	$ 0.052	$ 0.031	$ 0.026	$ 0.027	$ 0.028	$ 0.030	$ 0.037	$ 0.037	$ 0.041	$ 0.046
8	$ 0.062	$ 0.060	$ 0.046	$ 0.033	$ 0.028	$ 0.027	$ 0.028	$ 0.028	$ 0.029	$ 0.033	$ 0.034	$ 0.034	$ 0.037
9	$ 0.044	$ 0.059	$ 0.040	$ 0.036	$ 0.029	$ 0.030	$ 0.033	$ 0.031	$ 0.031	$ 0.031	$ 0.036	$ 0.039	$ 0.036
10	$ 0.044	$ 0.055	$ 0.042	$ 0.038	$ 0.031	$ 0.031	$ 0.035	$ 0.034	$ 0.033	$ 0.038	$ 0.036	$ 0.040	$ 0.038
11	$ 0.044	$ 0.063	$ 0.042	$ 0.037	$ 0.033	$ 0.034	$ 0.042	$ 0.039	$ 0.035	$ 0.034	$ 0.037	$ 0.036	$ 0.040
12	$ 0.035	$ 0.051	$ 0.039	$ 0.039	$ 0.034	$ 0.038	$ 0.047	$ 0.045	$ 0.043	$ 0.038	$ 0.036	$ 0.033	$ 0.040
13	$ 0.032	$ 0.038	$ 0.039	$ 0.040	$ 0.040	$ 0.045	$ 0.049	$ 0.055	$ 0.043	$ 0.038	$ 0.037	$ 0.032	$ 0.041
14	$ 0.030	$ 0.034	$ 0.038	$ 0.042	$ 0.042	$ 0.055	$ 0.051	$ 0.084	$ 0.051	$ 0.040	$ 0.035	$ 0.031	$ 0.045
15	$ 0.029	$ 0.031	$ 0.042	$ 0.044	$ 0.050	$ 0.082	$ 0.067	$ 0.188	$ 0.062	$ 0.052	$ 0.035	$ 0.030	$ 0.059
16	$ 0.029	$ 0.030	$ 0.043	$ 0.059	$ 0.060	$ 0.102	$ 0.071	$ 0.251	$ 0.083	$ 0.068	$ 0.034	$ 0.030	$ 0.072
17	$ 0.029	$ 0.031	$ 0.083	$ 0.066	$ 0.066	$ 0.080	$ 0.084	$ 0.262	$ 0.102	$ 0.071	$ 0.034	$ 0.030	$ 0.078
18	$ 0.040	$ 0.035	$ 0.052	$ 0.049	$ 0.049	$ 0.054	$ 0.064	$ 0.106	$ 0.052	$ 0.044	$ 0.079	$ 0.058	$ 0.057
19	$ 0.050	$ 0.060	$ 0.074	$ 0.041	$ 0.040	$ 0.047	$ 0.049	$ 0.052	$ 0.043	$ 0.043	$ 0.063	$ 0.045	$ 0.051
20	$ 0.037	$ 0.042	$ 0.044	$ 0.037	$ 0.036	$ 0.045	$ 0.044	$ 0.047	$ 0.042	$ 0.048	$ 0.039	$ 0.036	$ 0.042
21	$ 0.035	$ 0.039	$ 0.044	$ 0.045	$ 0.040	$ 0.041	$ 0.045	$ 0.046	$ 0.040	$ 0.036	$ 0.033	$ 0.035	$ 0.040
22	$ 0.031	$ 0.033	$ 0.037	$ 0.037	$ 0.039	$ 0.039	$ 0.039	$ 0.040	$ 0.036	$ 0.034	$ 0.032	$ 0.034	$ 0.036
23	$ 0.031	$ 0.031	$ 0.038	$ 0.036	$ 0.034	$ 0.038	$ 0.036	$ 0.037	$ 0.035	$ 0.032	$ 0.034	$ 0.037	$ 0.035
24	$ 0.027	$ 0.026	$ 0.030	$ 0.033	$ 0.030	$ 0.031	$ 0.033	$ 0.033	$ 0.033	$ 0.029	$ 0.028	$ 0.032	$ 0.030
Avg.	$ 0.038	$ 0.041	$ 0.041	$ 0.039	$ 0.036	$ 0.042	$ 0.042	$ 0.066	$ 0.041	$ 0.038	$ 0.036	$ 0.034	$ 0.041

