Appendix A: Glossary of Terms

Capacity factor: The ratio of the net electricity generated, for the time considered, to the energy that could have been generated at continuous full-power operation during the same period.

Commercial Customer: Any non-residential customer who receives electric service below 12,470 volts. Examples of commercial customers include retail stores, restaurants, doctors' officers, houses of worship, and office buildings.

Congestion: The situation that exists when requests for power transfers across a Transmission Facility element or set of elements, when netted, exceed the transfer capability of such elements.

Cost of Service (COS): Studies designed to show how much classes of customers should pay for the cost they impose on the system for the use of electricity and other services offered by the utility.

Demand: The rate at which electric energy is delivered to or by a system at a given instant, or averaged over a designated period, usually expressed in kilowatt (kW) or megawatt (MW).

Electric Reliability Council of Texas (ERCOT): The independent system operator responsible for ensuring reliable and safe provision of electricity to approximately 90% of consumers in Texas. In a geographic sense, ERCOT also refers to the area served by electric utilities, municipally owned utilities, and electric cooperatives that are not synchronously interconnected with electric utilities outside the state of Texas.

Electric Utility: A person or river authority that owns or operates for compensation in Texas equipment or facilities to produce, generate, transmit, distribute, sell, or furnish electricity. This legal definition does not include municipally owned utilities, like Austin Energy.

Generation: Assets, activities, and processes necessary and related to the production of electricity.

Industrial Customer: Any non-residential customer who receives electric service above 12,470 volts. Examples of industrial customers include factories or manufacturing plants and typically have the highest demand for electricity.

Investor Owned Utility (IOU): Electric utility owned by stockholders who may or may not be customers. The IOU is a for-profit enterprise allowed to earn a pre-established rate of return for its shareholders and regulated by state public utility commissions.

Kilowatt (kW): A measure of electrical power equal to 1,000 watts.

Kilowatt hour (kWh): A quantitative measure of electric current flow equivalent to one thousand watts being used continuously for a period of one hour; the unit most commonly used to measure electrical energy, as opposed to kW, which is simply a measure of available power.

Line Losses: Difference between energy input into the Transmission Grid and the energy taken out of the Transmission Grid.

Load: a) the amount of energy used per hour or kWh, or b) a term describing a group of consumers of electricity

Load Serving Entities (LSEs): An Entity that buys energy from the ERCOT wholesale market and sells it to end-use customers or wholesale customers. LSEs include Competitive Retailers and municipally owned utilities that serve Load.

Load Size: the amount of energy used per hour or kWh.

Municipally Owned Utility (MOU): Any utility owned, operated, and controlled by a municipality or by a non-profit corporation whose directors are appointed by one or more municipalities. Austin Energy is a municipally owned utility.

Megawatt (MW): The electrical unit of power that equals 1 million watts (1,000 kW).

Megawatt hour (MWh): A quantitative measure of electric current flow equivalent to one million watts being used continuously for a period of one hour.

Nodal Market: The current market design for the ERCOT wholesale market is called the Nodal Market. In the nodal market, the electric grid consists of more than 4,000 nodes at which the energy supplied and demanded is measured at least once every five minutes. These nodes serve as the primary inputs for determining the price for electricity in the ERCOT region. ERCOT shifted to the Nodal Market in December 2010 after discontinuing the Zonal Market.

Peak Load or Peak Demand: Highest need of the system experienced during a given 15-minute interval.

Plant-in-Service: Assets currently in use by the utility.

Public Utility Commission of Texas (PUCT): Formed in 1975 by the Texas Legislature as a rate regulatory body. The PUCT now, since deregulation, oversees electric, telecommunications, and water companies to ensure Texas consumers have access to competitive utility services. The PUCT oversees competition in the wholesale and retail electricity and telecommunications markets, and regulates rates and services of certain non-competitive electric utilities, local exchange companies, and retail and wholesale water utilities.

Rate: A compensation, tariff, charge, fare, toll, rental, or classification that is directly or indirectly demanded, charged, or collected by an electric utility for a service, product, or commodity.

Rate Design: After the cost-of-service process is complete, the review process turns to rate design in which rate structures and rates, or prices, are determined. Rates must be set to recover the utility's full revenue requirement.

Residential Customer: A customer who receives electric service for domestic purposes for such needs as heating, cooling, cooking, lighting, and small appliances. Examples of residential dwellings are single family homes, apartment units, and mobile homes.

Revenue Requirement: The amount of annual revenues needed by a utility to pay all annual expenses, including debt obligations and rate of return needs.

Tariff: The schedule of a utility, municipally owned utility, or electric cooperative containing all rates and charges stated separately by type of service, the rules and regulations of the utility, and any contracts that affect rates, charges terms, or conditions of service.

Transmission and/or Distribution Service Provider (TDSP): An Entity that is a Transmission Service Provider, a Distribution Service Provider, or both, or an Entity that has been selected to own and operate Transmission Facilities and has a PUCT approved code of conduct.

Transmission Service: Service that allows a transmission service customer to use the transmission and distribution facilities of electric utilities, electric cooperatives, and municipally owned utilities to efficiently and economically utilize production resources to reliably serve its load and to deliver power to another transmission service customer.

Wholesale: The sale of any commodity to a party who intends to resell that commodity to other parties is referred to as a wholesale transaction.

Wholesale Competition: Wholesale competition is a market structure in which retail companies have a choice of two or more suppliers from whom they can purchase the commodities that they resell to their customers.

Zonal Market: In the zonal market, the electric grid was divided into Congestion Management Zones, which were defined by Commercially Significant Constraints. Several limitations were identified with the zonal market such as: insufficient price transparency, resources are grouped by portfolio, and the indirect assignment of local congestion. ERCOT discontinued the Zonal Market in December 2010 and shifted to the Nodal Market.

Austin Energy Rate Review White Paper #2a: Austin Energy's Rate Design Philosophy

Prepared for:
Austin Energy Rate Review
Public Involvement Committee

Released: January 26, 2011

White Paper #2a:

Prepared for: Austin Energy Rate Review Public Involvement Committee Meeting No. 2

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Austin Energy's Rate Design Philosophy

Introduction

All utilities are guided by their strategic objectives when designing and setting rates and those objectives provide a framework for developing the utility's rate design philosophy. White Paper #1 included among other topics an overview of Austin Energy ("AE") and its Strategic Plan and introduced the concept of aligning AE's rate structures with the utility's policies and strategic objectives. This white paper provides further detail on AE's strategic objectives, describes how those objectives are related to rate design, and outlines AE's rate design philosophy. This document serves as a guide for redesigning electric rates during the rate review process. A one-page summary of AE's guidelines for redesigning electric rates is also available as a resource document for members of the Rate Review Public Involvement Committee ("PIC") and the general public.

Austin Energy's Strategic Objectives

Austin Energy is governed by the Austin City Council ("Council" or "City Council") on all business and strategic matters. Council determines the strategic direction of the utility given input from utility management and the community.

Mission Statement

Austin Energy's strategic objectives are summarized by its mission statement and further outlined in its Strategic Plan.

Austin Energy Mission Statement: To deliver clean, affordable, reliable energy and excellent customer service.

In support of its mission, AE has implemented new programs, added services, and invested in new assets that contribute to the utility's goals and objectives.

Austin Energy has taken many actions over the past decade that are tied to the foundational principles of AE's mission statement. A description of each of those principles is provided below with examples of major initiatives of the utility to demonstrate how AE is guided by its mission statement and strategic objectives.

Affordable Energy – Austin Energy recognizes that it must assure that the cost of electric service remains affordable for all customers. Austin Energy has a history of providing electricity to customers at some of the lowest prices in Texas while providing incentives to lower energy consumption and improve the energy efficiency of homes and buildings, further lowering electric bills. Through initiatives such as power generation mix diversification and promoting energy efficiency and conservation, electricity has remained affordable for AE customers.

Example Initiatives:

- Resource Diversity – Austin Energy has built a diverse portfolio of power generation resources to reduce cost risks associated with each type of energy resource. Austin Energy currently generates electricity from a mix of coal, natural gas, nuclear, and renewable resources including wind and biogas.
- Fuel Hedging Program – Natural gas price volatility is one of the greatest cost risks for an electric utility. Austin Energy manages a fuel hedging program to help manage short-term price volatility and limit the impact to customer bills caused by natural gas price swings.
- Money-Saving Energy Efficiency and Conservation Programs – Austin Energy manages a comprehensive set of energy efficiency and conservation programs for residential and commercial customers that includes rebates and loans for home and building energy improvements and incentives for improved management of energy usage. Such improvements reduce the amount of energy needed to provide the same level of service, thus lowering electric bills. This also helps the utility avoid the high capital cost of new power plants, keeping costs low for all customers.
- Customer Assistance Program – Austin Energy manages a comprehensive Customer Assistance Program to help customers on low and/or fixed incomes manage their overall utility costs. Services offered through this program include utility bill discounts, emergency bill payment assistance, and free home energy improvements for income-eligible customers.

Reliable Energy – Austin Energy recognizes that customers need and expect reliable electric service (i.e. keeping the lights on). Austin Energy is continually reinvesting in its existing infrastructure and making new investments in the electric system to meet evolving customer needs. Austin Energy ranks at the top of utilities in measures of reliability. Maintaining a highly reliable system has also minimized the cost of lost productivity associated with power outages, contributing to the affordability objective for customers.

Example Initiatives:

- System Investment – Austin Energy maintains an electric system that includes more than 10,000 miles of power lines, 67 substations, 77,000 transformers and 145,000 power poles. Austin Energy continuously upgrades its electric system to maintain the highest level of system reliability.
- Smart Grid/Advanced Metering Infrastructure – Austin Energy began building its smart grid system in 2003 and its service territory is now completely served by advanced meters. This advanced system will improve system security, allow for greater system control by the utility and its customers, lower the number and length of outages, and provide new opportunities for customer management of energy use and new electricity pricing models.
- Outage Management – Austin Energy system reliability outperforms industry standards, which means that the number and average duration of power in

Austin is less than industry averages. Austin Energy linemen are always on standby with loaded vehicles, ready to respond to power outages 24/7.

- Tree Trimming Program – An important contributor to excellent system reliability is tree trimming, since trees are the number one cause of outages during storms. Austin Energy trimmed 480 miles of trees in Fiscal Year 2009.

Excellent Customer Service – Austin Energy strives to provide excellent customer service by handling all service requests and inquiries efficiently and satisfactorily and developing programs that bring excellent value to all of our diverse customer types. Austin Energy's Customer Care business unit manages the City of Austin call center, a Key Accounts group, and programs to assist low-income and other disadvantaged customers.

Example Initiatives:

- Payment Simplicity – City of Austin utility customers can go online to review monthly electricity usage and manage their utility account. Customers may pay their bill through multiple methods and walk up locations.

- Customer Support – Austin Energy manages the Austin 3-1-1 call center which is the 24/7 primary call center for City of Austin services and the Office of Homeland Security and Emergency Management. In 2009 the call center handled more than a million calls and issued over 170,000 service requests. Austin Energy also manages a Key Accounts group to provide additional customer assistance to large commercial and industrial customers who have unique power quality and reliability needs.

- Levelized Billing and Payment Plans – Levelized billing allows customers to pay the same utility bill amount each month by averaging payments based on historical information and adjusting each year for any changes in consumption amounts. Customers also have the opportunity to set up payment plans to help manage bill payments.

- Community Investment – As a community-owned electric utility, the portion of revenues that would otherwise be distributed as profits to stockholders around the state, the country, or the world are invested back in the community to help pay for public safety, parks, libraries, and other community services. This helps reduce fees and taxes needed to fund city operations.

Clean Energy – Austin Energy recognizes that it has a responsibility to provide clean energy to its customers and protect our natural environment. Austin Energy offers a renewable energy pricing option to its customers through its GreenChoice® program, provides rebates to customers who make home and building energy improvements and install solar photovoltaic systems, and continues to add new renewable energy resources to its power generation mix.

Example Initiatives:

- GreenChoice® Program – Austin Energy manages the nation's most successful utility-sponsored voluntary green pricing program in terms of total sales of renewable energy to program participants.

- Energy Efficiency and Conservation Programs – Between 1982 and 2007, AE's energy efficiency and conservation programs offset the equivalent of a 700 MW power plant, providing environmental benefits to local and regional communities. That is enough electricity to power 400,000 homes and is the least expensive and cleanest way to meet electric demand from a growing population and continued economic development. Austin Energy has a goal to offset the need for a 800 MW power plant by 2020 from the baseline year of 2007.

- Solar Incentives – Austin Energy offers rebates and loans for customers installing solar photovoltaic systems as well as performance-based incentives for commercial customers.

- Investment in Renewable Resources – Austin Energy currently generates about 10 percent of its energy from renewable resources with over 400 megawatts (MW) of wind capacity and about 12 MW of biogas capacity. Austin Energy is currently under agreement to purchase power from a 30 MW solar plant beginning in 2011 and a 100 MW biomass plant beginning in 2012. Austin Energy has the long-term objective of 35 percent renewable generation by 2020.

- Environmental Initiatives – Austin Energy has developed strategies and initiatives to reduce power plant emissions such as carbon dioxide (CO_2), nitrous oxides (NOx), and sulfur dioxide (SO_2) by installing pollution control equipment at its power plants and designing operational strategies to reduce emissions. An example pollution strategy is the current installation of SO_2 scrubbers at the Fayette Power Project which will reduce SO_2 emissions from our only coal-fired power plant by 95 percent.

Strategic Plan

In addition to the principles articulated in AE's mission statement, AE adopted its Strategic Plan in 2003 (with updates as recent as 2010) which established a series of strategic objectives to help AE 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. Austin Energy's latest update to its Strategic Plan can be accessed at:

http://www.austinenergy.com/About%20Us/Newsroom/Strategic%20Plan/strategicPlan.pdf

In 2007, the Council adopted the Austin Climate Protection Plan, an aggressive community-wide plan to address global warming which included carbon reduction goals for the utility. These goals complement the Strategic Plan's objectives of preparing the utility to meet future needs and demands while considering financial risks associated with potential regulation of greenhouse gases. In 2010, AE released its *Resource, Generation, and Climate Protection Plan to 2020* ("Resource Plan") which serves as a resource planning tool that brings together demand and energy management options over a planning horizon. The Resource Plan establishes clean energy goals, commits to continuing to provide affordable electricity to customers, and continues to stress the electricity reliability and improved customer service targets set forth in the Strategic Plan. Details on AE's Resource Plan can be accessed at:

http://www.austinenergy.com/About%20Us/Environmental%20Initiatives/climateProtectionPlan/index.htm

Austin Energy's key strategic objectives and most recent targets for each objective are summarized below.

- *Risk Management:*
  - Maintain financial integrity
  - Reduce CO_2 by 20 percent below 2005 level by 2020
- *Excellent Customer Service:*
  - Create and sustain economic development
  - Improve customer satisfaction
  - Improve employee satisfaction
  - Provide exceptional system reliability
- *Energy Resources:*
  - 800 MW of energy efficiency by 2020
  - 35 percent of energy from renewable resources by 2020
  - 200 MW of installed solar generation by 2020
  - 1,000 MW of wind by 2020

Alignment of Rate Structures with Strategic Objectives

As demonstrated above, AE's programs and investments are guided by its mission statement and Strategic Plan. A key challenge of this rate review is to achieve an outcome that will help promote and achieve AE's mission and Strategic Plan while ensuring long-term financial stability for the utility. For AE to successfully continue achieving these multiple objectives, new rate structures and rates are needed that support these objectives. Achieving the goal of 800 MW of energy efficiency is one example. Austin Energy's residential and commercial rate structures must be designed to encourage customers to conserve energy and make investments in energy efficiency improvements. If this rate review is not successful in establishing a rate design that promotes AE's strategic objectives, the utility will face a greater challenge to maintain financial stability and achieve its goals. Therefore, additional revisions to AE's rate structures will be required in the future.

Austin Energy's Rate Design Principles

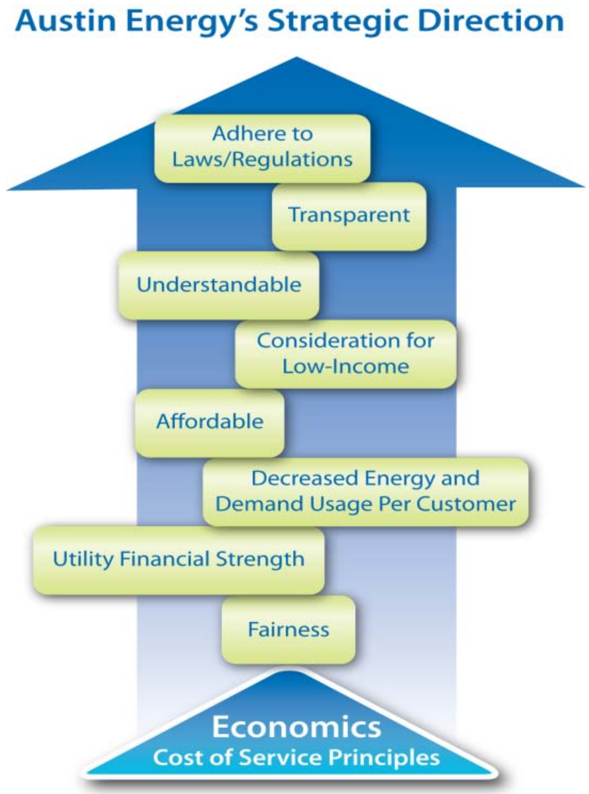
In order to help facilitate discussion at PIC meetings and among the general public, AE has developed a set of rate design principles in alignment with AE's strategic objectives and specific to the rate review process:

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

In essence, these principles compose AE's rate design philosophy. These rate design principles serve as a framework for redesigning electric rates during the rate review process and will be referenced in future white papers and presentations to demonstrate consistency between AE's proposed rate structure changes and its strategic objectives.

The ten guiding rate design principles are illustrated in Figure 1. The graphic is designed to illustrate that AE believes that rate design must be founded on economic principles such as cost of service while moving in line with the utility's strategic direction. All principles illustrated between those two core foundational principles are grounded in industry ratemaking best practices and representative of local community values.

Figure 1
Austin Energy's Rate Design Principles



Austin Energy's 10 rate design principles are described in more detail below.

1. Rates should be in alignment with the Austin Energy's strategic objectives.

The rates designed during AE's current rate review process must compliment AE's policies, goals, and strategic objectives. Rate structures in misalignment with the utility's strategic objectives can adversely impact initiatives taken by the utility to achieve those objectives and ultimately harm the overall financial stability of the utility. Additionally, misalignment between rates and strategic objectives may send contradictory or confusing pricing signals to customers or negate incentives provided by the utility to support energy efficiency and conservation, clean energy technologies, and other emerging technologies the utility supports.

This objective must be considered throughout the ratemaking process and in all aspects of AE's rate design philosophy. Austin Energy will take the following actions to meet this objective:

- Develop rates that will allow AE to successfully continue to provide clean, affordable, reliable energy and excellent customer service;
- Develop rates that support the financial strength and integrity of the utility; and

- Develop rates that promote the efficient use of resources and conservation of energy.

2. ***Ratemaking should be founded on economic standards common to the electric utility industry.***

This objective provides the foundation of AE's rate design philosophy and is the core principle of effective ratemaking. The economic standards of ratemaking include cost of service analysis as a basic standard of fairness and reasonableness, avoidance of undue discrimination, effectiveness in yielding total revenue requirements, revenue stability, consideration of value of service, offering competitive prices, considerations of the impact of rate structures on consumer behavior and efficient use of resources, and a fair rate of return. These ratemaking principles are captured and enumerated in the writings of industry thought leaders such as Alfred Kahn and James Bonbright and have been applied to the ratemaking practice for over 35 years.

Rates should be designed, to the degree practical, to reflect the actual cost of providing services to different customer types while promoting the efficient use of resources. Electric utilities are entrusted with a significant portion of the world's natural resources and are thus obligated to support the efficient utilization of those resources. As well, AE is entrusted with the financial capital of the community and is obligated to utilize those financial resources efficiently. Rates should be designed to provide the appropriate pricing signals for customers and promote the efficient use of utility assets and natural resources.

Austin Energy will take the following actions to meet this objective:

- Follow ratemaking best practices and industry standards;
- Set rates at levels that ensure revenue stability;
- Establish customer classes based on similar cost of service characteristics;
- Prepare an unbundled cost of service analysis that identifies the key cost elements of serving each class of service; and
- Design rates that are in alignment with cost of service results and minimize subsidizations that are contrary to promoting efficient use of resources.

3. ***Rates should be fair between customer classes.***

While the concept of fairness is subject to interpretation, a cost of service analysis provides the basis for developing fair and equitable rates among different customer types and customer classes. Deviations from the strict cost of service results may be deemed necessary to support the strategic objectives of the utility and values and needs of the community. When deviating from strict cost of service, the concept of fairness should be applied to determine how best to distribute those costs among customers.

Austin Energy will take the following actions to meet this objective:

- Prepare an unbundled cost of service analysis that identifies the key cost components necessary to serve each customer type;
- Gather feedback from the community and identify community objectives and needs which may not be cost-based; and
- Design rates in alignment with cost of service results and in consideration of community objectives and needs.

4. Rates should ensure the long-term financial strength of the utility.

Of upmost importance is the development of rates that ensure AE's long-term financial strength. Without financial stability, the utility could face severe financial consequences, including the inability to meet its strategic objectives and targets.

Austin Energy's load growth has declined in recent years in part due to the recent economic downturn and in part due to reduced energy consumption as a desired result of the successful implementation of demand-side management programs that support energy efficiency and conservation. However, declining load growth necessitates that revenue recovery be achieved at a reduced level of sales, requiring a cost recovery structure that more adequately captures fixed costs incurred by the utility.

Austin Energy will take the following actions to meet this objective:

- Set rates at levels that fully recover the utility's revenue requirements;
- Provide pricing signals to customers that promote consumption patterns that support system efficiency and lower costs;
- Design rates that improve fixed cost recovery, reducing dependency on energy usage levels; and
- Design rates that pass highly variable cost components (such as fuel) on to customers through the application and use of rate adjustment mechanisms.

5. Rate structures should provide incentives for energy conservation, promote the efficient use of resources, and encourage consumer investment in energy efficiency.

Austin Energy's Strategic Plan emphasizes demand-side management strategies as cost control mechanisms for the utility and its customers. Austin Energy has made significant investments in energy efficiency over the past several decades. Energy efficiency and conservation programs provide additional environmental benefits to the community. Rate structures can be developed that promote energy conservation and consumption patterns that promote the efficient use of resources by sending pricing signals to customers, particularly those customers with high consumption and/or inefficient consumption patterns. To encourage conservation, rates may be structured in blocks where the cost of power increases as consumption rises, a pricing structure known as tiered rate structures or inclining block rates. Additionally, demand charges and time-of-use pricing structures can be considered as long-term objectives to provide pricing signals to shift consumption to times when it costs less to produce and deliver the electricity. Such rate structures empower customers to better manage their energy consumption and potentially lower their electric bills.

However, such rate structures tend to reduce overall system load growth and can increase volatility of the revenue stream. In order to lessen the negative impacts of growth decline, AE must recover a greater portion of its fixed costs through fixed charges. This is in alignment with the objective of preserving the financial strength and integrity of the utility.

Austin Energy will take the following actions to meet this objective:

- Consider tiered rate structures that promote energy conservation and efficient use of resources;
- Ensure adequate cost recovery based on analysis of expected energy consumption changes influenced by new rate structures and improvements in fixed cost recovery mechanisms; and
- Consider new rate structures and future rate development strategies that empower customers to better manage their energy usage and provide improved pricing signals.

6. Rates should maintain the affordability of electricity.

Austin Energy's recognizes the need to maintain the affordability of electricity for all customers. However, this objective may at times be in conflict with the need to raise rates to meet rising costs. Given these economic realities and AE's strategic objectives, affordability can best be achieved by phasing-in rate structure changes that promote the most efficient use of resources in the long-term. By promoting energy conservation and energy efficiency improvements, electricity bills can remain low even when rates increase.

Austin Energy will take the following actions to meet this objective:

- Continue to aggressively control costs. Austin Energy will continually evaluate the efficiency of its operations and assets to keep its costs as low as possible;
- Continue to aggressively promote energy efficiency and conservation through existing programs by developing new programs and rate structures in accordance with this strategic objective; and
- Continue to provide discounts and other forms of assistance for low-income and other disadvantaged customers.

7. Provide a discount to low-income customers.

Austin Energy is owned by the community it serves and thus its policies and programs reflect the values and social concerns of that community. Austin Energy recognizes its obligation to provide electric service to all members of the community, including low-income customers and other disadvantaged customers. Austin Energy has historically offered discounted rates and other forms of assistance to income-eligible customers. It is important that these policies continue with the development of new rate structures and that new opportunities for enhancing those services be explored.

Austin Energy will take the following actions to meet this objective:

- Continue to offer discounts and other forms of assistance to low-income and other disadvantaged customers;
- Continue to support programs that improve the efficiency of homes of low-income customers and other disadvantaged customers; and
- Continue to provide bill payment and management assistance programs to help low-income customers and other disadvantaged customers budget and pay their bills.

8. Rates should be as simple and understandable as practical.

To be effective in achieving underlying objectives, rates and pricing signals, communicated through a customer's electricity bill or other communication mechanisms, must be understandable for all customers. Additionally, effective ratemaking should send pricing signals that enable customers to respond in an intended manner. If rates are overly complex, it is difficult for customers to understand the relationship between energy usage and cost and how their energy consumption behaviors influence that relationship. Additionally, customer bills should be comparable with those of other electric utilities so that the utility and customers can make comparisons.

The objective of simplicity and understandability is becoming more difficult to achieve as the regulatory environment in which AE operates becomes increasingly complex. Regulatory policies in Texas have led to new costs and charges that must be passed on to customers. Additionally, an increasing number of customer choices in the competitive retail markets, interest in emerging technologies such as distributed renewable generation and electric vehicles, and time-of-use pricing and other dynamic pricing options can add an additional level of complexity to customer bills.

Austin Energy will take the following actions to meet this objective:

- Design rates that are practical, useful, and valuable;
- Design rates using a public process that is open and transparent so that customers have the opportunity to evaluate new rate structures; and
- Vet new and potentially complex rate structures in a public process and, when appropriate, implement pilot programs to evaluate the potential impacts of potentially complex rate structures.

9. The rate review process should be transparent, including public involvement.

Austin Energy is committed to disclosing information relevant to the rate review process and soliciting feedback from the community throughout the process. For this reason, AE has developed an extensive public involvement process involving all of the diverse customer types the utility serves. This process will be conducted in a transparent manner. This objective of transparency will help ensure that rates are designed fairly and in accordance with the objectives and needs of the community.

Austin Energy will take the following actions to meet this objective:

- Establish a public involvement process during and following the rate review study period to solicit feedback on any proposed changes to rate levels and rate structures;
- Establish a public involvement committee comprised of representatives of all customer types and interest groups to provide a forum for dialogue on rate issues and solicit feedback from those representatives;
- Maintain openness and transparency during the process including the release of rate review information and study results to the general public; and
- Establish public proceedings before the Electric Utility Commission and the City Council to review any proposed changes to rate levels and rate structures.

10. The rate review process must adhere to laws and regulations.

From a cost of service and rate setting perspective, AE must comply with the laws and regulations set by its governing bodies and regulatory entities as well as contractual obligations and financial covenants. Austin Energy must meet the requirements set forth in bond covenants related to reserve funding levels and debt service coverage. Another significant legal financial obligation is AE's General Fund Transfer which is set by covenant.

Austin Energy is governed by the Austin City Council in the setting of rates and the Council must ultimately approve any changes to electric rates. Additionally, AE's transmission function is regulated by the Public Utility Commission of Texas ("PUCT"). The PUCT also sets forth specific guidelines with respect to cost accounting standards (use of an accounting "chart of accounts" as prescribed by the Federal Energy Regulatory Commission ("FERC")) and revenue requirement determination. Austin Energy intends to ensure its ratemaking process and final approved rates are consistent with requirements of the PUCT.

Austin Energy will take the following actions to meet this objective:

- Conduct public proceedings at the Electric Utility Commission and the Austin City Council prior to approval of any proposed changes to rate levels or rate structures;
- Establish a revenue requirement and design rates that meet the financial policies of AE including all legal commitments and obligations to creditors and the City of Austin; and
- Follow the standards, guidelines, and requirements of the PUCT and FERC guidelines for cost accounting.

Challenges and Opportunities

Austin Energy faces the overarching challenge of designing new rates that allow the utility to continue to provide clean, affordable, reliable energy and excellent customer service. Austin Energy must ensure its continued financial strength by updating its outdated rate structures in alignment with its strategic objectives. This will be accomplished by following the rate design principles outlined above. While AE recognizes that it faces many challenges during the rate review, it also recognizes that this rate review provides an opportunity for AE to maintain its role as a leader in the local community and the electric utility industry.

This rate review provides an opportunity for AE to leverage its previous investments and complementary strategic initiatives, some of which were outlined in the discussion of AE's strategic objectives above. Major initiatives to be leveraged during this rate review include investment in energy efficiency and conservation, investment in AE's advanced metering infrastructure and development of a smart grid system, AE's Green Building Program and expected future building code changes, promotion of vehicle electrification, investment and promotion in solar photovoltaic systems on rooftops, and the various initiatives of the Pecan Street Project, to name a few. Promoting these initiatives will help AE achieve its strategic objectives and meet its goal as a community and industry leader.

Austin Energy recognizes the following opportunities presented by this rate review process that can be achieved by following AE's rate design philosophy.

- **Ensure AE's continued financial strength and integrity.** Rates will be designed to ensure the continued financial strength and integrity of the utility is maintained.

- **Align customer costs with rates.** The detailed cost of service study results will provide information on how costs are incurred by each customer class and the component of these costs so that AE can redesign rates that are as close to true cost of service as practical given other social objectives.

- **Design rates in a manner that reflects the way AE incurs costs**. Austin Energy plans to use this opportunity to more closely align its rate structure to reflect the way it incurs costs. In Fiscal Year 09, fixed revenue represented 21 percent of total revenue, while 57 percent of the utility's costs were fixed. During the rate design process AE will look at options to increase collection of fixed revenue such as adjusting the monthly customer charge or demand charge to increase the proportion of total revenue charges that are fixed.

- **Continue to promote energy efficiency and conservation.** Austin Energy's rate structure will be designed to continue to support energy efficiency and conservation. Inclining block rates and expanded use of demand charges and time-of-use pricing will be considered.

- **Empower customers through pricing signals and new information**. Austin Energy will leverage investments in advanced technologies such as smart meters and its new billing system capabilities to explore rate structures that provide customers with improved price signals and energy usage data. This will empower customers to be more informed and subsequently have more control over their utility bill and associated electricity costs.

- **Develop rates for new customer types.** Austin Energy will consider implementing new rates for emerging customer types such as owners of distributed solar generation and/or electric vehicle owners. This supports emerging technologies that AE has made prior investments in promoting.
- **Target low-income customer assistance provisions.** Austin Energy will use this opportunity to review its Customer Assistance Program and the provision of discounts for low-income and other disadvantaged customers.

REPORT | March 19, 2015

SMALL COMMERCIAL CUSTOMER DEMAND CHARGE STUDY

Austin Energy

Austin, Texas

PREPARED BY:

NewGen Strategies & Solutions

ECONOMICS STRATEGY STAKEHOLDERS SUSTAINABILITY

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EXECUTIVE SUMMARY

Some of the changes to the rate design resulting from the 2011 Rate Study had a significant impact on certain Secondary Voltage Greater than or Equal to 10 kW but Less than 50 kW (S2) customers' monthly electric bills. To better understand the cause of these bill impacts and the appropriateness of the current S2 rate design, Austin Energy (AE) retained NewGen Strategies & Solutions (NewGen) to examine the change in S2 customers' electric bills since the October 1, 2012 implementation of new rates. Specifically, NewGen has analyzed the historical usage characteristics of S2 customers to determine if the allocation of costs in the 2011 Rate Study was appropriate; examined historical S2 customer bill impacts with specific attention to the introduction of a demand charge to customers with monthly maximum demands between 10 kW and less than 20 kW; and compared the S2 rate structure with the rate structures of other utilities in Texas and across the country, all with the goal of determining if the current S2 rate structure is equitable and appropriate.

Rate Design Objectives

The S2 rate structure, along with other AE retail rates were designed to meet specific objectives that align with AE's long run business objectives. These business objectives, among other things, promote the environmentally responsible and efficient use of energy. Under this business paradigm, AE is incentivizing customers to use less energy. An effective rate structures is designed with the intention of supporting these objectives. Recognizing the rate design implications identified in the 2011 Rate Study, the following rate design objectives were established:

1. Ensuring the long-term financial strength of the utility by setting rates that meet AE's revenue requirement and achieve sustained revenue stability;
2. Improving fixed cost recovery to align AE's rate structure more closely to its cost of serving its customers;
3. Aligning rates with AE's Strategic Plan by designing rates that encourage efficient energy use and meet changing customer needs by supporting technologies like solar electricity generation and electric vehicles; and
4. Updating rates and rate structures to distribute costs fairly among customer classes and encourages efficient energy use.

Commercial Class Rate Design

With the above rate design objectives in mind, AE reviewed historical customer class designations and established the following three new commercial classes.

Class	Criteria
S1 Secondary Service	0 < 10 kW
S2 Secondary Service	10 < 50 kW
S3 Secondary Service	50 + kW

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Justification for these changes to commercial secondary voltage customer classes was as follows:

- Customer usage characteristics indicated that customer monthly load factor, size (measured in kW) and coincidence with the AE system peak varied significantly at usage levels of less than 10 kW, equal to or greater than 10 kW but less than 50 kW, and 50 kW or more. These changes resulted in cost of service differences between these three groups of customers.
- PUCT regulation of Transmission and Distribution Utilities (TDUs) operating in the deregulated retail markets in Texas made a rate design distinction at 10 kW, where customers with maximum monthly demand of less than 10 kW did not have demand charges and customers with maximum monthly demands of 10 kW or greater did have demand charges. Given that AE's rates may be reviewed by the PUCT, commission precedent was an important consideration.
- Expanding the application of demand charges to smaller commercial customers improved fixed cost recovery and encouraged these customers to reduce demand or improve efficiency as measured by monthly load factor.

Alignment of S2 Class Rate Design with Cost of Service Results

NewGen reviewed the S2 rate design with the 2011 Rate Study cost of service results and found the following.

- ***Rate design aligns with cost of service results.*** Cost of service principles dictate that customer monthly load factor, rather than size (as measured in kW), is a primary indicator of average cost. Load factor is defined as average load divided by peak load over a predefined period, and is a measure of efficiency where a higher value (closer to 100 percent) is more efficient. Approximately 47 percent of S2 customers have average monthly load factors of 30 percent or less. AE's S2 rate structure is in alignment with cost of service results and principles – more efficient high load factor customers have a lower average rate than less efficient low load factor customers.
- ***Customer usage characteristics are different than those used in the 2011 Rate Study.*** Recent customer usage characteristics for S2 customers differ from the class usage characteristics used in the 2011 Rate Study. Differences pertain to customer size (as measured in kW), monthly energy usage, monthly load factor, and seasonality of load. Because these differences do not impact cost allocation in a uniform manner, the impact of these differences on cost of service results pertaining to the S2 class are unknown until an update of the cost of service analysis is completed.

Impact of Commercial Rate Design on S2 Customer Usage Characteristics

Customers in the S2 commercial class have maximum demand in the months June through September of between 10 kW and less than 50 kW. As a result of changes in rate design and customer class designations, customers with maximum demand in the months June through September of between 10 kW and less than 20 kW were introduced to a demand charge and, if applicable, a power factor penalty charge for the first time. Given these changes, NewGen reviewed the impact on all customers in the S2 class using information provided to us by AE. Based on our review of this information, we have reached the following conclusions:

- ***Pricing signals associated with the S2 rate structure appear to be accomplishing rate design objectives as established in the 2011 Rate Study***. AE's S2 rate structure appears to be lowering the class contribution to on-peak demand, promoting conservation and efficiency, and improving AE's fixed cost recovery.
- ***AE's current power factor penalty threshold of 90 percent is reasonable compared to its peers in the industry.*** Power factor penalty charges are uniformly applied throughout the industry to recover the added cost associated with serving customers with electric motors or other loads that reduce the efficient delivery of real power to customers. These penalties are often assessed via the demand charge. From a cost of service perspective, power factor penalty charges are an equitable means of recovering costs directly from customers adding costs to the system.
- ***A relatively small number of S2 customers with low monthly load factors and poor power factors have experienced large increases in their monthly power bills.*** Prior to the creation of the S2 class, approximately 1,475 of the 7,442 customers now in the S2 class who have monthly demand between 10 kW and 20 kW, or about 20 percent of S2 customers currently paying power factor penalty charges, were in a non-demand rate class and, therefore, were not subject to power factor penalty charges. These customers experienced greater bill impacts as they were introduced to a demand charge and a power factor penalty charge simultaneously when the S2 class was formed.

Customer Feedback

Based on our observation of S2 customer feedback as conducted by Creative Consumer Research and direct phone conversations with two customers who have expressed concern over the S2 rate to the Austin City Council, as discussed in Section 4 of this report, NewGen reached the following conclusions:

- ***At the class level, there appears to be limited concern over the impact of the S2 rate on customer finances.*** This is evidenced by the general difficulty in getting customers to attend a customer feedback discussion on this issue.
- ***Some customers are reacting to the S2 pricing signals by considering investments in energy efficiency or changes in energy use***. Customers who did participate in the feedback session did indicate that some customers are reacting to the S2 pricing signals by considering investments in energy efficiency or changes in energy use. The focus group conducted by Creative Consumer Research indicated most customers are supportive of the goals of the demand rate structure, including charging customers that cause additional cost more for service. These responses are in alignment with AE's 2011 Rate Study objectives.
- ***One customer that contacted Austin City Council felt the rate being charged to him was unduly burdensome.*** NewGen attempted to survey select customers that had contacted Austin City Council in order to gather direct feedback on S2 rate design bill impacts. A total of six customers were called and two customers were surveyed. One customer contacted felt the rate being charged to him was unduly burdensome. The

customer's monthly power bill has increased dramatically under the S2 rate structure as this customer's usage characteristics resulted in maximum demands of 33 kW, low monthly load factors, and poor power factor as the business operation requires use of a significant amount of motors. This customer might benefit from an energy audit to identify cost-effective means to reduce their electric bills.

- ***Concern over the S2 rate structure and the impact on customer bills appears to be limited to a small group of customers with low load factors and poor power factors.***

Benchmarking

Based on our benchmarking analyses, as discussed in Section 5 of this report, NewGen reached the following conclusions:

- ***For small commercial customers, there is no standard approach in determining commercial class size.*** Customer class sizes range significantly between utilities. Of the utilities benchmarked, the Texas utilities have customer classes that include customers between 10 kW and 50 kW in the same rate class, consistent with the current S2 class. In utilities benchmarked outside the state of Texas, a greater variation of small commercial rate classes was identified; for example, Sacramento Power identifies rates for customers with 10 kW to 20 kW monthly demand and a separate rate for customers with 20 kW to 299 kW of monthly demand.
- ***For small commercial customers, there is no standard rate design approach.*** Customer class sizes, as measured in kW, range significantly between utilities. Most utilities, but not all, have a small commercial class that does not have a demand charge. However, two utilities in the benchmarking analysis (CPS Energy and Los Angeles Department of Water and Power) have demand charges, or similar charges, applicable to all commercial customers regardless of size. Conversely, three utilities in the benchmarking analysis (Bluebonnet Electric Cooperative, Pedernales Electric Cooperative, and Reliant/CenterPoint) do not apply demand charges to any small commercial customers.
- ***For those utilities that do have demand or similar types of charges for these small commercial customers, the demand charges are lower than AE's in most cases.*** For customers with maximum demands ranging from 10 kW to 20 kW, the benchmarking results were similarly mixed. Of the eight utilities included in the benchmarking study, five do not have a demand, or similar, charge and three do have a demand, or similar, charge.
- ***All things considered, AE's current S2 rate structure impacts all customers in the class (10 kW - 50 kW) in a similar manner as that of CPS Energy, Los Angeles Department of Water and Power, and TXU/Oncor (as well as Sacramento Municipal Utility District for some S2 customers).*** It is worth noting that CPS Energy has a rate mechanism in place to shield low load factor customers from significant bill impacts, which is something that does not currently exist in AE's S2 rate structure.
- ***If AE were to adopt a rate structure similar to most utilities included in this benchmarking analysis, the most likely result would be a shift of costs from low load factor customers to high load factor customers, contrary to the intent embedded in the rate design adopted by the Austin City Council in 2012.*** Approximately, 47 percent

of S2 customers have average monthly load factors of 30 percent or less and 53 percent have monthly load factors of 30 percent or greater.