On Peak	Mid Peak	Off Peak				Summer	Winter	

By adjusting the PSA to reflect seasonality, AE is able to better align price signals sent to customers with the cost of power supply in ERCOT. Austin Energy's PSA recommendation works in tandem with the removal of seasonality in base rates as presented in section 6.3. These changes are supported by the rate design principles, provide incentives for energy conservation, promote the efficient use of resources, and encourage consumer investment in energy efficiency.

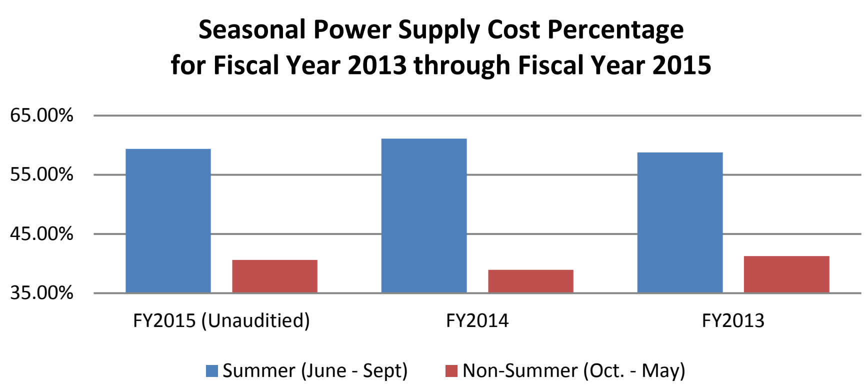
Austin Energy recommends adjusting the PSA to reflect the two seasonal periods, summer and non-summer. AE will apply a seasonal adjustment factor based on a three-year average of PSA costs. The average will use two years of historical and one year of current costs. Figure 6.22 shows the actual monthly power supply costs for FY 2013 through FY 2015 and clearly demonstrates some degree of underlying seasonality.

Figure 6.22



Applying the three-year average to the collection of PSA costs would result in 40.26 percent of costs being collected during the four summer months and 59.74 percent of costs being collected during the eight non-summer months. Figure 6.23 shows the seasonal power supply cost percentage for FY 2013 through FY 2015.

Figure 6.23



The sum of these seasonal costs is recovered from the various customer classes based on an energy usage adjusted for losses. This yields a rate per kWh, but needs to be adjusted to reflect the different level of losses associated with different service voltages. Via this process, AE is able to establish a system uniform rate per kWh for each season period that is the same for all applicable customer classes, except that losses are also acknowledged and incorporated. Thus, for both seasons, AE calculates a rate per kWh for Secondary Voltage, Primary Voltage, and Transmission Voltage. For illustrative purposes, Figure 6.24, show the existing annual PSA rate compared to estimated seasonal PSA rates that are subject to change and will be determined during the annual budget process.

Figure 6.24
Power Supply Adjustment Rates by Voltage

	Existing Annual PSA Rate ($/kWh)	Proposed Summer PSA Rate ($/kWh)	Proposed Non-Summer PSA Rate ($/kWh)
Rate before Losses	0.03124	0.02989	0.02967
Secondary Voltage	0.03139	0.03148	0.03124
Primary Voltage	0.03068	0.03076	0.03053
Transmission Voltage	0.03029	0.03037	0.03015