Alternate Rate Structures

Based on our review of hypothetical rate changes to the S2 customer class, as discussed in Section 6 of this report, any rate change that reduces or eliminates the current S2 demand charge will shift costs from low load factor customers to high load factor customers. Such a shift would be contrary to cost of service principles and would not align with the rate design objectives identified by AE in the 2011 Rate Study.

Further, simply adjusting the rate for customers in the 10 kW to 20 kW range of demands will not necessarily assist “small, local” businesses, as some of these businesses exhibit much larger demands in their operations. Thus, if an objective is to support the small, local business community in Austin, altering the rate for customers in a narrow range of demands will be an imprecise means to achieve this policy goal and many of the intended beneficiaries of such a policy would not be assisted by this change. Other support, such as energy audits or efficiency investment subsidies, could be more targeted to the intended recipients and, thus, would likely achieve a much better outcome.

Recommendations

Based on our analyses, NewGen recommends AE update the detailed customer usage information for the S2 class in AE’s next cost of service study to capture more accurately the current cost of service implications for this class of customers based on changes to their usage characteristics and additional data provided by the wider use of demand meters. AE should also perform a detailed multi-year weather normalization study for the S2 class to clearly understand the influence of the current rate structure on customer electricity consumption patterns.

To the extent possible, AE should maintain current pricing signals as they reflect cost of service results and customer reactions to these signals generally appear to be meeting the utility’s rate design objectives. However, AE should consider options to minimize “rate shock” for low load factor and poor power factor customers.

In the short term, for the S2 customer class, AE may consider temporarily rolling back the power factor penalty charge from 90 percent to 85 percent until the next comprehensive rate review. This adjustment would reduce power factor penalty revenues for customers in the S2 class by approximately 54 percent. Modifying the penalty to apply only to power factor of less than 85 percent, consistent with AE’s former policy on power factor, is estimated to reduce AE’s revenues by approximately $400,000 per year. It should be noted that AE would not recover this lost revenue from other sources. It is important to note that this would not be a change supported by cost of service principles but, rather, it would serve as a policy decision to mitigate bill impacts for certain poor power factor customers. The largest impact of this temporary measure would be experienced by the less than 200 customers that currently experience an increase in their demand charges of 29 percent or greater.

In the long term, AE could consider modifications to the existing rate structure that would limit the amount a low load factor and/or poor power factor customer would pay (on an average rate basis). A limit can be applied to the rate structure without undermining important demand pricing signals embedded in the current rate structure and deviating from cost of service results. Such a limit may result in a subsidy that must be borne by other customers in the class; therefore, the size and breadth of the cap must meet AE policy objectives. This strategy would minimize the amount of subsidy and target the subsidy more directly to low load factor and poor power factor customers. Once such modifications are made, we recommend that the power factor penalty charge for this class of customers be reinstated to the same level as for other AE customer classes (if it was reduced as a short term mitigation measure).

A comprehensive cost of service analysis should be conducted in advance of a long-term strategy so that rate structure modifications properly consider the true cost of serving the lowest load factor customers.

Section 1
INTRODUCTION AND OVERVIEW

Introduction and Overview

At the request of Austin Energy (AE), NewGen Strategies and Solutions (NewGen) has performed a review of AE's retail rate structure applicable to commercial customers with maximum demand in the months June through September of between 10 kilowatts (kW) and less than 50 kW. These customers are served under AE's Secondary Voltage Greater Than or Equal to 10 kW but less than 50 kW (S2) rate schedule. Two separate schedules, with similar rate structures but slightly different rates are applicable to customers inside and outside the Austin City Limits. Hereinafter, within this report, these customers will be refer to as "S2" customers.

On October 1, 2012, AE implemented retail rates as a result of a comprehensive rate study that represented a detailed and in-depth review of AE costs, customer classes, and rate structures (the "2011 Rate Study"). The 2011 Rate Study represented the first time AE had examined its costs in such thorough detail in over 17 years. As a result of this effort, many changes were made to AE customer class designations and rate structures. Some of these changes had significant impact on certain S2 customers' monthly utility bills. To better understand the cause of these impacts and the appropriateness of the current S2 rate design, AE retained NewGen to examine the change in S2 customers' electric bills since the October 1, 2012 implementation of customer classes and rate designs. Specifically, NewGen has performed the following analyses:

1. Examine historical usage characteristics of S2 customers over the period October 2011 through September 2014. Based on this review, determine if the allocation of costs in the 2011 Rate Study was appropriate.
2. Examine historical S2 customer bill impacts with specific attention to the introduction of a demand charge to customers with monthly maximum demands between 10 kW and less than 20 kW. This examination includes a quantitative analysis where historical bills are calculated and evaluated and a qualitative analysis where a sample of commercial customers were interviewed regarding the current rate structure.
3. Compare the S2 rate structure with the rate structure of other utilities in Texas and across the country. Based on this review:
    a. Determine if the application of a demand charge for customers with maximum monthly demands of 10 kW and greater is appropriate.
    b. Determine if the current rate structure and rates are appropriate.

Our analyses are organized within the body of the Report as follows:

- Section 2 – Small Commercial Demand Rate Design History provides a brief summary of the process, goals, and objectives, which led to the current S2 rate design.
- Section 3 – Secondary Service 10 <50 kW Rate Class describes the usage characteristics of customers in this class and the applicable rate.

- Section 4 – Customer Feedback describes information directly received from S2 customers.
- Section 5 – Rate Benchmarking describes the differences between the S2 rate structure and the structures of other utilities serving similarly sized customers.
- Section 6 – Rate Structure Sensitivity examines the impact on existing S2 customers if the current rate structure is changed.
- Section 7 – Recommendations provides NewGen's assessment of the information studied.

Based upon the information gathered in the conduct of the above analyses, NewGen has made conclusions, as described in Sections 3 to 5, and recommendations as described in Section 7 of this report.

Section 2
SMALL COMMERCIAL DEMAND RATE DESIGN HISTORY

History

Prior to October 1, 2012, AE had not increased its base electric rates (which excludes the fuel charge) since 1994. It had become apparent that the prior rate structures had become outdated, as they no longer represented AE's cost structure, no longer considered changes in customer values and perceptions related to electricity consumption and did not reflect AE business goals and objectives. Because of changes in costs, customer values and business objectives, a comprehensive rate review was conducted. Of the many factors considered in the 2011 Rate Study, two fundamental objectives had significant influence on rate design. These two objectives were to improve AE's fixed cost recovery and develop rates with strong pricing signals that supported AE's commitment to energy conservation and renewable energy.

As stated in the 2011 Rate Study Report,

> "AE's electric sales has trended downward from average growth of 6 percent a year between 1994 and 2000 to 1.8 percent from 2001 to 2009. The decline in the annual growth rate is attributed to changing customer demographics, the current economic downturn, and reduced customer consumption due to AE's successful implementation of energy efficiency programs and promotion of conservation, which have helped keep rates stable for the last 17 years. Low load growth is anticipated well into the future. Although load growth is expected to remain low, the costs of operating the utility continue to rise at a steady rate, placing financial stress on the utility.
>
> Additionally, the price of goods and services related to providing electric services has increased since 1994, and the utility has added a number of new business functions and expanded others. While AE customers have experienced the benefits of many new services and programs for several years, the increased costs of these services have been largely unaccounted for in the current rates. New programs and services that have been added, in no particular order or representation of magnitude, include solar rebates, the GreenChoice® renewable energy program, a new unit to coordinate AE generation scheduling activities with the state grid operator, the key accounts function, and a compliance program needed to meet federal grid reliability requirements, among others. AE has expanded its energy efficiency programs, Customer Assistance Program for low-income and other disadvantaged customers, and several programs to build and maintain the smart grid and related communication equipment improving system reliability.
>
> To date, about 800 MW of new electric power generation has been offset through one of the most comprehensive and successful energy efficiency and load shifting programs in the nation. Smart meters have been installed at no direct cost to AE customers, while many electric utilities in Texas have placed a surcharge on customer electric bills to account for these costs. Since AE last set base rates, it has brought online the Sand Hill Energy Center, a 600 MW natural gas-fired facility with highly

efficient combined-cycle units and peaking units to help meet demand during the hot summer months. These new generation resources, which helped meet the utility's energy needs after the Holly Power Plant closure, were funded by AE with no base rate increase."[1]

In short, AE was aggressively promoting programs that sold less energy per customer, yet utility costs per customer continued to rise as a large portion of utility costs are fixed and do not vary with the amount of energy consumed. This phenomenon is not unique to AE, as electric utilities across the country have been faced with a similar circumstance. Customers across the country are increasingly concerned with the environmental impact associated with electricity consumption. This concern, combined with technological advances in end-use products and renewable energy options, have reduced load growth compared to historical levels. In consideration of this change in the electric utility business environment, the 2011 Rate Study proposed rates that improved fixed cost recovery and encouraged conservation.

This rate strategy is confirmed by AE rate design objectives included in the 2011 Rate Study report:

1. Ensure long-term financial strength by setting rates that meet AE's revenue requirement and achieve sustained revenue stability;
2. Improve fixed cost recovery to align AE's rate structure more closely with its cost to serve its customers;
3. Align rates with AE's Strategic Plan by designing rates that encourage efficient energy use and meet changing customer needs by supporting technologies like solar electricity generation and electric vehicles; and
4. Update rates and rate structures to distribute costs fairly among customer classes and encourage efficient energy use.

Rate Design Changes Impacting Small Commercial Customers

Prior to the 2011 Rate Study, most commercial customers qualified for service under one of two classes: a General Service Non-Demand class, which did not include a demand charge and was applicable to commercial customers with maximum monthly demands of less than 20 kW; and a General Service Demand class, which did have a demand charge and was applicable to customers with maximum monthly demands of 20 kW or greater. There was no upper limit on the maximum monthly demand of customers in the General Service Demand class.

As a result of the 2011 Rate Study, commercial rate classes were changed. Most commercial customers qualified for service under one of three following classes.

- Secondary Voltage less than 10 kW (S1), which does not include a demand charge.
- Secondary Voltage greater than 10 kW but less than 50 kW (S2), which does include a demand charge.
- Secondary Voltage greater than or equal to 50 kW (S3), which does include a demand charge.

[1] Austin Energy. (December 19, 2011) Rate Analysis and Recommendation Report. Provided to the Austin City Council. Page 1-4, 1-5.

Changes were made to the commercial customer classes for the following reasons:

1. Customer usage characteristics indicated that customer monthly load factor[2], size (measured in kW) and coincidence with the AE system peak varied significantly at usage levels of less than 10 kW, equal to or greater than 10 kW but less than 50 kW, and 50 kW or more. These changes resulted in cost of service differences between these three groups of customers.
2. Public Utility Commission of Texas (PUCT) regulation of Transmission and Distribution Utilities (TDU) serving the deregulated retail markets in Texas made a rate design distinction at 10 kW, where customers with maximum monthly demand of less than 10 kW did not have demand charges and customers with maximum monthly demands of 10 kW or greater, did have demand charges. Given that AE's rates may be reviewed by the PUCT, commission precedent was an important consideration.
3. Expanding the application of demand charges to smaller commercial customers improved fixed cost recovery and encouraged these customers to reduce demand or improve efficiency as measured by monthly load factor.

As a result of these changes, AE's current rates applicable to most commercial customers are summarized in the following table.

[2] Load factor is defined as average load divided by peak load over a predefined period, and is a measure of efficiency where a higher value (closer to 100 percent) is more efficient.

Table 2-1
AE Current Secondary Voltage Commercial Rates (S1-S3)

Current Commercial Rates (1)	Secondary Service <10 kW (S1)	Secondary Service 10 to <50 kW (S2)	Secondary Service ≥50 kW (S3)
Customer Charge ($/month)	18.00	25.00	65.00
Electric Delivery ($/kW billed)	N/A	4.00	4.50
Demand Charge ($/kW billed)			
Summer (2)	N/A	6.15	7.85
Non-Summer (2)	N/A	5.15	6.85
Energy Charge (¢/kWh)			
Summer	6.198	2.914	2.247
Non-Summer	4.598	2.414	1.747
Pass-Throughs (3)			
Power Supply Adjustment (¢/kWh)	3.709	3.709	3.709
Customer Assistance Program (¢/kWh)	0.065	0.065	0.065
Service Area Street Lighting (¢/kWh)	0.096	0.076	0.068
Energy Efficiency Services (¢/kWh)	0.466	0.522	0.274
Regulatory Charge			
(¢/kWh)	0.859	N/A	N/A
($/kW billed)	N/A	2.56	2.49

Notes:
(1) Rates shown are for Inside City Limits customers.
(2) Summer rates are for June 1 through September 30 and non-summer rates are for October 1 through May 31.
(3) Pass-throughs are effective as of November 1, 2013.

For some small commercial customers, particularly those with demand requirements between 10 kW and 20 kW, the change in customer class designations and rate design may have created large changes in customer monthly bills as these customers migrated from an old rate without a demand charge to a new rate with a demand charge. Customers in this category with low monthly load factors likely experienced large increases in their monthly bills and some customers with high monthly load factors may have experienced a reduction in their monthly bills. If customers with low monthly load factors did not change their usage characteristics as a result of the rate change, higher monthly bills would be expected to persist.

Section 3
SECONDARY SERVICE 10 < 50 KW (S2) RATE CLASS

Introduction

The term Customer Usage Characteristics refers to the way customers use electricity. Important characteristics that influence utility costs include customer delivery voltage (i.e., secondary, primary, or transmission), coincidence with the system peak measured by demand (measured in kW), load factor and to a lesser degree size (measured in kW). Load factor is a measure of efficiency based on the relationship between demand and energy used by a customer. Variations in these characteristics mean that some customers are more or less expensive to serve than others. A cost of service study examines these characteristics by customer class, or groups of customers, and allocates costs to classes based on these characteristics. Once costs are allocated then rates can be designed. To the extent practical, rate design reflects these underlying costs and aligns those costs with common usage characteristics, such as the number of customers, size of demand and energy usage.

During the 2011 Rate Study, AE used detailed load research data to examine and understand these customer usage characteristics for all customer classes. The research data was gathered over the period October 2008 through September 2009 and was normalized for various factors, including weather. The result of the analyses and the corresponding cost of service is summarized in the following table.

Table 3-1
Secondary Voltage Customer Usage and Characteristics

2011 Rate Study Usage Characteristics	Secondary Service <10 kW (S1)	Secondary Service 10 to <50 kW (S2)	Secondary Service ≥50 kW (S3)
Number of Customers	32,001	10,360	3,214
Average Max Demand Per Customer (kW)	3.01	23.83	267.57
Coincidence Factor (Coincident Demand/ Maximum Demand)	88.0%	78.1%	81.9%
Average Monthly Energy Used (kWh)	987	7,939	107,415
Average Monthly Load Factor	44.9%	45.6%	55.0%
Average Cost of Service ($/kWh)	$0.12240	$0.09743	$0.08708
Average Cost of Service as a Percent of Secondary Voltage <10 kW Cost	n/a	79.6%	71.1%

As shown in the above table, variations in usage characteristics between the three commercial secondary voltage customer classes resulted in meaningful differences in cost of service results. On average, the cost of serving S2 and S3 customers is approximately 20 percent to

30 percent less than serving S1 customers. These differentials generally provide cost of service justification for grouping these customer classes as currently defined.

Customer Usage Characteristics

Supplementing load research data used in the 2011 Rate Study, AE provided NewGen with three years of historical data for customers in the S2 class. The data represents actual customer usage over the period October 2011 through September 2014 and has not been weather normalized. The table below compares the customer usage characteristics included in the 2011 Rate Study and the current dataset.

Table 3-2
Customer Usage Characteristics

Class Usage Characteristics	Sample Dataset	2011 Rate Study	Difference
Number of Customers	13,522	10,360	3,162
Average Monthly Demand Per Customer (kW)	20.92	23.83	(2.91)
Average Monthly Energy Per Customer (kWh)	5,292	7,939	(2,647)
Average Monthly Load Factor (%)	34.7	45.6	(10.9)

The above table indicates the S2 class has grown considerably since the 2011 Rate Study. The number of customers within this class has grown by approximately 30 percent. Also, energy usage per customer, average monthly demand per customer, and monthly load factor are lower than indicated in the 2011 Rate Study load research data.

A closer examination of the recent data reveals that S2 average customer peak demands (measured in kW) occurred in the winter months. Non-summer peak demands have grown over the last three years. Conversely, summer peak demands have reduced compared to FY 2012. As a result, there has been an observed shifting of peak from the summer season (June through September) to the non-summer season as shown in the following graph.

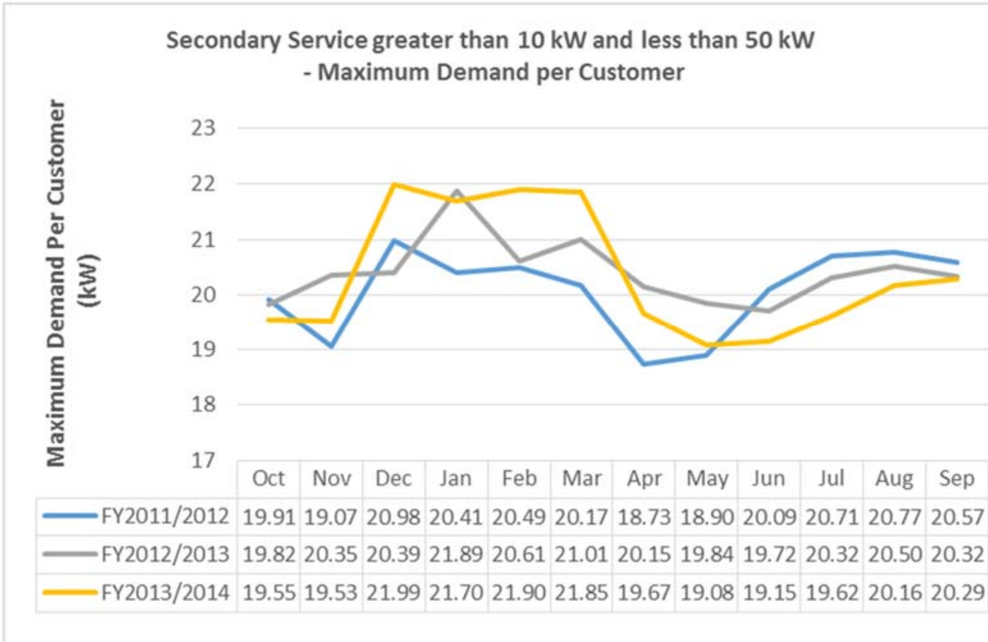
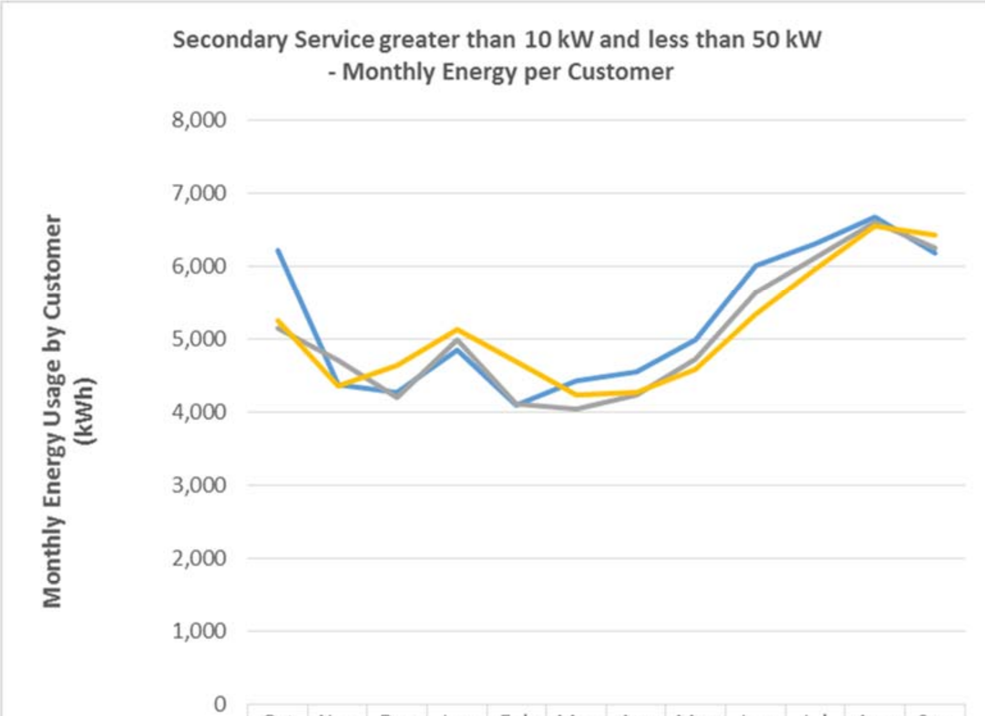


Figure 3-1. Secondary Service Greater Than 10 kW and Less Than 50 kW – Maximum Demand per Customer

The information shown in the above graph reflects actual S2 customer class data and has not been normalized for weather or adjusted for other factors. Given that Texas has experienced relatively similar average temperatures during the summers over this period, one possible explanation for the shifting of demand is customer reaction to the current S2 pricing structure, specifically the summer/non-summer rate differential adopted in the 2011 Rate Study (although this explanation cannot be certain without further study).