6.7.2. Changes to the Regulatory Charge

Just like the PSA, the Regulatory Charge is determined as part of the City's annual budget process, during which the Regulatory Charge may be adjusted to eliminate any over- or under-recovery from previous periods. Specifically, the Regulatory Charge recovers the costs associated with transmission by other utilities contained in FERC Account 565 and Texas RE and ERCOT administration fees assessed on power generation, offset by the revenue from Congestion Revenue Rights (CRR) sold via auction by ERCOT and distributed to Load Serving Entities, such as Austin Energy. The cost of transmission by other utilities is incurred by AE based on AE's load contribution to the ERCOT 4CP. Thus, each customer class' contribution to the ERCOT 4CP is the cost of service basis for allocating to that class the cost responsibility for transmission by other utilities. The ERCOT administration fees and the CRR revenues are allocated to customer classes based on NEFL.

AE proposes changing the methodology of how it calculates the Regulatory Charge. The cost will still be recovered by a kWh charge for non-demand classes and a kW charge for demand classes; however for demand classes, the charge will vary slightly, depending on the customer's voltage level (secondary, primary, or transmission). For example, if a customer moves from S1 to S2, while certain charges will change and increase, the customer's Regulatory Charge will remain the same. This change will maintain a Regulatory Charge that is in alignment with the actual cost of service on a voltage level basis and reduce inter-class cost shifting during the intervening years.

To calculate the value of this proposed Regulatory Charge, AE first addressed the unique T2 customer class situation. Because T2 operates under a separate tariff provision, the Regulatory Charge for these customers is fixed, with conditions. Thus, the costs associated with this class' Regulatory Charge were removed from the calculation so that they did not influence the costs assigned to other customer classes.

Next, AE calculated the total Regulatory Charge costs to be recovered from the residential and S1 classes based on an energy charge and separately calculated the total costs to be recovered from the remaining customer classes based on a demand charge.[136]

Austin Energy then divided the sum of costs recoverable from customer classes based on an energy charge by the total NEFL for the Residential and S1 classes. This yielded a rate per kWh which was subsequently adjusted to reflect losses. Similarly, AE divided the sum of costs recoverable from customer classes based on a demand charge divided by total demand before losses for the remaining non-residential customer classes. This yielded a rate per kW which was subsequently adjusted to reflect the different level of losses associated with different service voltages.

Using this process, AE established a system-wide uniform rate that is the same for all applicable customer classes, except that losses are also acknowledged and incorporated. AE calculated a rate per kWh for residential and S1 classes, and a rate per kW for secondary voltage, primary voltage, and transmission voltage. Figure 6.25 shows the existing annual Regulatory Charges rates compared to estimated Regulatory Charges.[137]

Figure 6.25
Regulatory Charges by Customer Class

	Res	S1	S2	S3	P1	P2	P3	T1	T2
	$/kWh		$/kW						
Regulatory Charges									
Existing	0.01414	0.01530	4.57	4.43	6.75	0.69	5.18	2.79	4.12
Proposed	0.01159	0.01159	3.24	3.24	3.16	3.16	3.16	3.12	3.98

This development approach ensures that movement of customers between customer classes, or growth in any class due to new customers, will not shift cost responsibility between classes, which can

[136] Given the very small amount of cost responsibility associated with the lighting classes as a group, and for ease of administration, AE has excluded the lighting classes from the Regulatory Charge development. The lighting classes are substantially off-peak and as a result, the Regulatory Charge costs assigned to them in total is less than $5,000.

[137] These estimates are subject to change and will be determined during the annual budget process.

create volatility in the pass-through rates. This has been an issue for AE in the past and is reflective of the differences between existing and proposed rates and from customer class to customer class. For example, P2 will see an increase in the Regulatory Charge under the new structure. In prior years, growth in the number and consumption of customers in the P2 class resulted in a significant reduction in the class Regulatory Charge, as well as significant cost savings for P2 customers. Nevertheless, a majority of classes will see a reduction.