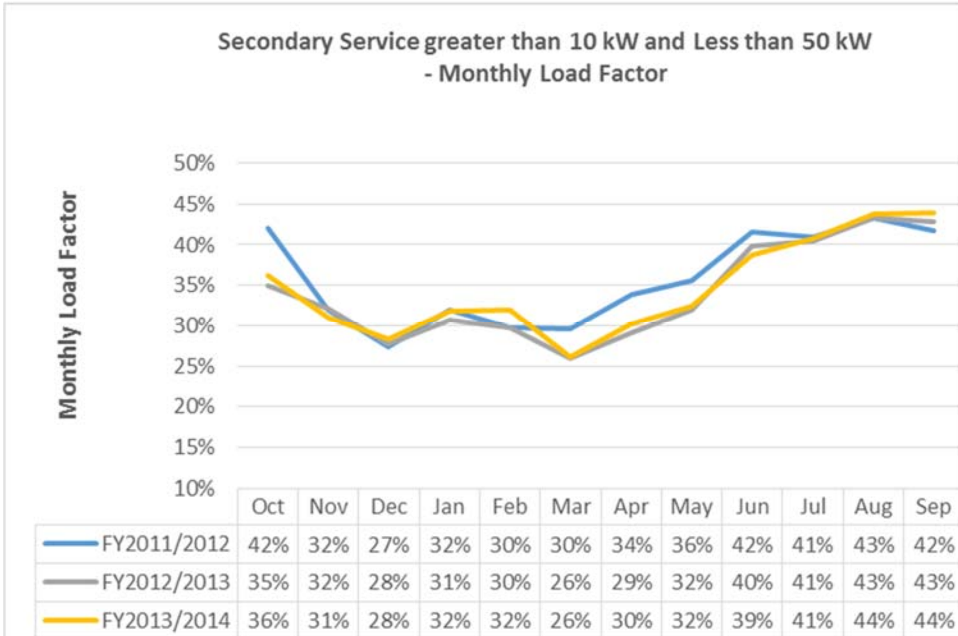
S2 customers' energy use is primarily driven by seasonal variations and ranges between 4,000 kWh and 6,700 kWh per customer for the S2 class. FY 2014 exhibited slightly lower use per customer in the summer months and slightly higher use per customer in the non-summer months as compared with the prior two years. Energy usage per customer is highest during the summer months for the S2 class, and the utility overall, as shown in the following graph.



	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY2011/2012	6,229	4,384	4,279	4,851	4,104	4,430	4,554	5,000	6,019	6,308	6,684	6,187
FY2012/2013	5,156	4,707	4,202	4,997	4,119	4,054	4,234	4,728	5,646	6,122	6,601	6,257
FY2013/2014	5,264	4,364	4,642	5,132	4,701	4,237	4,271	4,597	5,349	5,963	6,565	6,426

Figure 3.2. Secondary Service Greater Than 10 kW and Less Than 50 kW – Monthly Energy per Customer

The shifting demand and energy load patterns appear to be moving together with minimal impact on monthly load factors, which range between 25 percent and 45 percent for the S2 class. Class monthly load factor has not changed meaningfully over the last three years, as evidenced in Figure 3-3 on the following page.



	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY2011/2012	42%	32%	27%	32%	30%	30%	34%	36%	42%	41%	43%	42%
FY2012/2013	35%	32%	28%	31%	30%	26%	29%	32%	40%	41%	43%	43%
FY2013/2014	36%	31%	28%	32%	32%	26%	30%	32%	39%	41%	44%	44%

Figure 3-3. Secondary Service Greater Than 10 kW and Less Than 50 kW – Monthly Load Factor

Based on our review of this historical information, we conclude the following:

- Current class usage characteristics differ from that used in the 2011 Rate Study. It is difficult to predict the impact of these differences on cost of service results as the observed changes have counteracting influences (i.e., some changes tend to increase the cost of service while other changes tend to lower the cost of service). For example, the recent data suggests that the S2 class peak demands occur during the non-summer season. Because this would imply S2 class demands contribute less to the summer system peak than originally thought, cost allocation of peak demands to this class of customers would be lower than originally calculated in the 2011 Rate Study. However, customer monthly load factors are significantly lower (nearly 11 percent lower) as compared to the 2011 Rate Study assumptions. Lower load factors tend to increase the cost of service. Therefore, we can only conclude that customer usage characteristics are different from those used in the 2011 Rate Study and the impacts of these differences on cost of service results is unknown pending an update to the 2011 Rate Study.
- Class peak demands have shifted from the summer season to the non-summer season. This load shift, reducing class contribution to the AE summer system peak, is beneficial to AE's cost structure and was one of the 2011 Rate Study objectives. Underlying causes associated with this shift may be related to changes in customer usage behavior and/or weather. The impact of weather is unknown at this time, as the data have not been weather normalized.
- Observed lower energy and demand use per customer aligns with AE's rate design objectives for this class. These observed changes in electricity consumption may be attributable to customers reacting to the S2 pricing signals, which encourage energy conservation by reducing demand and corresponding energy consumption. Changing customer behavior may also contribute to lower observed monthly load factors.

However, further detailed study is required to fully understand the underlying cause of these observed different usage patterns compared to the load research data used in the 2011 Rate Study.

Power Factor

Power Factor is another measure of efficiency. Power Factor measures the difference between the "total power" that AE must produce to serve customers versus the "real or usable power" observed by a customer. Real power performs work such as running an electric motor or heating an oven. Often, commercial customers operating large motors have poor power factors as the startup and operation of the motors require AE to deliver more "total power" to achieve the customers desired amount of motor performance. The delivery of more electric current results in greater system losses and requires the utility to install additional capacity, at additional cost, throughout the electric system. Therefore, customers with higher power factors have a lower cost to serve, and vice-versa; so, this cost of service difference is commonly reflected in commercial rate structures. A power factor penalty is a charge that compensates AE for the added capacity and energy needed to meet the power requirements of poor power factor customers. From a cost of service perspective, power factor penalty charges are an equitable means of recovering costs directly from customers adding costs to the system.

AE applies a power factor penalty to all demand customers with power factors less than 90 percent, as measured by AE's metering devices. Of the 13,522 customers in the S2 class, approximately 3,452 customers have been assessed a power factor penalty charge at an annual cost of approximately $750,000 to these customers. The class average power factor is 92.6 percent, which is above the penalty threshold. The application of the power factor penalty charge is such that billed demand is adjusted upward when power factor is below the minimum required level of 90 percent. The farther a customer's power factor is below 90 percent, the larger the upward adjustment of billed demand.[3]

The following statistics summarize the estimated impact on customers in the S2 class assessed the power factor penalty.

- Approximately 0.25 percent (or 34 customers) experience an increase in their billing demand and corresponding charges of at least 100 percent.

[3] For example, if a commercial customer inside the City Limits were on the S2 rate with 3,000 kWh and metered demand of 15 kW in June 2014, then their total electric bill would have been $434.23 if they achieved 90% power factor (or better). This would be calculated as a $25 customer charge plus $12.71 per kW in demand charges plus $0.07286 per kWh in energy charges ($25 + $12.71 x 15 kW + $0.07286 x 3,000 kWh). However, if the customer only achieved 80% power factor, then the demand charge would have been increased. The demand component of the bill would have changed from being based on the metered demand of 15 kW to an adjusted (or billed) demand of 16.875 kW. The formula for this adjustment is billed demand equals metered demand times power factor requirement divided by power factor achieved. Or, in this example, billed demand = 15 kW x 0.90 / 0.80. The total electric bill based on 80% power factor would have been $458.06, calculated as $25 + $12.71 x 16.875 kW + $0.07286 x 3,000 kWh. This represents an increase of $23.83 in the demand charge as well as the total bill. This is a 12.5% increase in the demand charge alone or a 5.5% increase in the total bill.

- Approximately 0.24 percent (or 33 customers) experience an increase in their billing demand and corresponding charges of between 50 percent to 80 percent.
- Approximately 0.92 percent (or 124 customers) experience an increase in their billing demand and corresponding charges of between 29 percent to 50 percent.
- Approximately 3.8 percent (or 512 customers) experience an increase in their billing demand and corresponding charges of between 13 percent to 29 percent.
- Approximately 20.3 percent (or 2,749 customers) experience an increase in their billing demand and corresponding charges of between 0 percent to 13 percent.
- Approximately 74.5 percent (or 10,070 customers) experience no increase in their billing demand and corresponding charges as a result of the power factor penalty.

NewGen estimates that completely eliminating the power factor penalty for the S2 class is estimated to reduce AE's revenues by approximately $750,000 per year. This represents less than 1 percent of the class revenue but, for some customers in the S2 class that are subject to the penalty, this may represent a significant portion of their bill. Modifying the penalty to apply only to power factor of less than 85 percent, consistent with AE's former policy on power factor, is estimated to reduce AE's revenues by approximately $400,000 per year. Also, it is important to note that S2 customers with demands greater than or equal to 20 kW have been subject to power factor penalty charges for many years. These customers account for $540,000 or approximately 72 percent of the annual power factor penalty charges.

The table below lists the power factor requirements for various other utilities included in our benchmarking analyses as described in Section 5 of the Report. As indicated, AE's current policy is more lenient than almost all utilities listed in the table (only CPS Energy has a lower requirement).

Table 3-3
Power Factor Benchmarking

Utility	State	Ownership Structure	Power Factor Adjustment
Austin Energy	Texas	Municipal	<90%
Bluebonnet Electric Cooperative	Texas	Distribution Cooperative	<97%
CPS Energy	Texas	Municipal	<85%
Fort Collins Utilities	Colorado	Municipal	<90%
Los Angeles Power and Light	California	Municipal	<95%
Pedernales Electric Cooperative	Texas	Distribution Cooperative	<97%
Reliant/CenterPoint	Texas	Investor Owned Utility	<95%
Sacramento Municipal Utility District	California	Municipal	<95%
TXU-Oncor	Texas	Investor Owned Utility	<95%

Current Rate Design

The current S2 rate contains fixed monthly, demand and energy charges. These rate components ensure that the cost of service is recovered by rates that reflect the cost drivers. For example, metering costs, which are a fixed monthly cost incurred for each customer, regardless of demand placed on the system by the customer or energy used during the billing period, are recovered through a fixed monthly cost. AE has developed the current S2 rate structure based on the 2011 cost of service study, to ensure there is proper cost causation in the rate structure, leading to more efficient use of the system by customers. The current AE S2 rate structure for inside the City Limits is as follows:

Table 3-4
AE Current Secondary Voltage Commercial Rates (S2)

Current Commercial Rates (1)	Secondary Service 10 to <50 kW (S2)
Customer Charge ($/month)	25.00
Electric Delivery ($/kW billed)	4.00
Demand Charge ($/kW billed)	
Summer (2)	6.15
Non-Summer (2)	5.15
Energy Charge (¢/kWh)	
Summer	2.914
Non-Summer	2.414
Pass-Throughs (3)	
Power Supply Adjustment (¢/kWh)	3.709
Customer Assistance Program (¢/kWh)	0.065
Service Area Street Lighting (¢/kWh)	0.076
Energy Efficiency Services (¢/kWh)	0.522
Regulatory Charge	
(¢/kWh)	N/A
($/kW billed)	2.56

Notes:
(1) Rates shown are for Inside City Limits customers.
(2) Summer rates are for June 1 through September 30 and non-summer rates are for October 1 through May 31.
(3) Pass-throughs are effective as of November 1, 2013.

We can present the S2 rate graphically by comparing the change in the average rate over changing customer usage patterns. Rate structures with demand and energy components, like the S2 rate, recognize and incentivize customers to improve their monthly load factors. Monthly load factor is one of the most important factors in determining cost of service. In recognition of the relationship between monthly load factor and average rates, we have developed graphs presented within this report that demonstrate this relationship. Information on each graph is a follows:

- **Average Rate Compared to Average Monthly Load Factor.** The Primary Y-axis indicates the average rate a customer would pay under the identified rate(s). The X-axis indicates the varying monthly load factor of a customer.
- **Number of Customer Bills in the Class.** The Secondary Y-axis indicates the number of customer bills at a given monthly load factor which are illustrated in a bar graph. Information on the distribution of customer monthly load factors provides valuable insight as to the impact and importance of the identified rate(s) on the overall class.

The following graph shows the impact of the S2 rate structure on customers within the class.

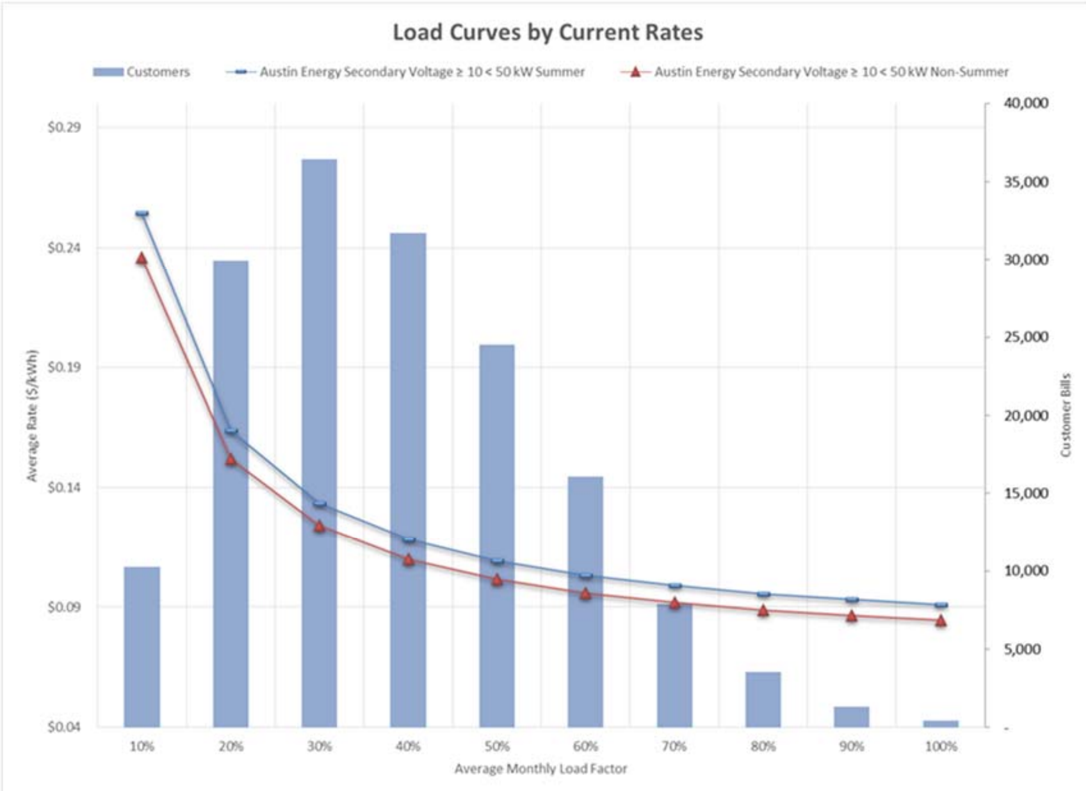


Figure 3-4. Load Curves by Current Rates

The existing rate structure rewards high load factor customers with a lower average rate. For example, customers with a 30 percent load factor have an average rate that is nearly $0.10 per kWh lower than customers with a 10 percent load factor. This result is consistent with cost of service results and reflects that high load factor customers use more energy per kW of demand than low load factor customers. Therefore, high load factor customers can spread the fixed costs associated with meeting their demand over more units of energy (kWhs), thereby lowering their average rate (in $ per kWh).

S2 Class Revenue Requirement

NewGen developed a revenue requirement for the S2 customer class utilizing historical, three-year average billing units applied to the S2 rate with current pass-through adjustments. Developing a revenue requirement for the S2 class is an important step in analyzing the rate structure of the S2 class. Any sensitivity analysis on rate structure and rate benchmarking in this report presents rate structures that generate the same amount of revenue as the current S2 rates. The S2 revenue requirement calculation is shown in the table below.

Table 3-5
AE Proof of Revenue Under Current Rates

	Inside City Limits (ICL)			Outside City Limits (OCL)			Total
Rate Schedule	Billing Units	Rate	Revenue	Billing Units	Rate	Revenue	Revenue
Customer Charge	**138,187**	**$25.00**	**$3,454,675**	**24,077**	**$25.00**	**$601,925**	**$4,056,600**
Demand Charges							
Summer(1) ($/kW-billed)	1,012,365	$6.15	$6,226,042	164,792	$6.11	$1,006,881	$7,232,923
Non-Summer(1) ($/kW-billed)	1,877,111	$5.15	9,667,124	339,867	$5.12	1,740,119	11,407,243
Subtotal Demand Charges			**$15,893,166**			**$2,747,000**	**$18,640,166**
Electric Delivery ($/kW-billed)	2,889,476	$4.00	$11,557,904	504,659	$3.98	$2,008,544	$13,566,448
Regulatory Charge ($/kW)	2,889,476	$2.56	7,397,059	504,659	$2.56	1,291,928	8,688,986
Subtotal Demand Charges and Adjustment Charges			**$34,848,129**			**$6,113,077**	**$40,961,206**
Energy Charge (¢/kWh)							
Summer Energy(1) (¢/kWh)	307,959,288	$0.02914	$8,973,934	46,783,352	$0.02896	$1,354,846	$10,328,780
Non-Summer Energy(1) (¢/kWh)	433,209,672	$0.02414	10,457,681	70,674,283	$0.02399	1,695,476	12,153,158
Subtotal Energy Charge			**$19,431,615**			**$3,050,322**	**$22,481,937**
Power Supply Adjustment(2) ($/kWh)	741,168,960	$0.03709	$27,489,957	117,457,635	$0.03709	$4,356,504	$31,846,460
Customer Assistance Program(2) ($/kWh)	741,168,960	$0.00065	481,760	117,457,635	$0.00065	76,347	558,107
Service Area Street Lighting(2) ($/kWh)	741,168,960	$0.00076	563,288	117,457,635	$-	-	563,288
Energy Efficiency Services(2) ($/kWh)	741,168,960	$0.00522	3,868,902	117,457,635	$0.00522	613,129	4,482,031
Subtotal Energy Charge and Adjustment Charges			**$51,835,522**			**$8,096,302**	**$59,931,824**
Total Revenue			**$90,138,326**			**$14,811,304**	**$104,949,630**

Notes:
(1) Summer rates are for June 1 through September 30 and non-summer rates are for October 1 through May 31.
(2) Pass-throughs are effective as of November 1, 2013.

As shown above, the S2 customer class generates $104,949,630 in annual revenue.

Conclusions

Based on our review of the 2011 Rate Study and current customer usage characteristics of S2 customers, we conclude the following:

- Load research data used in the 2011 Rate Study yielded meaningful differences in cost of service results for S1, S2, and S3 customers. These differences support three different rate classes.
- For the period October 2011 through September 2014, customer usage characteristics for S2 customers differ from the class usage characteristics used in the 2011 Rate Study. Differences pertain to customer size (as measured in kW), monthly energy usage, monthly load factor, and seasonality of load. Because these differences do not impact cost allocation in a uniform manner, the impact of these differences on cost of service results pertaining to the S2 class are unknown.
- Over the three-year period studied, S2 customer summer demands have been lower while non-summer demands have increased. Loads have shifted from on-peak summer months to off-peak non-summer months, consistent with the pricing incentives embedded in AE's rate design.
- Over the three-year period studied, energy consumption has not materially increased and in many months has declined. Monthly load factor, which is a measure of the relationship between customer demand and energy use, has remained relatively steady over the period evaluated.
- Weather during the three summers (2012-1014) included in the period evaluated was relatively similar and on average cooler when compared to the record hot summers observed in 2011 and earlier. Recognizing that weather is an important factor influencing consumption of electricity, and the weather was less extreme over this three year period, it appears that the pricing signals associated with the S2 rate are accomplishing AE's rate design objectives as established in the 2011 Rate Study. AE's S2 rate structure appears to be lowering the class contribution to on-peak demand, promoting conservation and efficiency and improving AE's fixed cost recovery. This conclusion is subject to further study and verification pending the completion of a detailed load normalization study.
- Cost of service principles dictate that customer monthly load factor, rather than size (as measured in kW), is a primary indicator of average cost. Approximately, 47 percent of S2 customers have average monthly load factors of 30 percent or less. One-third of these low load factor customers have maximum demands between 20 kW and 50 kW and two-thirds have maximum demands between 10 kW and 20 kW in the months of June through September.
- Power factor penalty charges are uniformly applied throughout the industry to recover the added cost associated with serving customers with electric motors or other loads that reduce the efficient delivery of real power to customers. These penalties are often assessed via the demand charge.
- AE's current power factor penalty threshold of 90 percent is reasonable compared to its peers in the industry.

- From a cost of service perspective, power factor penalty charges are an equitable means of recovering costs directly from customers adding costs to the system.
- Power factor penalty charges generate approximately $750,000 annually for the S2 class, or approximately 0.7 percent of annual class revenues. The cost is borne by approximately 3,500 customers in the S2 class.
- Prior to the creation of the S2 class, approximately 20 percent of the S2 customers currently paying power factor penalty charges were in a non-demand rate class and, therefore, were not subject to power factor penalty charges. These customers experienced greater bill impacts as they were introduced to a demand charge and a power factor penalty charge simultaneously when the S2 class was formed.
- The S2 customer class is projected to generate approximately $105 million in revenue annually under the current rates.
- AE’s S2 rate structure is in alignment with cost of service results and principles – high load factor customers have a lower average rate than low load factor customers.

Section 4
CUSTOMER FEEDBACK

NewGen endeavored to obtain customer feedback on the rates resulting from the 2011 Rate Study. Some of the feedback received was positive and some was negative. One source of feedback was via a focus group conducted by Creative Consumer Research and the other was from NewGen contacting individual customers that had contacted Austin City Council members regarding their rates. It is difficult to draw concrete conclusions regarding the sentiment of the overall customer class from these small samples, but these results add some context to the rate discussion.

Focus Group

AE contracted with Creative Consumer Research to develop and facilitate a focus group comprised of customers in the S2 customer class. The customers participating in the focus group included one (1) customer that currently has a 10 kW to 20 kW load and six (6) customers that currently have 20 kW to 50 kW loads. The focus group interaction occurred on February 12, 2015 and represented a range of user types, including a retail shop, a gymnasium, apartment management, an ice cream shop, and a construction services company.

The seven participants were selected from a pool of 158 commercial customers whose energy usage fell within the 10 kW to 20 kW or 20 kW to 50 kW ranges. The 158 customers were selected to represent a range of load factors, a diversity of business types, and representation for locally-owned businesses. As reported by Creative Consumer Research, all 158 potential participants were contacted; however, several declined participation because they did not believe they were significantly impacted by the rate change implemented by AE on October 1, 2012. Further, the majority of the participants in the focus group reported that they were not adversely affected by the new rate structure.

When given a written description of the rate structure for the S2 class, the participants generally reacted positively indicating that customers whose energy use had an impact on the system should pay more to reflect that impact. A few participants did indicate that a higher energy bill would cause them to consider making adjustments in their use of power (either through changes in behavior or energy savings investments) in an effort to reduce their bills. The participants agreed that anything that causes them to pay higher energy bills could be bad for their bottom line, but most participants reported that their energy costs amounted to a small part of their overall business expense and several indicated they would simply pass along the cost to their customers. Most of the participants had completed some type of energy efficiency improvement to their business or implemented an energy saving policy (e.g., installing programmable thermostats, installing energy efficient lighting, or creating policies to minimize energy usage).

Most, if not all, of the participants gave AE high ratings for customer satisfaction despite the fact that several of them had experienced some issues with AE in the recent past (e.g., incorrect utility bills, failing to receive their utility bill, and general frustration with the customer service they received via the call center).

In general, NewGen's assessment of the focus group is that the customers are reacting to the rate structure for the S2 class in a manner that is consistent with the design of the rate structure. The rate structure was intended to send a pricing signal to users of the electric utility to encourage conservation, energy efficiency investments, peak shaving, and other changes in customer behavior that align with AE's strategic objectives. Based on the responses from the focus group, this seems to be the response the rate design has engendered.

Select Customers

NewGen attempted to contact six (6) customers in the S2 class that had contacted Austin City Council members regarding their rates. NewGen spoke with two (2) of these customers and their comments are summarized below.

Temporary S2 Customer

One of the customers that had contacted Austin City Council was assigned to the S2 class for a short period of time. This is a customer that typically has demands less than 10 kW but an event beyond his control caused his demand to spike beyond 10 kW in June, which caused his business to be moved to the S2 rate and incur demand charges. The event that caused the spike in demand was apparently related to some work a contractor was doing on the roof of his building.

The customer's first indication that his rate had changed was when he received a letter from AE discussing retroactive billing, which he did not understand. When his bill arrived, it reflected significant charges resulting not only from the move to a demand rate (i.e., the S2 rate), but also the impact of the retroactive billing issue. He contacted AE to dispute the charges and, eventually, identified the cause of the spike in demand. He also contacted Austin City Council to help address his issue as he did not feel he was getting appropriate redress from AE. He indicated AE eventually resolved the issue to his satisfaction by removing the demand charges. Also, since his demand subsequent to the spike has been below 10 kW, he is now back in the S1 class.

He characterized the event in retrospect as "no big deal" but did indicate that AE made it harder than it needed to be in order to resolve the issue. The issue could have been addressed, in his view, without as much effort on his part to identify and correct the problem. He did acknowledge that, at the time, AE was being inundated with calls due to the retroactive billing issue.

Dissatisfied S2 Customer

One of the other customers that contacted Austin City Council exhibits demands in the June through September billing months that routinely place his business in the S2 class. His demands during these four months in the last three years have averaged approximately 16 kW. Thus, his business was categorized as General Service Non-Demand (or E02) under the rate classes as they existed prior to the October 1, 2012 rate adjustments. As a result, this customer transitioned from a $6.00 per month customer charge plus energy charges to the S2 rate structure, which includes demand charges.

This business operates three-phase equipment, typically three days per week. The building the business leases for operations has electric heat, as there is no natural gas service to the property. This results in a fairly significant heating load, which drives electric demands higher in the winter. In fact, the greatest demand for this customer in each of the last three years has occurred in January of each year. The average demand in the last three Januarys has been approximately 33 kW. The customer self-reported that his electric bill for January 2015 was approximately $750 and this is consistent with the bills received in January 2013 and 2014 (all subsequent to the October 1, 2012 rate adjustments). If on-site propane heat is an option for this customer, it could potentially reduce the electric bill significantly.

The load factor for this customer is at the lower end of the possible range. This customer's average monthly load factor over the past three years is approximately 16 percent with a maximum of approximately 26 percent and a minimum of approximately 7 percent. This has significant implications for the cost of providing service to this customer and, as a result, bills under the S2 rates. Previously, under the E02 rate, this customer's poor load factor was subsidized by the other (more efficient) customers in the class. However, under the S2 rate the costs associated with poor load factor are directly billed to the customer.

In addition to the transition to a rate with demand charges, and low load factor, this customer's bills are also impacted by AE's 90 percent power factor requirement (which is only applicable to customers with demand charges). This customer's energy use exhibits power factor of less than the 90 percent requirement roughly half of the months of the year, likely due to the three-phase equipment used in the business operation. The power factor for this customer has been as low as approximately 85 percent in at least one month of each of the last three years. Power factor of less than 90 percent results in greater demand charges. It is possible that capacitors, or some other change in operation or investment, could bring this customer's power factor up to at least 90 percent and eliminate the penalty associated with this issue.

Energy is one of the key costs in this business, according to the customer. His business has seven (7) employees and well under $1 million in gross revenue annually. The customer observed that his is a small, local business and that these types of businesses are critical to the local and broader economy. As proof of this claim, the customer cited multiple statistics regarding the importance of small business, including some that can be found at the United States (U.S.) Small Business Administration's website.[4]

This customer has not made any changes recently, but has made efforts in the past to make changes to the building (e.g., lighting replacement) and operations in order to conserve energy and lessen his demands. Since he does not own the building, additional changes to the building (e.g., insulation) are difficult. The owner of the building does not want to pay for the investment since he does not receive the financial benefit (as the building owner does not pay the utility bills) and the business does not want to invest in improvement to a building it does not own. Thus, the most practical changes to improve energy efficiency for this customer might be tied directly to operations or subsidized investments.

This customer expressed extreme frustration and dissatisfaction with AE. He sincerely feels that AE is not concerned with his problems. In NewGen's opinion, this represents a failure on the part of AE as well as an opportunity for AE to improve its relationship with this customer. There are likely operational changes or investments that could be made to improve this customer's load and, by extension, lower his bills. Some of these opportunities might include options that have been mentioned here (e.g., on-site propane heat, capacitors, operational

[4] https://www.sba.gov/sites/default/files/FAQ_Sept_2012.pdf

changes), but a comprehensive energy audit should identify the most appropriate and cost-effective changes for this customer's particular circumstances.

Best of all, the customer reacted positively to the prospect of having an energy audit conducted. NewGen is not aware if this option has been presented to this customer in the past, but this might be the perfect means for AE to assist this customer and improve its relationship with one of its small business customers.

Conclusions

Based on our observations of S2 customer feedback as conducted by Creative Consumer Research and direct phone conversations with two customers who have expressed concern over the S2 rate to the City Council, we conclude the following:

- Overall, at the class level, there appears to be limited concern over the impact of the S2 rate on customer finances. This is evidenced by the general difficulty in getting customers to attend a customer feedback discussion on this issue.
- Customers who did participate in the feedback session did indicate that some customers are reacting to the S2 pricing signals by considering investments in energy efficiency or changes in energy use. The focus group conducted by Creative Consumer Research indicated most customers are supportive of the goals of the demand rate structure, recognizing that customer costs increase and decrease with changes in monthly load factor. These responses are in alignment with AE's 2011 Rate Study objectives.
- Concern over the S2 rate structure and the impact on customer bills appears to be limited to a small group of customers with low load factors and poor power factors.
- One customer that contacted Austin City Council felt the rate being charged to him was unduly burdensome. The customer's monthly power bill has increased dramatically under the S2 rate structure as this customer's usage characteristics resulted in maximum demands of 33 kW (in the winter), low monthly load factors, and poor power factor as the business operation requires use of a significant amount of motors.

Section 5
RATE BENCHMARKING

Introduction

The objective of this benchmarking analysis is to compare AE's S2 rate structure with the rate structures of other utilities. The term rate structure refers to the design and components of the rate. For example, commercial rate components may include a customer charge, demand charges, and energy charges. Rates associated with each component may vary by season or time of day. Rate structures have a significant impact on customer bills within a class. A simple energy-only rate structure tends to minimize variations in effective rates paid by customers within a class, even if they exhibit very different usage characteristics. Conversely, a demand/energy rate structure will recognize these variations in usage characteristics creating a greater variation in effective rates for customers in the same rate class.

This benchmarking process differs from a traditional rate comparison analysis in that the benchmarking as described herein analyzes the differences in utility rate structures, not utility costs. In a traditional rate comparison analysis with two utilities having identical rate structures, but different cost structures, the utility with lower costs would result in customers having a lower monthly bill. However, in this rate structure benchmarking analysis, utility cost differentials are eliminated, so comparing two utilities having identical rate structures would result in customers having identical bills.

To remove cost differentials from this rate structure benchmarking analysis, we have adjusted comparison utility rates either upward or downward on a prorata basis so that total rate revenues from the comparison utility are equal to rate revenue generated from AE's current S2 rate. This ensures the benchmarking analysis is isolated to a comparison of rate structures, rather than reflecting the differences in the costs to provide service.

Comparable Utilities

For the rate structure benchmarking analysis, we have selected eight (8) comparable utilities that exhibit some or all of the following criteria:

1. Municipal or consumer-owned utilities in the surrounding AE service territory.
2. Retail Electric Providers (REP) operating within competitive areas of the Electric Reliability Council of Texas (ERCOT).
3. Large public power utilities.
4. Municipal utilities with a strong commitment to energy conservation and renewable energy.

Based on these criteria, the utilities listed in Table 5-1 were selected for an in-depth review.

Table 5-1
Compatible Utilities Benchmarked

Utility	State	Ownership Structure	Large Public Power Member	Commitment to Conservation	Commitment to Renewables
Bluebonnet Electric Cooperative	Texas	Distribution Cooperative	N/A	Neutral	Neutral
CPS Energy	Texas	Municipal	Yes	Strong	Strong
Fort Collins Utilities	Colorado	Municipal	No	Strong	Strong
Los Angeles Power and Light	California	Municipal	Yes	Strong	Strong
Pedernales Electric Cooperative	Texas	Distribution Cooperative	N/A	Neutral	Neutral
Reliant/CenterPoint	Texas	Investor Owned Utility	N/A	Neutral	Neutral
Sacramento Municipal Utility District	California	Municipal	Yes	Strong	Strong
TXU-Oncor	Texas	Investor Owned Utility	N/A	Neutral	Neutral

In the above Table, Reliant/CenterPoint and TXU/Oncor are two retail electric providers (REPs) identified in the benchmarking analyses. REPs operate throughout the ERCOT competitive retail market. The designation Reliant/CenterPoint means that Reliant is the REP and is the customer service interface with the customer. Reliant bundles power supply and delivery charges provided by others in the offer of electric service to retail customers. CenterPoint is the Transmission and Distribution Utility (TDU). A TDU serves a specific geographic area and is regulated by the PUCT. As a TDU, CenterPoint provides the wires through which Reliant delivers power to its retail customers. TDU rates change in different geographic areas. Because Reliant bundles power supply and TDU charges, the TDU rate structure influences the retail rates charged by Reliant. Therefore, Reliant/CenterPoint is a unique retail rate offering available to customers physically connected to the CenterPoint TDU. This rate is different than a Reliant-AEP Texas North rate, Reliant-Sharyland rate or any other combination of the six TDU's that Reliant uses to delivery power to customers. Also, REPs can offer multiple rate packages for different service, utilizing different rate structures, to commercial customers. The REP's retail rate can align with the pricing structure from the TDU, or utilize a structure that deviates from the TDU rate structure.

As mentioned in Section 2, the TDU's are subject to PUCT regulation and predominately implement demand charge at 10 kW and greater. This PUCT policy is reflected in the rates set by Reliant/CenterPoint and TXU/Oncor, as listed in Table 5-2.

Commercial Classes

The criteria applied in the development of rate classes varies widely between utilities. For commercial customers, rate classes are typically defined by customer size, as measured by the customer's peak demand. As described in Section 2 of this report, AE serves the majority of its commercial secondary voltage customers with three rate classes defined by size of demand. Class size delineations are set at less than 10 kW, 10 kW and greater but less than 50 kW, and 50 kW and greater. To ensure a valid comparison of rate structures, benchmark utility customer class criteria were compared to AE's criteria so that the rate structures examined were applicable to AE customers receiving service under the S2 rate. The alignment of benchmarked utilities' commercial rate criteria with AE's S2 class is shown in Table 5-2.

Table 5-2
Applicable Rate Schedules By Customer Size

Utility	Customer Size 0-9.9 kW	Customer Size 10 kW – 49.9 kW	Customer Size >50 kW
Austin Energy	Secondary Service < 10 kW (S1)	Secondary Service 10 kW – 49.9 kW (S2)	Secondary Service >50 kW (S3)
Bluebonnet Electric Cooperative	Basic <50kW	Basic<50kW	Large Power < 250 kW
CPS Energy	General Service (PL)(1)	General Service (PL)(1)	General Service (PL)(1)
Fort Collins Utilities	General Service <25 kW	General Service <25 kW General Service 25 kW to less than 50 kW	General Service 50 kW to less than 750 kW
Los Angeles Power and Light	Small General Service <30kW	Small General Service <30 kW Primary Service 30 kW or greater	Primary Service 30 kW or greater
Pedernales Electric Cooperative	Small Power <75kW	Small Power <75 kW	Small Power < 75 kW
Reliant/CenterPoint	Reliant Rockets Secure Advantage 12 Plan CenterPoint – TDU <10 kW	Reliant Rockets Secure Advantage 12 Plan CenterPoint – TDU >10 kW	Reliant Rockets Secure Advantage 12 Plan CenterPoint – TDU >10 kW
Sacramento Municipal Utility District	Small General Service Non-Demand <20 kW	Small General Service Non-Demand <20 kW Small General Service Demand >20 kW but less the 299 kW	Small General Service Demand >20 kW but less the 299 kW
TXU/Oncor	TXU Energy Business Monthly Saver 36 Oncor – TDU <10 kW	TXU Energy Business Monthly Saver 36 Oncor – TDU -10 kW	TXU Energy Business Monthly Saver 36 Oncor – TDU >10 kW

Notes:
(1) CPS Energy simultaneously offers its commercial customers service under General Service (PL) and Large Light and Power (LLP). The customer can pick the most appropriate tariff for their situation. For the purposes of this benchmarking review, we have compared AE's Secondary Service 10kW – 49.9 kW rate with CPS Energy's General Service (PL) rate.

For the purposes of the benchmarking analysis, rates in the green highlighted column of the table above (10 kW to 49.9 kW) were studied.

Small Commercial Customer Class Designations

Across the industry, commercial customer class qualification criteria is associated with customer metering capabilities, customer size and delivery voltage. Before Advanced Metering Infrastructure (AMI) meters, also known as "smart meters," only larger commercial customers were demand metered, as the cost of these meters was significant compared with energy-only rate alternatives. Now, with AMI meters becoming more affordable, the cost and capability of the meter is similar for all customers (e.g., residential, commercial, etc.), so it is now more practical to measure demand for all customers. As a result of this technological advancement, class designations such as "Commercial Non-Demand" and "Commercial Demand" based on metering limitations, or meter cost, are becoming less relevant. However, these legacy class designations remain common in the industry. Beyond initial “non-demand” and “demand” class descriptions, other class designations based on size (kW) vary greatly among utilities. Additionally, common class designations are based on delivery service voltage such as secondary, primary, and transmission. Delivery voltage is an important cost of service differentiator in a rate study.

The following table summarizes class boundaries between small commercial customers for each of the benchmarked utilities. Changes in shading reflect a change in rate structure or class. Boundaries reflect the point where the rate or rate structure changes as customer size changes.