6.7.3. <u>Changes to the Community Benefits Charge</u>

As for other pass-through charges, the City's annual budget process sets the CBC. The CBC is assessed to customers on a rate per kWh basis and recovers certain costs incurred by the utility for activities undertaken as a benefit to AE's service territory customers and the greater community. The CBC includes three specific programs and services provided to customers: Service Area Lighting (SAL), Energy Efficiency Services (EES), and CAP. Customers who receive electrical service outside City limits are not assessed the SAL portion of the CBC pursuant to the terms of the settlement agreement in PUCT Docket No. 40627.

In calculating the SAL and EES rates, AE adjusts the costs to address any prior over- or under-recovery balances as well as any revenue from other cities for outside the City street lighting. For the EES, the gradual drawdown of any over-recovery balances is over the course of three years (*i.e.*, FY 2016, FY 2017, and FY 2018). The CAP rate is set by policy, rather than calculated.

Austin Energy recommends designing and applying the SAL and EES rates on a system basis without class distinction. Austin Energy believes this change will maintain alignment with the actual cost of service and reduce inter-class cost shifting during the intervening years.

Similar to the development of the proposed Regulatory Charge, AE took into consideration the T2 tariff, which does not include SAL or EES rate components. Thus, these program costs need to be recovered without revenue from the T2 customer class.

Other customer classes pay specific portions of the CBC but not all three. For example, none of the lighting classes currently pay EES since the lighting classes are not meaningful beneficiaries of the EES programs.[138] Further, the City-Owned, Private Outdoor Lighting customer class typically has security lighting service that is not assessed the CBC and separate service provided through a primary meter which is assessed the CBC. Also, the Customer-Owned, Non-Metered Lighting and Customer-Owned,

[138] Some lighting classes have the EES rate component listed in their tariff, but the rate is currently $0 per kWh.

Metered Lighting customer classes pay the CAP and SAL charges, while Street and Traffic Lighting and City-Owned, Private Outdoor Lighting customer classes do not. Based on ease of administration, consistency across lighting classes, and recovery rationale, the lighting classes were excluded from CBC recovery in the proposed rates.

Since the CBC is charged to all customer classes based on an energy charge, the relevant net costs for SAL and EES, as shown in Figure 6.26, were divided by total NEFL for the relevant customer classes and then these resulting rates were adjusted for losses. Figure 6.26 shows by customer class the existing SAL and EES rates compared to estimated SAL and EES rates.[139]

Figure 6.26
Street Area Lighting and Energy Efficiency Services by Customer Class

	Res	S1	S2	S3	P1	P2	P3	T1
SAL Rates ($/kWh)								
Existing	0.00093	0.00096	0.00076	0.00068	0.00058	0.00054	0.00051	0.00045
Proposed	0.00145	0.00145	0.00145	0.00145	0.00141	0.00141	0.00141	0.00139
EES Rates ($/kWh)								
Existing	0.00289	0.00337	0.00378	0.00198	0.00252	0.00049	0.00114	0.00146
Proposed	0.00246	0.00246	0.00246	0.00246	0.00240	0.00240	0.00240	0.00237

As with the development of the proposed Regulatory Charge, this CBC development approach ensures that movement of customers between customer classes, if, for example, their loads change or if any class grows due to new customers, will not shift cost responsibility between classes and create volatility in the pass-through rates.

6.8. CHANGES TO DISCOUNTS

Austin Energy provides discounts to certain residential customers, ISDs and group religious worship facilities accounts. While Austin Energy does not propose making any changes to the existing residential discount program, Austin Energy proposes several adjustments to existing discounts offered to the non-residential customers. The City Council found in the 2012 rate ordinance that these benefits "are fair, just, and reasonable, and support the community priorities of well-funded public education

[139] These rates are estimates that are subject to change and will be determined during the annual budget process.

and avoidance of unplanned-for budget impacts."[140] Today however, Austin Energy recommends continuing but restructuring the ISD discount and proposes eliminating the group religious worship facilities account discount.

For the ISDs, Austin Energy recommends providing a discount of 20 percent off the base rates. Additionally, Austin Energy proposes offering an identical discount to State accounts following the expiration of the existing contract in May 2017 and to military bases as outlined in the Public Utility Regulatory Act.

While Austin Energy does not recommend continuing the group religious worship facility discount, the 20 percent floor adopted for assessing demand charges on low load factor customers will provide a significant benefit to group religious worship facilities with very low load factors.

These proposals are addressed in greater detail below.

6.8.1. Current Residential Discount Policy

Under AE's current tariffs, CAP[141] provides discounts and other benefits to qualifying low-income residential customers.[142] As of the end of September 2015, 40,931 customers (10.5 percent of the 391,430 residential customers) receive an average annual monthly discount from AE of $21.01 for a customer with usage of 1,000 kWh per month.

Eligible residential customers automatically qualify for CAP via a monthly computerized matching process conducted by a third-party vendor under contract with AE. A self-enrollment option is also available for qualifying customers not identified in the automated matching process. Each qualifying account is reviewed annually to ensure that the customer remains eligible for continued enrollment.

In response to concerns that certain customers outside of the low-income target population were being enrolled automatically in CAP, AE initiated a new screening process in fall 2015. Where data is available, each account is screened against county appraisal district data to determine if the account holder lives in an owned property with an improved value greater than $250,000. For any account

[140] City of Austin Ordinance No. 20120607-055, Part 9.

[141] A customer qualifies for the CAP discount if the customer, or a member of the customer's household, participates in any one of the following programs: the Comprehensive Energy Assistance Program (CEAP), the Travis County Hospital District Medical Access Program (MAP), Supplemental Social Security Income Program (SSI), Medicaid, Supplemental Nutritional Assistance Program (SNAP), the Children's Health Insurance Program (CHIP), Veterans Affairs Supportive Housing (VASH), or the State Telephone Lifeline program.

[142] Customers of Austin Water and the Watershed Protection Department may also be eligible for discounts and services under CAP. However, as these services are not funded through electric rates, they are not the subject of discussion in this Rates Report to Council.

where the improved property value exceeds that amount, the customer receives a notice that completion of enrollment requires the customer to contact the enrollment call center. The customer remains qualified for CAP enrollment based on a household member's participation in one of the eight assistance programs, but these customers must take an additional step to assert their qualification and complete enrollment.

Under the approved tariff, residential customers inside the City limits are assessed at $1.72 per 1,000 kWh per month. Outside the City limits customers are assessed at $1.18 per 1,000 kWh per month.[143] Non-residential customers are assessed at $0.65 per 1,000 kWh per month. A qualifying CAP customer receives a waiver of the residential $10 per month customer charge, a waiver of the CAP component of the CBC, and a 10 percent discount on the remainder of the monthly electric bill. All of the funds collected through the CBC are used to provide services directly to customers. All administrative costs for the program are expended from AE's operating budget funded through base rates.

In December 2012, AE entered into a contract with Solix Inc. (Solix) to conduct the automatic third-party qualification at an annual contract cost of approximately $500,000. While AE's new rates went into effect in October 2012, several additional months were required for Solix to design and develop its software and for it to receive access to enrollment lists from the Texas Health and Human Services Commission, leading to full implementation of the program in August 2013. As a result of the time lag, AE accumulated several million dollars in CAP funds prior to the implementation of the new enrollment process. This accumulated balance has allowed AE to provide CAP benefits to a larger number of customers — over 47,000 — until the accumulated balance is gradually exhausted, which is expected to occur at the beginning of FY 2018.

The CBC also funds the Customer Assistance Program Weatherization and Plus 1 programs. CAP Weatherization is a program offering a set of free energy efficiency services to qualifying CAP customers in need. Plus 1 is a program that offers emergency, one-time bill payment assistance. Austin Energy works through community partners to identify customers for Plus 1 assistance. Plus 1 is funded in part from the CBC, in part from AE's operations budget, and also through voluntary contributions by AE customers. Figure 6.27 shows the funding for these programs during FY 2014.

[143] Pursuant to the settlement agreement in PUCT Docket No. 40627.