Table 5-3
Small Commercial Customer Class Boundaries

Customer Demand										
Minimum Demand (kW)	**0**	**10**	**15**	**20**	**25**	**30**	**35**	**40**	**45**	**50**
Maximum Demand (kW)	**10**	**15**	**20**	**25**	**30**	**35**	**40**	**45**	**50**	**+**
Utility										
Austin Energy										
Bluebonnet Electric Cooperative										
CPS Energy										
Fort Collins Utilities										
Los Angeles Department of Power and Light										
Perdenales Electric Cooperative										
Reliant-CenterPoint										
Sacramento Municipal District										
TXU/Oncor										

This small commercial rate comparison indicates that AE, Reliant/CenterPoint, and TXU/Oncor have 10 kW boundaries. The Reliant/CenterPoint and TXU/Oncor boundaries are dictated by PUCT class requirements for TDUs. Both Reliant and TXU pass through their TDU charges to retail customers. Reliant modifies the CenterPoint TDU cost, but TXU passes through Oncor TDU’s as incurred. Per PUCT requirements, TDU’s serve secondary service less than 10 kW customers with a rate structure consisting of a customer and an energy charge. For customers with demands greater than 10 kW, TDU’s rate structures include a customer, demand and energy charge. Because of the change in rate structure, we conclude the REPs rate structures, with TDU pass through provisions, change at 10 kW.

For non-REP utilities in the benchmarking survey, class boundaries vary from 20 kW to upwards of 700 kW. Five (5) non-REP utilities have boundaries ranging from 20 kW to 75 kW. Two non-REP utilities have very large boundaries at 200 kW to 750 kW. Utilities with large variations in size within the class typically use demand charges to track costs and minimize subsidization.

Rate Structure Review

This section of the report provides a detailed comparison of each utility's rate structure with AE's S2 class.

Bluebonnet Electric Cooperative

Bluebonnet Electric Cooperative (BEC) is a consumer owned distribution cooperative serving customers bordering AE's service territory. BEC is a wholesale customer of the Lower Colorado River Authority (LCRA). The LCRA's wholesale power costs are billed to BEC on an energy-only basis; therefore, the majority of BEC's fixed costs are related to its distribution system.

The applicable BEC rate for the rate structure review is the Basic Rate. The Basic Rate is available to all commercial and industrial customers and other consumers whose peak demand is consistently less than 50kW per billing cycle. A summary of the Basic Rate compared to AE's S2 rate is shown in the following table.

Table 5-4
AE and BEC Rate Comparison

Rate Structure Comparison	AE's Secondary Voltage 10kW to 50kW (S2)	BEC's Basic <50kW	BEC's Basic <50kW (Adjusted)
Customer Charge ($/month) (1)	25.00	50.00	54.64
Electric Delivery ($/kW billed)	4.00	N/A	N/A
Demand Charge ($/kW billed)			
Summer	6.15	N/A	N/A
Non-Summer	5.15	N/A	N/A
Energy Charge (¢/kWh)			
Summer	2.914	6.457	7.056
Non-Summer	2.414	6.457	7.056
Pass-Throughs (¢/kWh)			
Power Supply Adjustment	3.709	0.109	0.109
Customer Assistance Program	0.065	N/A	N/A
Service Area Street Lighting	0.076	N/A	N/A
Energy Efficiency Services	0.522	N/A	N/A
Distribution Charge (1)	N/A	3.684	4.026
Regulatory Charge			
(¢/kWh)	N/A	N/A	N/A
($/kW billed)	2.56	N/A	N/A

Notes:
(1) Assumed three-phase customer

BEC's Basic rate does not include a demand charge.

The adjusted BEC rate as shown in the above table reflects a prorata adjustment of the rate so that the BEC rate applied to AE customers served under the S2 rate would generate an equal amount of revenue. In other words, AE would be financially indifferent to either rate as both rates generated the same amount of revenue (although the BEC rate would not necessarily support the City of Austin's goals and objectives). The analysis supporting this revenue neutral calculation is shown in Exhibit 1 of this report.

Graphical comparisons of BEC's Basic Rate compared to AE's S2 rate for customers with monthly maximum demands of 15kW, 25kW, and 45kW are shown in the following graphs.

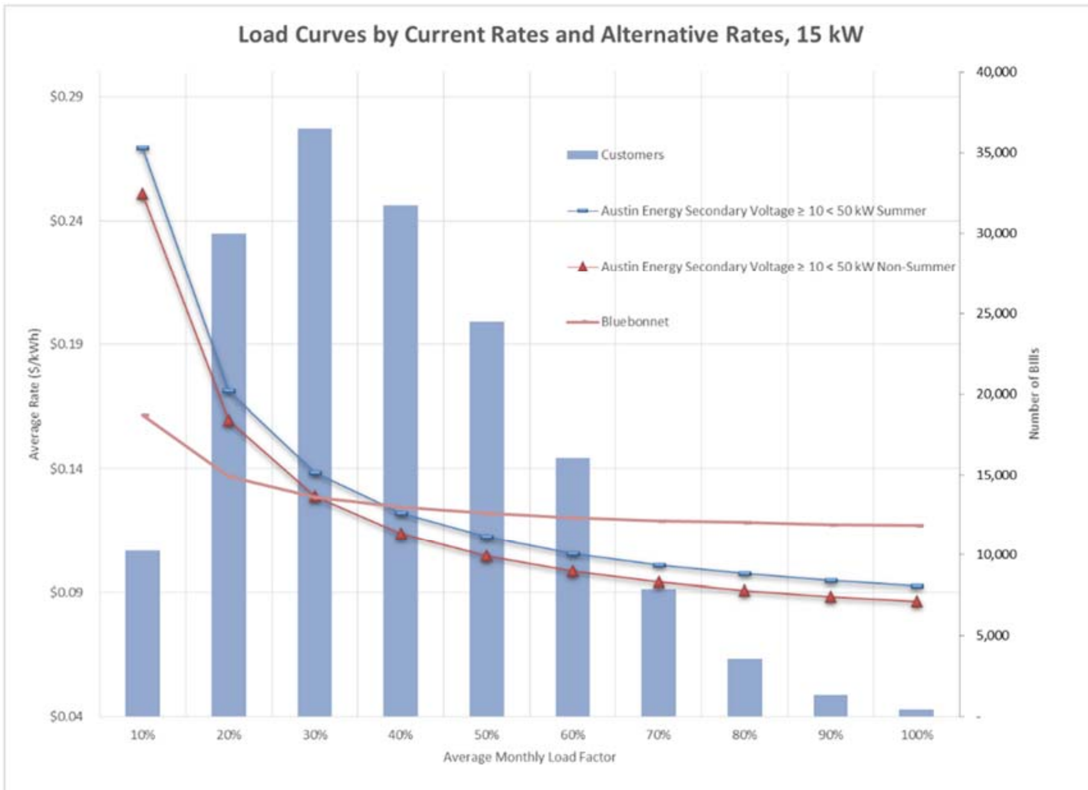


Figure 5-1. BEC Load Curves by Current Rates and Alternative Rates, 15 kW

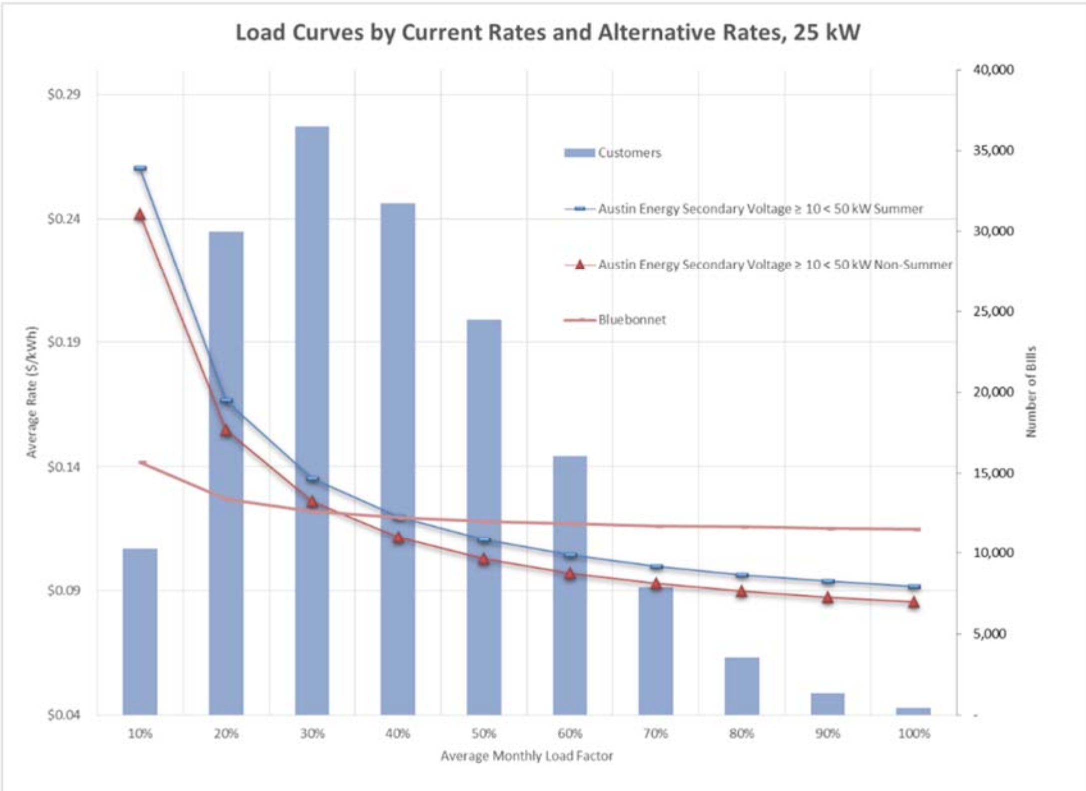


Figure 5-2. BEC Load Curves by Current Rates and Alternate Rates, 25kW

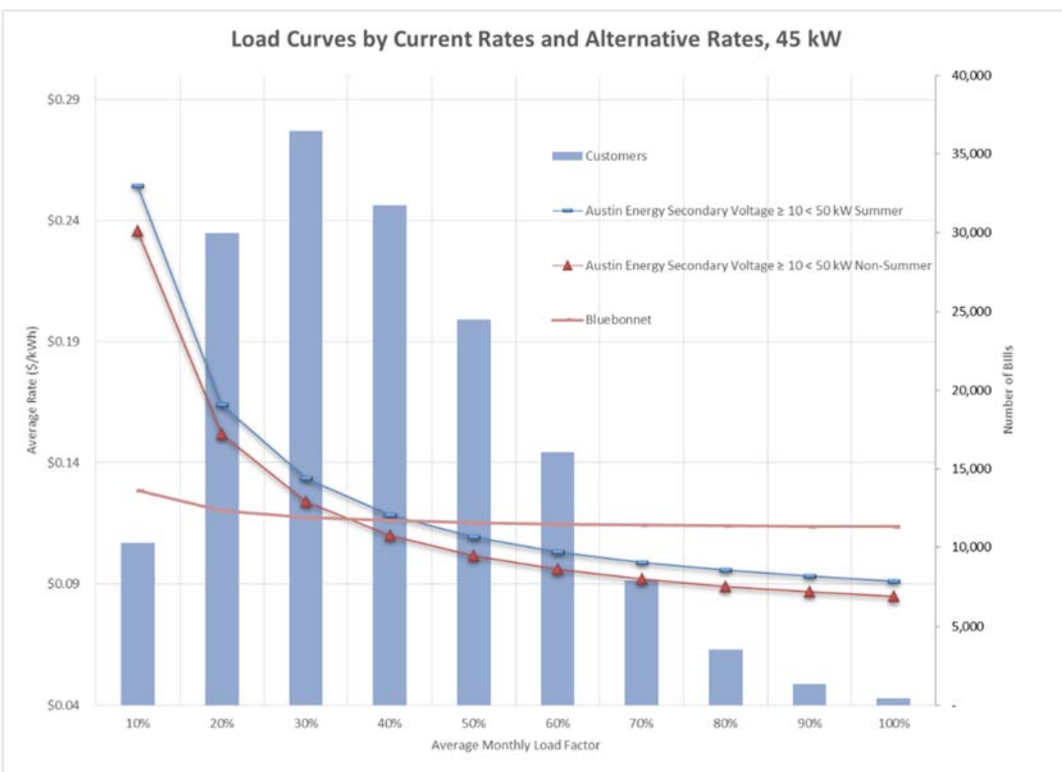


Figure 5-3. BEC Load Curves by Current Rates and Alternative Rates, 45 kW

In all cases, BEC's rate is relatively flat over a range of monthly load factors. Essentially, under the BEC rate structure all customers pay a similar average rate despite large differences in electricity usage and efficiency. As a result, if AE were to adopt the BEC rate structure, high load factor customer monthly bills would increase and low load factor customer bills would decrease. This result is demonstrated in the following table, which shows comparative bills for customers with 15 kW of demand.

Table 5-5
Adjusted BEC Rate Structure Compared to AE's S2 Rate Structure, 15 kW

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	BEC Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
15	10%	1,095	7,523	8.4%	$177.17	$281.78	($104.61)	-37.1%
15	20%	2,190	21,878	33.0%	$299.71	$357.91	($58.21)	-15.5%
15	30%	3,285	22,457	58.2%	$422.24	$434.05	($11.80)	-2.6%
15	40%	4,380	15,811	75.9%	$544.78	$510.18	$34.60	6.5%
15	50%	5,475	10,229	87.4%	$667.31	$586.31	$81.00	13.2%
15	60%	6,570	5,841	94.0%	$789.85	$662.44	$127.41	18.3%
15	70%	7,665	2,622	96.9%	$912.38	$738.57	$173.81	22.5%
15	80%	8,760	1,702	98.8%	$1,034.92	$814.70	$220.22	25.8%
15	90%	9,855	786	99.7%	$1,157.46	$890.84	$266.62	28.6%
15	100%	10,950	283	100.0%	$1,279.99	$966.97	$313.02	30.9%

Approximately 58 percent of S2 customers would experience a rate decrease under the BEC rate structure and 42 percent would experience a rate increase. The BEC rate structure does a poor job of recognizing cost of service results, which indicates that high low factor customers are less expensive to serve than low load factor customers. Therefore, high load factor customers pay too much under this rate structure and subsidize lower load factor customers.

Additionally, with only a customer charge and energy rate, there is no mechanism to measure or enforce power factor, so the cost of poor power factor is distributed among customers in the class.

CPS Energy

Currently, CPS Energy (CPS) is one of the largest public power utilities in the country. CPS Energy owns a diverse generation portfolio comprised of 43 percent natural gas, 28 percent coal, 14 percent nuclear and 14 percent wind. In recent years, CPS has embraced an aggressive strategy surrounding energy efficiency and conservation efforts, expanding renewable energy resources and maintaining a strong commitment to the environment.

The applicable CPS rate for the benchmarking review is the General Service (PL) Rate. The PL Rate has wide applicability to all commercial customers. Although there is no specific maximum demand associated with the PL rate, comparing pricing and rate structures with other alternative applicable CPS rate, Large Lighting and Power Service (LLP), indicates that the

PL rate would be the best choice for most commercial customers with maximum monthly demands of between 10 kW and 50kW.

A summary of the PL rate compared to AE's S2 rate is shown in the following table.

Table 5-6
AE and CPS Rate Comparison

Rate Structure Comparison	AE's Secondary Voltage 10kW to 50kW (S2)	CPS's PL <50kW	CPS's PL <50kW (Adjusted)
Customer Charge ($/month)	25.00	8.75	14.07
Electric Delivery ($/kW billed)	4.00	N/A	N/A
Demand Charge ($/kW billed)			
Summer	6.15	N/A	N/A
Non-Summer	5.15	N/A	N/A
Energy Charge (¢/kWh)			
Summer (kWh > 600) (1)	2.914	1.980	3.183
Non-Summer (kWh > 600) (1)	2.414	1.000	1.607
Hours Use Charge (¢/kWh)			
Tier 1 (2)	N/A	7.190	11.558
Tier 2 (2)	N/A	3.320	5.337
Pass-Throughs (¢/kWh)			
Power Supply Adjustment	3.709	N/A	N/A
Customer Assistance Program	0.065	N/A	N/A
Service Area Street Lighting	0.076	N/A	N/A
Energy Efficiency Services	0.522	N/A	N/A
Delivery Charge	N/A	N/A	N/A
Regulatory Charge			
(¢/kWh)	N/A	N/A	N/A
($/kW billed)	2.56	N/A	N/A

Notes:
(1) CPS Summer season is defined as June – September. The seasonal Energy Charge applied by CPS is the Peak Capacity Charge, and is applied to all monthly energy greater than 600 kWh.
(2) Tier 1 includes the first 1,600 kWh, plus 200 kWh for each 1 kW of demand greater than 5 kW. Tier 2 includes all additional energy over 1,600 kW.

The PL rate structure is an "Hours-Use" Rate Structure, which is a structure that recovers cost in alignment with customer load factor. As noted in the footnote on the above table, the size of the first block of a two-tier energy rate is based on a customer's maximum demand. For metered demand above 5 kW, the block grows at 200 kWh per kW. For example, the first block of a 10 kW customer would be 2,600 kWh (1,600 kWh + (10-5)*200 kWh), the first block of a 20 kW customer would be 4,600 kWh (1,600 kWh+ (20-5)*200 kWh), etc. For an individual customer, the amount of energy billed under the Tier 1 versus Tier 2 rate is dependent on the customer's monthly load factor. The load factor threshold is about 27 percent (200hrs/730hrs). Therefore, customers with load factors less than 27 percent have all of their energy billed at the Tier 1 rate. Customers with load factors greater than 27 percent benefit from lower cost energy in Tier 2. Although the rate looks like an energy only rate, the structure of the rate behaves like a demand and energy rate.

The adjusted CPS rate as shown in the above table reflects a prorata adjustment of the rate so that the CPS rate applied to AE customers served under the S2 would generate an equal amount of revenue. In other words, AE would be indifferent to either rate as both rates generated the same amount of revenue. The analysis supporting this revenue neutral calculation is shown in Exhibit 2 - CPS Energy Adjusted and Compared to AE's Secondary Service 10 kW But Less Than 50 kW Rate, attached at the end of this Report.

Graphical comparisons of CPS's PL rate compared to AE's S2 rate for customers with monthly maximum demands of 15 kW, 25 kW, and 45 kW are shown in the following graphs.