Figure 6.27

Low-income Program Funding (Fiscal Year 2014)

	Community Benefit Charge ($)	Austin Energy Operating Funds ($)	Voluntary Customer Contribution ($)
CAP Discount	8,994,967		
CAP Weatherization	1,374,646		
Free Weatherization[1]	729,547		
Plus 1	532,754	367,246	147,421[2]
Solix Contract		509,239	
AE Staff Resources[3]		353,609	

1. May include Free Weatherization for both CAP and non-CAP customers.
2. Includes a one-time redirection of excess solar credits to Plus 1.
3. CAP staff only; does not include Weatherization program staff.

Austin Energy made no changes to the current residential discount policy and has kept the proposed CAP component of the CBC for residential service at the current level of $1.72 per 1,000 kWh for inside the City limits and $1.18 per 1,000 kWh for outside the City limits customers, and for non-residential customers at $0.65 per 1,000 kWh. Those charges are estimated to collect more than $11 million annually and to serve more than 40,000 customer accounts.

6.8.2. <u>Current Non-Residential Discount Policy</u>

Under Austin Energy's existing approved tariffs, ISD accounts receive a 10 percent discount off the total monthly bill. The benefit is available to all accounts associated with the eight ISDs served in whole or in part by AE. For each ISD account receiving a discount, the discount is funded by the remaining customers in the customer class of the account receiving the discount. This recovery method ensures that no cross customer class subsidies arise due to the discount policy.

The current benefit for group religious worship facilities accounts is structured not as a discount but as a rate cap on the account's total rate. The rate cap is currently set at 13.353 cents per kWh. The benefit applies only to a group worship facility's account where the meter records usage of a building housing a space primarily used for religious worship services open to the public. Other accounts associated with a worship facility such as school buildings and parking lots are not eligible for the discount. Similar to the cost recovery for the ISD discount, the rate cap for group religious worship facilities accounts is funded by the remaining customers in the customer class associated with each qualifying account.

In addition, certain State accounts (*i.e.*, state office buildings, military bases, and lighting) are currently or have been served under the Large Service Contract tariff that is closed to new accounts and applies only to certain State facilities. This contract is set to expire on May 31, 2017.

Austin Energy proposes providing discounts to the following accounts: ISDs, State accounts following the expiration of the existing contract, and military bases. Offering discounts to ISDs supports community priorities, while making discounts available to State accounts continues long-standing City Council policy. Discounts for military bases are explicitly mandated in PURA §36.354.

6.8.3. Withdrawal of Discount for Group Religious Worship Accounts

During the 2012 general rate proceedings before the Electric Utility Commission and City Council in 2011 and 2012 respectively, parties discussed the PUCT's treatment of discounts for group religious worship facilities, which in the past were commonly referred to as "church rates." The discussions recognized that discounts for group religious worship facility accounts had largely been discontinued across the state. At that time parties, were able to identify only one such discount offered by a utility subject to rate review by the PUCT, which had been approved by the PUCT as a transition mechanism. Austin Energy and participants in the proceeding were informed by that case, involving El Paso Electric (EPE), in which EPE adopted a discount for house of worship and other charitable organizations with similar usage characteristics.[144] The PUCT-approved tariff provided that the discount was to remain in effect until EPE's next general rate case. The transition was intended to give these customers more time to adjust their energy use and mitigate rate shock to their monthly bills before switching them over to the undiscounted rates.[145]

Mirroring in part the policy of the PUCT in the EPE case, the City Council approved tariffs establishing a transition maximum charge to mitigate rate shock for group religious worship customers. The City Council-approved accommodation applied a rate cap for these accounts, but contained a provision that suspended the discount for any new group worship facilities applying for service following City Council's approval of the 2012 rate ordinance. Later, City Council extended the accommodation for new group religious worship facility accounts.[146] Finally, only weekend hours were considered for

[144] *Application of El Paso Electric Company for a Discounted Rate Tariff for Churches Using Rate Schedule 24*, Docket No. 39647.

[145] This discount is still currently available. However, EPE is currently in the midst of a general rate case that proposes to phase out this discount over the next two years.

[146] Ordinance No. 20130909-003.

identifying the billed peak demand for group religious worship facility accounts. This exclusion provided a second discount for this group of customers.

In addition to the rate cap for these customers, AE staff worked proactively with group religious worship accounts to offer advice on energy management and access to energy efficiency services to assist them in managing their energy costs.

At the end of this transition period and with the opportunities extended to assist in energy management and energy efficiency options, AE recommends discontinuing the discounts to group religious worship facilities. This recommendation is consistent with actions taken by other utilities across the state, respects the transition period contemplated by the 2012 rate design, and follows active efforts on behalf of the Austin Energy to assist these accounts in managing their electricity costs. Further, the proposed protection for low load factor customers on demand rates will provide assistance to these accounts.

6.8.4. Recommendation for Uniform Structure for all Non-Residential Discounts

Austin Energy recommends that for any non-residential customer eligible to receive a discount under the new guidelines, the discount is a uniform 20 percent discount on the base rate components of the monthly bill. Foremost, this methodology is more consistent with discount provisions offered in PURA than AE's current discount structure.[147] Second, the methodology would remove the discount application on AE's pass-through charges. As AE pays all of the revenues earned from these pass-through charges to other parties and does not keep a profit for itself, providing a discount on the charges results in an additional loss of revenue for the utility. The 20 percent discount on base rates mitigates this lost revenue while providing a similar benefit to these customers.

6.9. CONCLUSIONS

Approximately one year after initiating the start of the cost of service study process, Austin Energy presents this Report to Council. Relying on extensive research by both staff and outside consultants, AE determines that a revised revenue requirement of $1.217 billion is reasonable and meets cost obligations for the 2014 test year. Adjustments considering test year data and estimates of pass-through charges expected to be assessed in FY 2017 were made to the revenue requirement and

[147] PURA does not explicitly authorize or prohibit offering discounts to ISDs, though there are provisions for offering a 20 percent base rate discount to public universities. However, PURA §36.003(b) states that rates "may not be unreasonably preferential, prejudicial, or discriminatory but must be sufficient, equitable, and consistent in application to each class of customer."

results in a an overall revenue decrease of $17.5 million. Figure 6.28 details the expected net impact of the revised Cost of Service adjusted for anticipated pass-through rates for FY 2017.

Figure 6.28

For Illustrative Purposes Only

Revenue Changes for Proposed Base Rates and Projected Pass-through Rates by Customer Class[1]

Customer Class	Proposed Base Rates and Test Year Pass-Through Rates ($)	Adjustments to Reflect Projected Pass-Through Rates ($)	Proposed Base Rates and Projected Pass-Through Rates ($)	Current Base and Pass-Through Rates ($)	Change in Revenue ($)	Change in Revenue (%)
Residential	474,057,657	-22,205,459	451,852,198	462,426,897	-10,574,699	-2.3
Secondary Voltage <10 kW	31,441,033	-287,973	31,153,060	32,190,585	-1,037,525	-3.2
Secondary Voltage 10 - <300 kW	275,044,277	-6,835,929	268,208,348	291,023,250	-22,814,902	-7.8
Secondary Voltage ≥300 kW	236,686,340	-11,249,192	225,437,148	230,692,602	-5,255,454	-2.3
Primary Voltage <3 MW	44,341,872	-2,117,752	42,224,120	47,675,638	-5,451,519	-11.4
Primary Voltage 3 - <20 MW	48,418,263	-2,488,695	45,929,568	45,846,212	83,356	0.2
Primary Voltage ≥20 MW	88,011,223	-4,266,782	83,744,440	86,739,183	-2,994,743	-3.5
Transmission Voltage	2,129,093	15,661	2,144,754	2,130,434	14,321	0.7
Transmission Voltage ≥ 20 MW @ 85% aLF	13,863,762	-1,316,755	12,547,007	12,253,293	293,713	2.4
Service Area Street Lighting	N/A	N/A	N/A	N/A	N/A	N/A
City-Owned Private Outdoor Lighting	2,884,834	-180,403	2,704,431	2,705,231	-800	0.0
Customer Owned Non-Metered Lighting	108,555	-10,023	98,532	100,589	-2,057	-2.0
Customer Owned Metered Lighting	303,411	-37,452	265,958	282,129	-16,171	-5.7
Total	**1,217,290,318**	**-50,980,755**	**1,166,309,563**	**1,214,066,043**	**-47,756,480**	**-3.9**