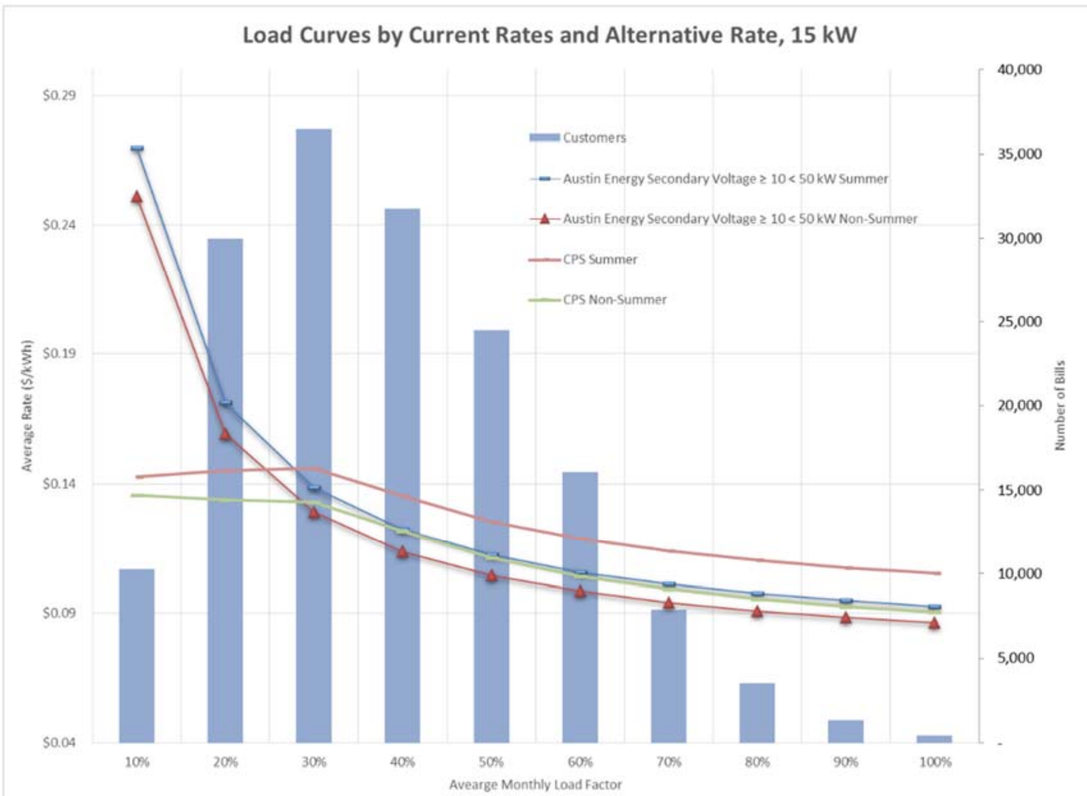


Figure 5-4. CPS Load Curves by Current Rates and Alternative Rate, 15 kW

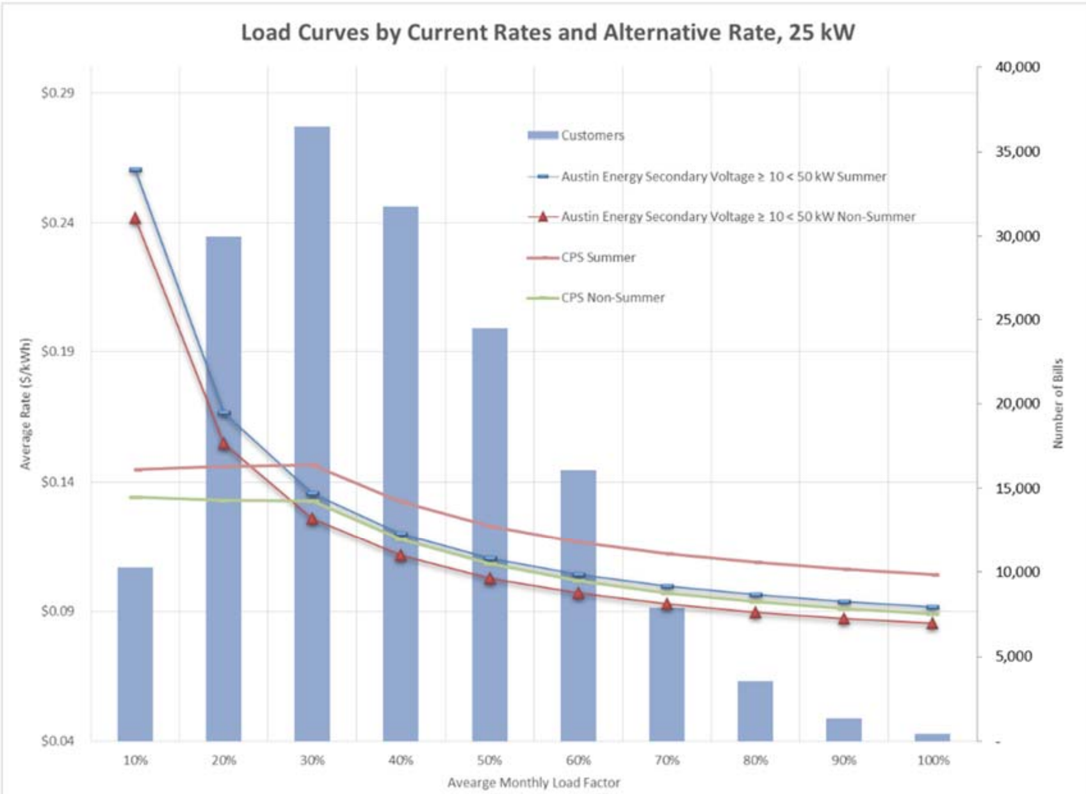


Figure 5-5. CPS Load Curves by Current Rates and Alternative Rate, 25 kW

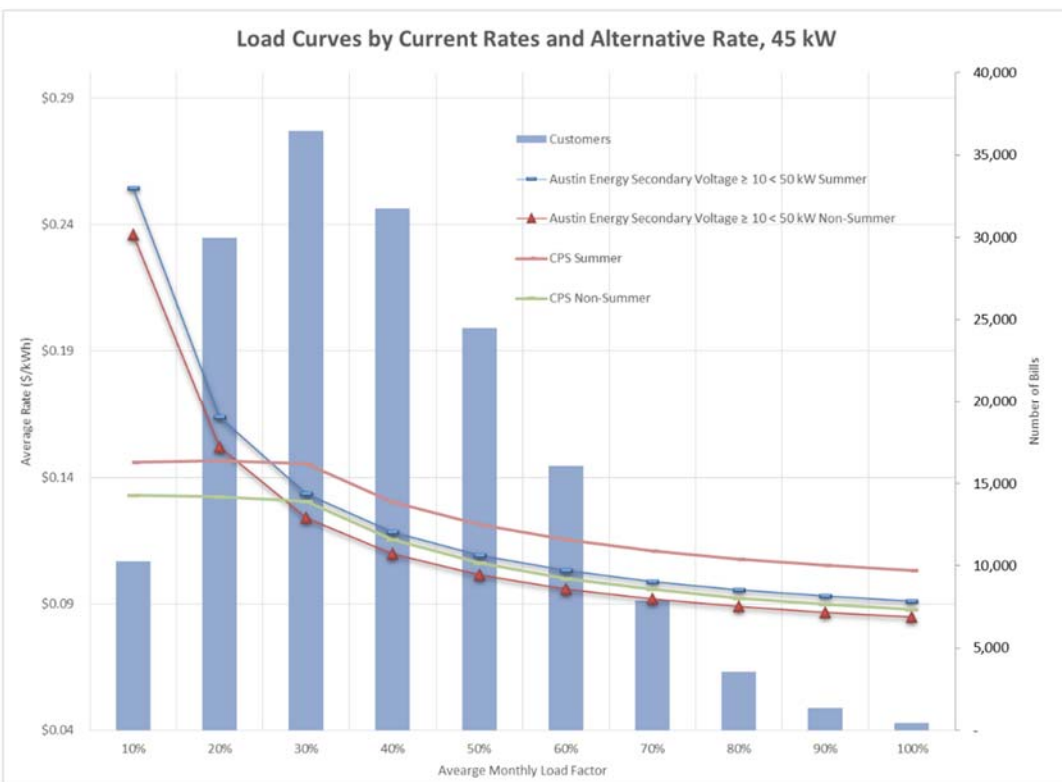


Figure 5-6. CPS Load Curves by Current Rates and Alternative Rate, 45 kW

As indicated in the above graphs, the “Hours-Use” rate structure behaves in a similar manner as a rate structure with a demand and energy charge except that an “Hours-Use” rate structure caps the amount a low load factor customer pays on a $/kWh basis. In this case, the CPS structure caps the effective rate at about $0.14 per kWh for customers with load factors less than 30 percent.

Because demand is a key component of the “Hours-Use” calculation, power factor penalty charges apply in a similar manner as that of a demand and energy rate.

If AE were to adopt the CPS rate structure, low load factor customer monthly bills would decrease and high load factor customer bills would experience a slight increase, to provide this rate protection to low load factor customers. This result is demonstrated in the following table, which shows comparative bills for customers with 15 kW of demand.

Table 5-7
Adjusted CPS Rate Structure Compared to AE’s S2 Rate Structure

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	CPS Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
15	10%	1,095	7,523	8.4%	$151.18	$281.78	($130.60)	-46.3%
15	20%	2,190	21,878	33.0%	$301.08	$357.91	($56.83)	-15.9%
15	30%	3,285	22,457	58.2%	$450.99	$434.05	$16.95	3.9%
15	40%	4,380	15,811	75.9%	$552.38	$510.18	$42.20	8.3%
15	50%	5,475	10,229	87.4%	$634.17	$586.31	$47.86	8.2%
15	60%	6,570	5,841	94.0%	$715.95	$662.44	$53.51	8.1%
15	70%	7,665	2,622	96.9%	$797.74	$738.57	$59.17	8.0%
15	80%	8,760	1,702	98.8%	$879.53	$814.70	$64.83	8.0%
15	90%	9,855	786	99.7%	$961.32	$890.84	$70.49	7.9%
15	100%	10,950	283	100.0%	$1,043.11	$966.97	$76.14	7.9%

Approximately 33 percent of S2 customers would experience a rate decrease under the CPS rate structure and 66 percent would experience a rate increase. For customers with monthly load factors of 30 percent or greater, the rate structure follows cost of service principles. Low load factor customers are subsidized but the degree of subsidy is less than those observed under a customer and energy-only rate structure.

Fort Collins Utilities

Fort Collins Utilities (FCU) serves approximately 68,000 customers in Fort Collins, Colorado. FCU is an all requirements wholesale customer of Platte River Power Authority (PRPA). PRPA resource mix predominantly includes 75.4 percent of coal, 18.9 percent of hydropower, 3.6 percent of renewables and other miscellaneous sources. In an effort to minimize its carbon footprint, given that its power supplier has a significant amount of coal resource, FCU has aggressively pursued energy conservation, efficiency, renewable energy, and sustainability programs for many years. FCU energy policy goals include high reliability, low rates, and minimizing environmental impacts.

The applicable FCU rate structures for the rate structure review are the General Service <25 kW and the General Service 25-750 kW rates. The General Service <25 kW is available to all commercial customers with maximum demands less than 25 kW per billing cycle. The General Service 25-750 kW is available to all commercial customers with maximum demand greater than 25 kW but less than 750 kW per billing cycle. A summary of each these rates is shown in the following table.

Table 5-8
AE and FCU Rate Comparison

Rate Structure Comparison	AE's Secondary Voltage 10kW to 50kW	FCU General Service <25kW	FCU General Service 25kW to 50kW	FCU General Service <25kW (Adjusted)	FCU General Service 25kW to 50kW (Adjusted)
Customer Charge ($/month)	25.00	11.74	11.74	16.63	16.63
Electric Delivery ($/kW billed)	4.00	N/A	N/A	N/A	N/A
Demand Charge ($/kW billed)					
Summer	6.15	N/A	7.52	N/A	10.65
Non-Summer	5.15	N/A	4.37	N/A	6.19
Demand Charge (¢/kWh billed)					
Summer (1)	N/A	2.77	N/A	3.92	N/A
Non-Summer	N/A	1.49	N/A	2.11	N/A
Energy Charge (¢/kWh)					
Summer (1)	2.914	4.16	4.16	5.89	5.89
Non-Summer	2.414	4.00	4.00	5.66	5.67
Distribution Charge (¢/kWh)	N/A	2.27	1.76	3.22	2.49
Pass-Throughs (¢/kWh)					
Power Supply Adjustment	3.709	N/A	N/A	N/A	N/A
Customer Assistance Program	0.065	N/A	N/A	N/A	N/A
Service Area Street Lighting	0.076	N/A	N/A	N/A	N/A
Energy Efficiency Services	0.522	N/A	N/A	N/A	N/A
Regulatory Charge					
(¢/kWh)	N/A	N/A	N/A	N/A	N/A
($/kW billed)	2.56	N/A	N/A	N/A	N/A
Taxes and Franchise Fee	N/A	6.0%	6.0%	6.0%	6.0%

Notes:
(1) FCU Summer season is defined as June – August.

FCU provides service to commercial customers between 10 kW and 50 kW of monthly demand under two different rate structures. FCU creates a boundary between customers at less than

25 kW of demand (General Service <25 kW), and customers with 25 kW to 750 kW of monthly demand (General Service 25 kW - 750 kW). Both General Service rates identify a demand charge; however, the distinction between the two demand charges is that customers with less than 25 kW of demand have a demand charge based on kWh, where customers with monthly demand between 25 kW and 50 kW have a demand charge based on kW.

The adjusted FCU rate as shown in the above table reflects a prorata adjustment of the rate so that the FCU rates in total applied to AE customers served under the AE S2 rate would generate an equal amount of revenue. In other words, AE would be financially indifferent to either rate as both rates generated the same amount of revenue (although the FCU rate would not necessarily support the City of Austin's goals and objectives). The analysis supporting this revenue neutral calculation is shown in Exhibit 3 of this Report.

Graphical comparisons of FCU General Service <25 kW and General Service 25-750 kW rates compared to AE's S2 rate for customers with monthly maximum demands of 15 kW, 25 kW, and 45 kW are shown in the following graphs.

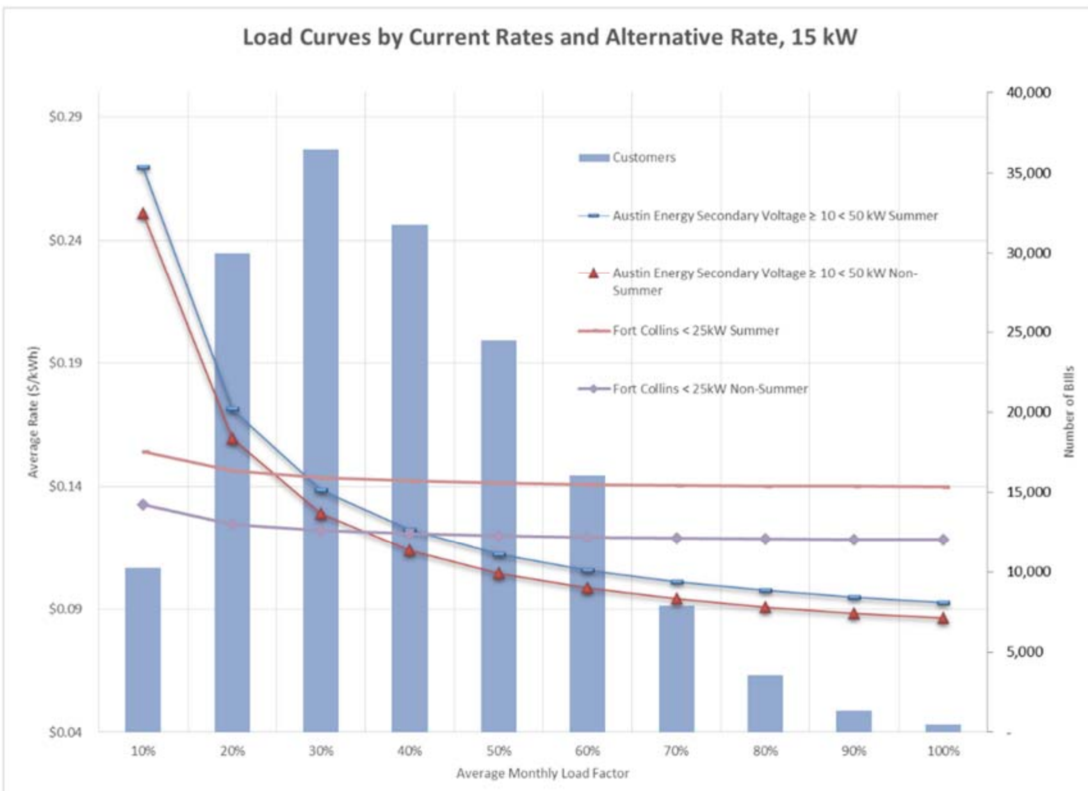


Figure 5-7. FCU Load Curves by Current Rates and Alternate Rate, 15 kW

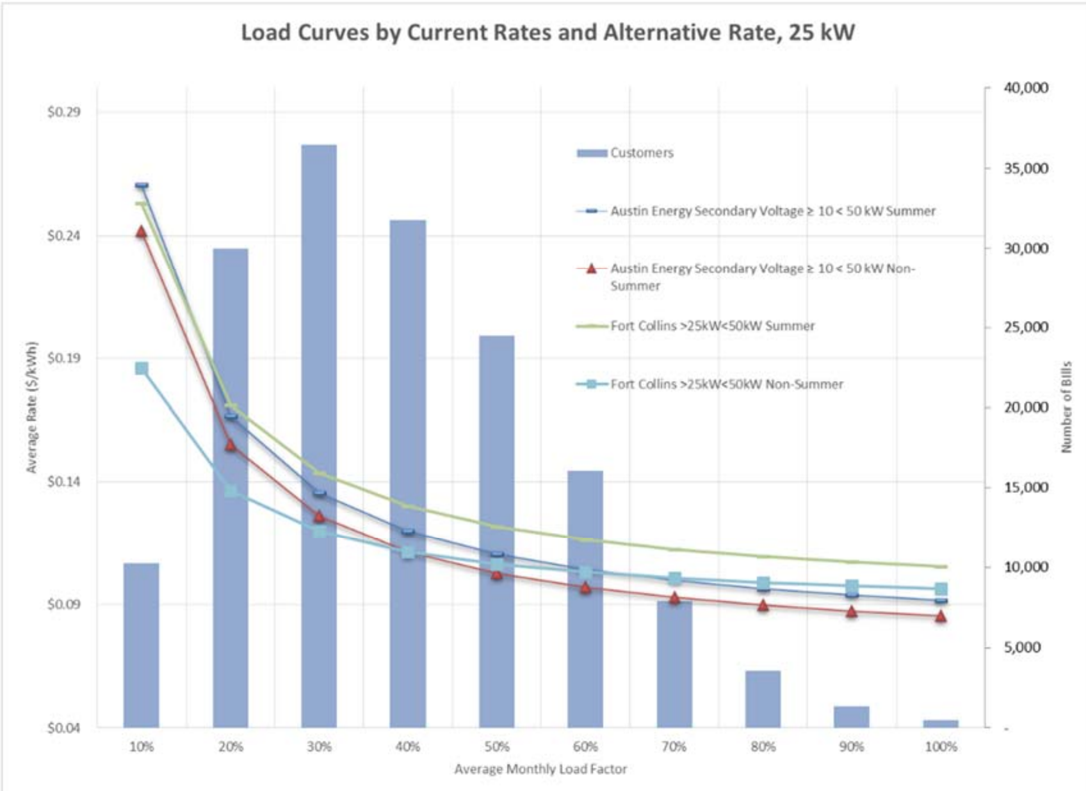


Figure 5-8. FCU Load Curves by Current Rates and Alternate Rate, 25 kW

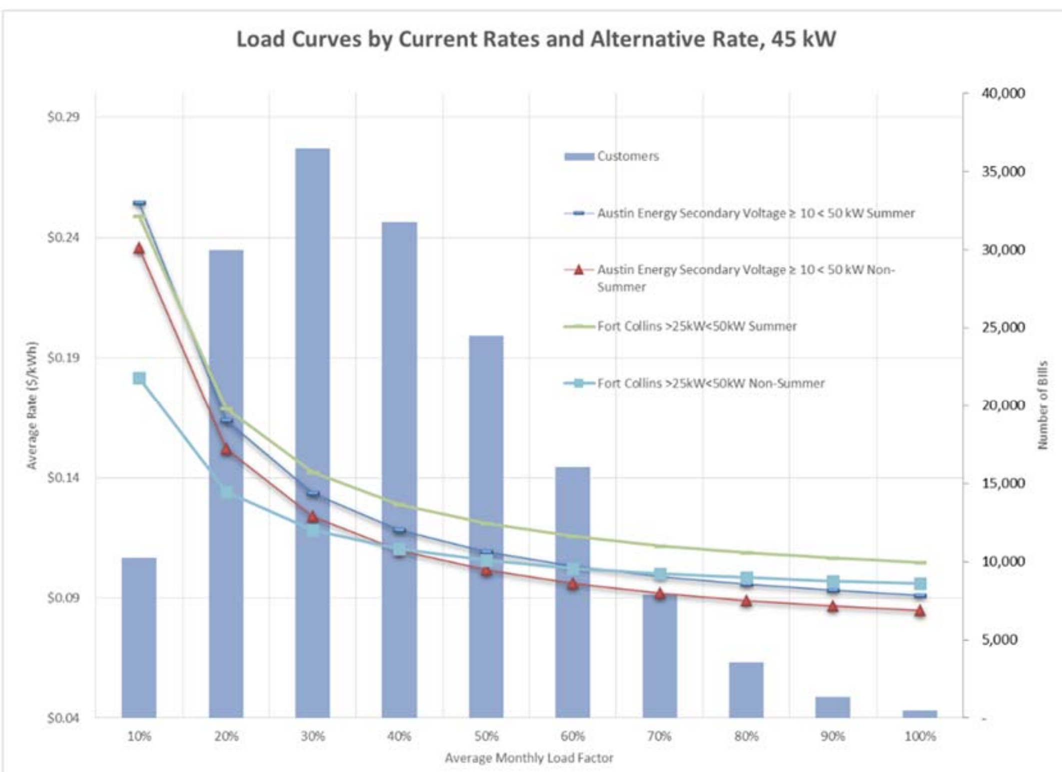


Figure 5-9. FCU Load Curves by Current Rates and Alternate Rate, 45 kW

For customers with demand less than 25 kW, the FCU General Service <25 kW rate is applied. This rate is relatively flat over the range of monthly load factors. Under this rate structure, all customers pay a similar average rate despite potentially large differences in electricity usage and efficiency.