Notes:

1) Pass-through rates that include prior-year over/under collections are determined and adjusted during the budget process. In addition, Customer Assistance Program funding is excluded.

In this report, Austin Energy presents its detailed recommendations on how to allocate the revenue requirement and spread the revenue reduction among customer classes. Notably, the Residential customer class is under-recovered by $53.4 million. Ratemaking principles suggest gradual movement toward full cost of service recovery for each rate class; however, given the extensive gap between current and full recovery, AE recommends gradual changes to the rate design. Some of the changes mitigate potential future cost recovery erosion while others help long-term financial stability by realigning revenue collection through fixed charge recovery mechanisms. As its final recommendation for the Residential class, Austin Energy proposes that all changes remain revenue neutral at the class level for FY 2017. Exactly how best to address the under-recovery in years two through five — the longest amount of time until the next Cost of Service study is conducted — will be extensively discussed in the Impartial Hearing Examiner process and with City Council as it deliberates on these recommendations.

Secondary and Primary Voltage customer classes, on the other hand, over-contribute to the total revenue requirement (with the exception of S1, which is essentially at full cost of service). As a way to start addressing their over-recovery, Austin Energy recommends reducing the revenue requirement for these commercial classes. Considering other recommended rate changes, the $17.5 million of reduced revenue is proposed to be shared among these classes so that no class ends up with a rate increase, the design reflects a logical progression of rates as customer demand increases, and meaningful steps to move the classes closer to cost of service are taken. Like with the Residential class, additional deliberation will be required to address further movement toward cost of service for these rate classes following this proposal's implementation in FY 2017.

As debate occurs on how to treat these adjustments for both the Residential and commercial classes in years two through five, a number of options are available to City Council to move the classes closer to COS. Those tools include, but are not limited to:

- Establishing a timeframe for future, additional rate adjustments.
- Identifying a number of incremental steps used to adjust rates over time.
- Increasing the Customer Charges for the Residential class.
- Adjusting the range and number of the tiers for the Residential class.

Austin Energy intends to use any additional revenue generated by the Residential class adjustments to bring the commercial classes closer to cost of service. Once City Council selects the appropriate levers for the Residential class, then discussion can occur on how best to handle the commercial classes.

In addition to the base rate recommendations, Austin Energy proposes structural changes to the pass-through charges in order to streamline administration and ensure logical results of the rate design. Also, an extensive proposal to revamp AE's reserve policies and funding levels is offered. Following City Council's direction in 2012 and beyond, Austin Energy engaged an outside expert consultant to examine each of the utility's unrestricted reserves. Based on their analysis and internal staff consideration, AE offers a proposal to simplify the structure, recalibrate funding levels, and place a greater emphasis on maintaining 150 Days Cash on Hand. Should City Council accept these recommendations, the proposed TY 2014 revenue requirement could be reduced by an additional $8.2 million.

Over the coming months, Austin Energy staff, stakeholders, and customers will meet to review, dissect, question, and debate the assumptions, models, and conclusions of this Report to Council and Cost of Service study. Through the Impartial Hearing Examiner process, City Council will be able to review AE's proposal alongside a well-organized, independent opinion that summarizes the community dialogue and offers expert recommendations on significant issues presented in this rate review. Austin Energy staff look forward to the release of that report in mid-spring 2016.