For the two scenarios presented for 25 kW and 45 kW, the FCU General Service 25-750 kW is applied. As shown above, for customers between 25 kW and 50 kW, the rate structure is similar to AE's current rate. The shape of the FCU rate curve is similar to the AE S2 rate curve during the summer season and slightly flatter during the non-summer season. The difference between the season can be attributed to a lower demand charge during the non-summer season. The summer/ non-summer pricing differentials are greater under the FCU rate structure than AE's S2 rate.

If AE were to adopt the FCU's rate structure, the impact on customers would vary depending upon customer size. For customers with demand less than 25 kW, the FCU rate structure is fairly flat and does not vary by monthly load factor. Although most customers in this class would experience an increase in monthly bills under the FCU rate structure, high load factor customers would experience the largest increase. This result is demonstrated in the following table.

Table 5-9
Adjusted FCU Rate Structure Compared to AE's S2 Rate Structure, 15 kW

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	Fort Collins Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
15	10%	1,095	7,523	8.4%	$255.42	$281.78	($26.36)	-9.4%
15	20%	2,190	21,878	33.0%	$366.21	$357.91	$8.30	2.3%
15	30%	3,285	22,457	58.2%	$477.01	$434.05	$42.96	9.9%
15	40%	4,380	15,811	75.9%	$587.80	$510.18	$77.63	15.2%
15	50%	5,475	10,229	87.4%	$698.60	$586.31	$112.29	19.2%
15	60%	6,570	5,841	94.0%	$809.39	$662.44	$146.95	22.2%
15	70%	7,665	2,622	96.9%	$920.18	$738.57	$181.61	24.6%
15	80%	8,760	1,702	98.8%	$1,030.98	$814.70	$216.27	26.5%
15	90%	9,855	786	99.7%	$1,141.77	$890.84	$250.94	28.2%
15	100%	10,950	283	100.0%	$1,252.57	$966.97	$285.60	29.5%

Approximately 8 percent of S2 customers with demand of less than 25 kW would experience a rate decrease under the FCU rate structure and 92 percent would experience a rate increase. The rate structure does a poor job of recognizing cost of service principles; therefore, high load factor customers pay too much under this rate structure and subsidize lower load factor customers.

Additionally, with only a customer charge and energy rate, there is no mechanism to measure or enforce power factor, so the cost of poor power factor is distributed among customers in the class operating with greater efficiency.

FCU's rate structure for customers with a demand of 25 kW or greater includes a demand charge and recognizes the cost differentiation between low and high load factor customers. As a result, when comparing FCU bills with AE's S2 rate, bill differentials are generally smaller than for customers with demand less than 25 kW. This result is demonstrated in the following table.

Table 5-10
Adjusted FCU Rate Structure Compared to AE's S2 Rate Structure, 25 kW

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	Fort Collins Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
25	10%	1,825	2,424	3.3%	$312.14	$452.97	($140.83)	-31.1%
25	20%	3,650	8,100	14.5%	$483.64	$579.86	($96.21)	-16.6%
25	30%	5,475	14,013	33.7%	$655.15	$706.74	($51.59)	-7.3%
25	40%	7,300	15,937	55.6%	$826.65	$833.63	($6.97)	-0.8%
25	50%	9,125	14,284	75.2%	$998.16	$960.51	$37.65	3.9%
25	60%	10,950	10,219	89.2%	$1,169.67	$1,087.40	$82.26	7.6%
25	70%	12,775	5,262	96.5%	$1,341.17	$1,214.29	$126.88	10.4%
25	80%	14,600	1,843	99.0%	$1,512.68	$1,341.17	$171.50	12.8%
25	90%	16,425	550	99.8%	$1,684.18	$1,468.06	$216.12	14.7%
25	100%	18,250	178	100.0%	$1,855.69	$1,594.95	$260.74	16.3%

For customers with a monthly demand of 25 kW or greater, approximately 56 percent of S2 customers would experience a rate decrease under the Fort Collins rate structure and 44 percent would experience a rate increase. The rate structure is similar to AE's current rate; however, the FCU rate places a larger percentage of cost recovery in energy charges resulting in a flatter rate curve. This flatter curve, while following FCU costs, aids low load factor customers. Additionally, the Fort Collins rate structure creates a greater differential between the summer and non-summer demand charges, resulting in a meaningfully higher summer seasons costs compared to the S2 rate.

Los Angeles Department of Water and Power

The Los Angeles Department of Water and Power (LADWP) serves 1.4 million residential and business customers in the City of Los Angeles. LADWP is the largest public power utility in the country. LADWP's resource mix includes 42 percent coal, 23 percent renewables, 17 percent natural gas, 10 percent nuclear, 4 percent hydroelectric, and 4 percent from miscellaneous other sources. LADWP business objectives include the aggressive pursuit of energy efficiency, carbon emission reductions, and achievement of California renewable energy portfolio standards.

The applicable LADWP rate structures for the rate structure review are the Small Commercial <30 kW and the Primary Service 30 kW and Greater rates. The Small Commercial <30 kW rate is available to all commercial customers with maximum demands less than 30 kW per billing cycle. The Primary Service 30 kW and Greater rate is available to all commercial customers with maximum demand greater than 30 kW per billing cycle. LADWP does not have a Secondary Service >30 kW and Greater rate class. Secondary service customers with demands greater than 30 kW are referred to the Primary Service 30 kW and Greater rate per Small Commercial <30 kW tariff language.

A summary of each these rates is shown in the following table.

Table 5-11
AE and LADWP Rate Comparison

Rate Structure Comparison	AE's Secondary Service 10kW to 50kW	LADWP's Small General Service <30kW	LADWP's Primary Service ≥30kW	LADWP's Small General Service <30kW (Adjusted)	LADWP's Primary Service ≥30kW (Adjusted)
Customer Charge ($/month)	25.00	6.50	6.50	5.91	5.91
Electric Delivery ($/kW billed)	4.00	5.00	5.00	4.55	4.55
Demand Charge ($/kW billed)					
Summer	6.15	N/A	9.00	N/A	8.19
Non-Summer	5.15	N/A	5.50	N/A	5.00
Energy Charge (¢/kWh)					
Summer (1)	2.914	6.558	3.645	5.966	3.316
Non-Summer	2.414	4.268	2.995	3.883	2.725
Pass-Throughs (¢/kWh)					
Power Supply Adjustment	3.709	5.690	5.690	5.176	5.176
Customer Assistance Program	0.065	N/A	N/A	N/A	N/A
Service Area Street Lighting	0.076	N/A	N/A	N/A	N/A
Energy Efficiency Services	0.522	N/A	N/A	N/A	N/A
Pass-Throughs ($/kW)					
Electric Subsidy Adjustment	N/A	0.46	0.46	0.42	0.42
Reliability Cost Adjustment	N/A	0.96	0.96	0.87	0.87
Regulatory Charge					
(¢/kWh)	N/A	N/A	N/A	N/A	N/A
($/kW billed)	2.56	N/A	N/A	N/A	N/A

Notes:
(1) LADWP Summer season is defined as June – September.

LADWP's provides service to commercial customers between 10 kW and 50 kW of monthly demand under two different rate structures. LADWP creates a boundary between customers with less than 30 kW of monthly demand (Small Commercial <30 kW), and customers with

30 kW or greater (Primary Service >30 kW). The Small Commercial <30 kW rate structure does include a demand charge which recovers the costs of the electric delivery charge and several pass-through charges.

The Primary Service > 30kW rate structure includes demand charges for generation, electric delivery and several pass-through charges. The adjusted LADWP rate as shown in the table above reflects a prorata adjustment of the rate so that the LADWP rate applied to AE customers served under the S2 rate would generate an equal amount of revenue. In other words, AE would be financially indifferent to either rate as both rates generated the same amount of revenue (although the LADWP rate would not necessarily support the City of Austin's goals and objectives). The analysis supporting this revenue neutral calculation is shown in Exhibit 4 of this report.

Graphical comparisons of LADWP's Small Commercial <30 kW and Primary Service 30 kW and Greater rate compared to AE's S2 rate for customers with monthly maximum demands of 15kW, 25kW and 45kW are shown in the following graphs.

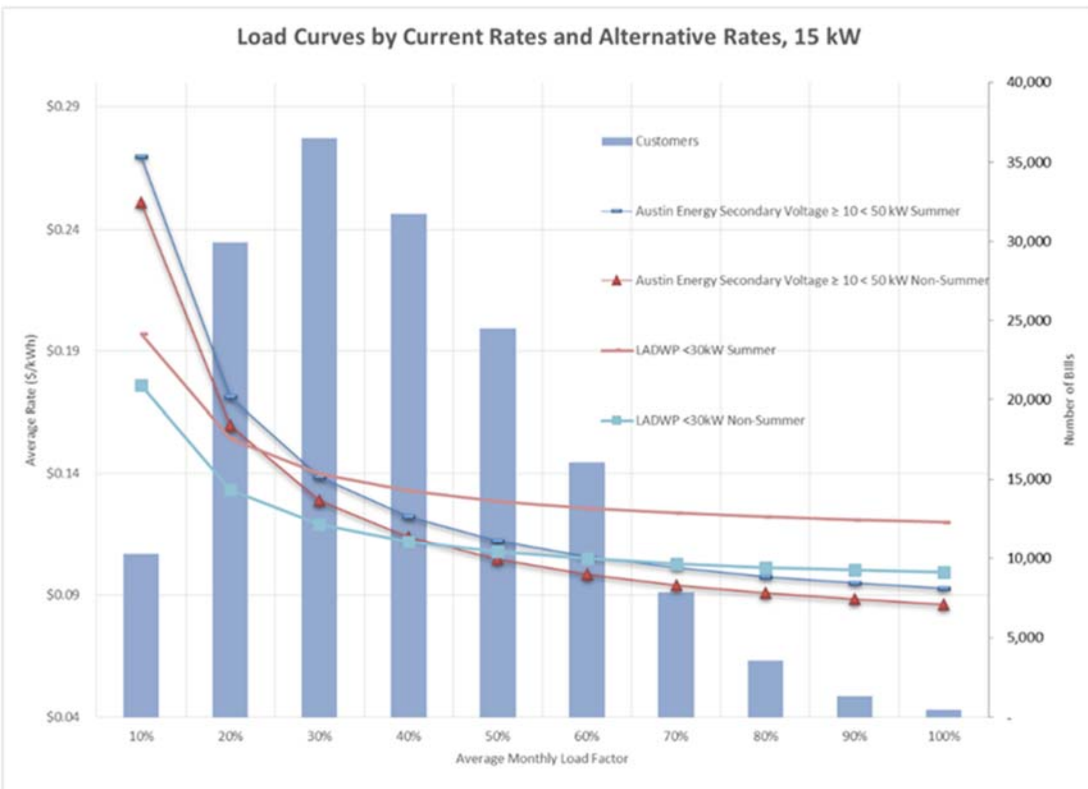


Figure 5-10. LADWP Load Curves by Current Rates and Alternative Rates, 15 kW

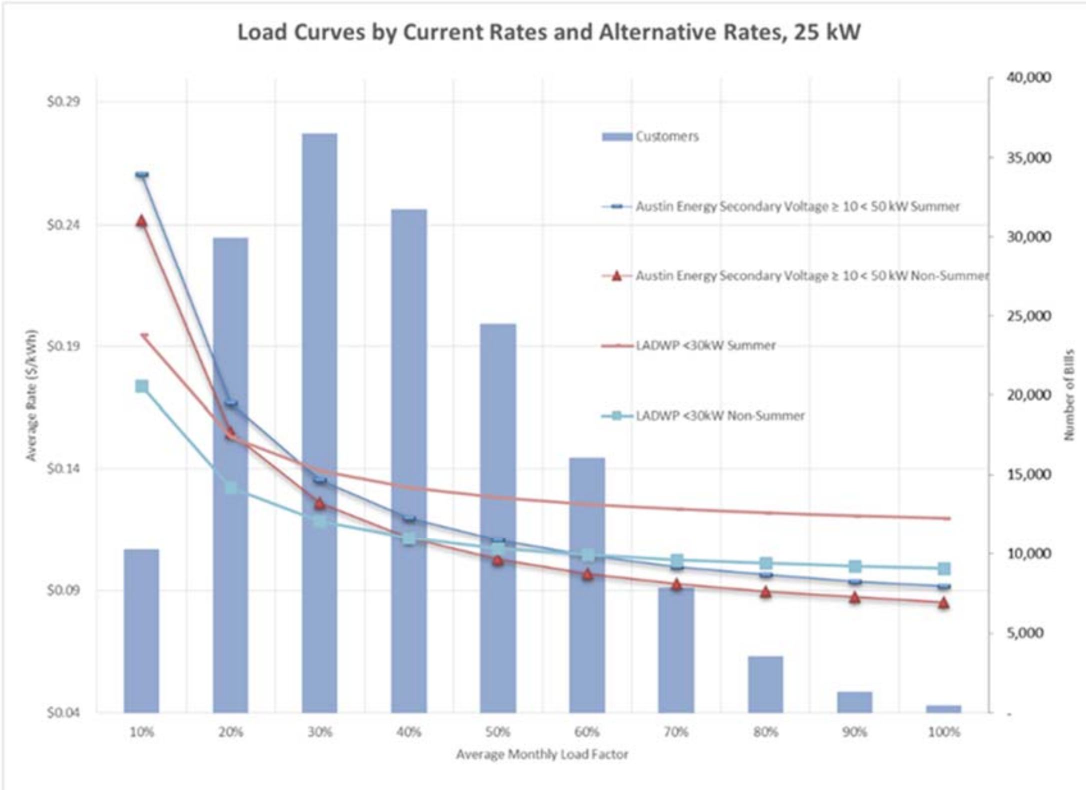


Figure 5-11. LADWP Load Curves by Current Rates and Alternative Rates, 25 kW

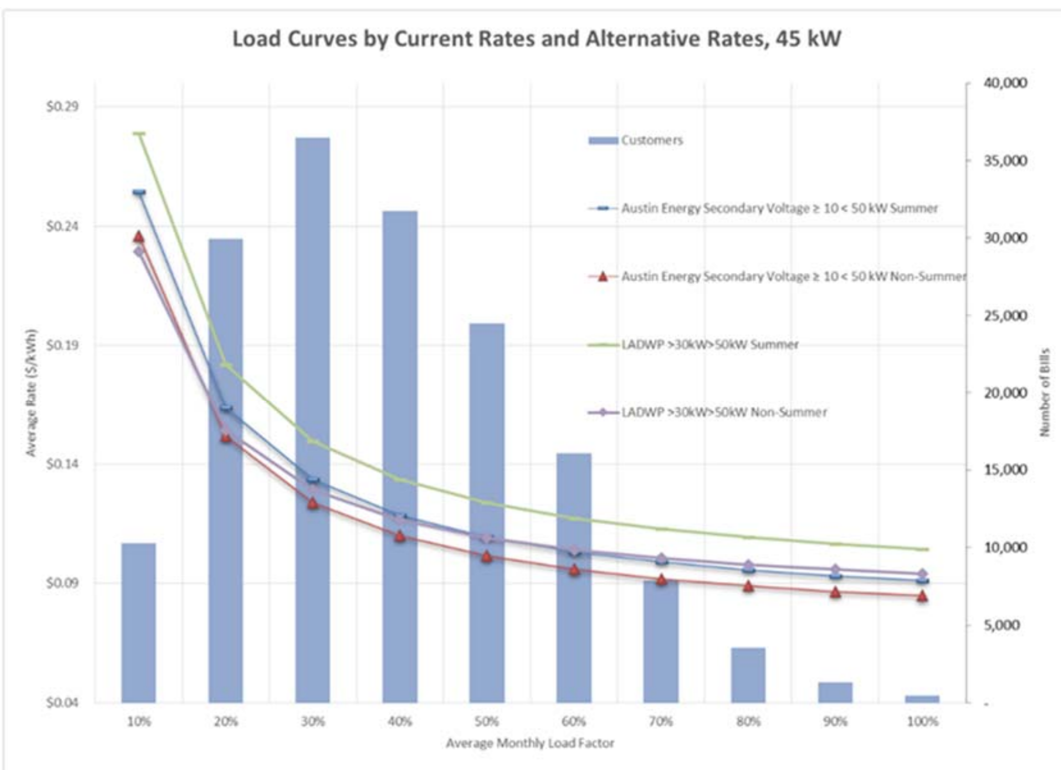


Figure 5-12. LADWP Load Curves by Current Rates and Alternative Rates, 45 kW

In the 15 kW and 25 kW scenarios shown above, LADWP's Small Commercial rate does recognize cost of service differences associated with load factor and the shape of the curve is similar but flatter than the AE S2 rate. This differential can be directly attributed to a lower demand charge compared to the AE S2 rate. As previously mentioned, the AE rate structure only includes a demand component associated primarily with the distribution delivery charge.

In the 45 kW scenario, the Primary Service rate structure is applied under the LADWP's rate tariff. As shown above, for customers between 30 kW and 50 kW, the Primary Service rate structure is similar to AE's current S2 rate structure.

If AE were to adopt the LADWP's rate structure, customers with a monthly demand of less than 30 kW would experience a cost shift due to the flatter shape of the curve. Customers with load factors less than 30 percent would experience a lower overall average rate compared to AE's S2 rate. This result is demonstrated in the following table.

Table 5-12
Adjusted LADWP Rate Structure Compared to AE's S2 Rate Structure, 15 kW

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	LADWP Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
15	10%	1,095	7,523	8.4%	$200.33	$281.78	($81.46)	-28.9%
15	20%	2,190	21,878	33.0%	$307.13	$357.91	($50.78)	-14.2%
15	30%	3,285	22,457	58.2%	$413.93	$434.05	($20.11)	-4.6%
15	40%	4,380	15,811	75.9%	$520.74	$510.18	$10.56	2.1%
15	50%	5,475	10,229	87.4%	$627.54	$586.31	$41.23	7.0%
15	60%	6,570	5,841	94.0%	$734.34	$662.44	$71.90	10.9%
15	70%	7,665	2,622	96.9%	$841.15	$738.57	$102.57	13.9%
15	80%	8,760	1,702	98.8%	$947.95	$814.70	$133.25	16.4%
15	90%	9,855	786	99.7%	$1,054.75	$890.84	$163.92	18.4%
15	100%	10,950	283	100.0%	$1,161.56	$966.97	$194.59	20.1%

Approximately 58 percent of S2 customers with demand of less than 30 kW would experience a rate decrease under the LADWP rate structure and 42 percent would experience a rate increase. A lower demand charge in the rate structure shifts costs from low load factor customers to high load factor customers. The rate design partially follows cost of service principles as fixed cost associated with the distribution system are appropriately distributed between customers in the class. However, fixed costs associated with production costs are averaged over all customers in the class without consideration of load factor differentials.

LADWP's rate structure for customers with a monthly demand of greater than 30 kW includes a demand charge associated with the production and distribution functions. As a result, when comparing LADWP's bills with AE's S2 rate, bill differentials are generally relatively small. This result is demonstrated in the following table.

Table 5-13
Adjusted LADWP Rate Structure Compared to AE's S2 Rate Structure, 45 kW

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	LADWP Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
45	10%	3,285	2,424	3.3%	$807.69	$795.35	$12.35	1.6%
45	20%	6,570	8,100	14.5%	$1,073.72	$1,023.74	$49.98	4.9%
45	30%	9,855	14,013	33.7%	$1,339.75	$1,252.14	$87.62	7.0%
45	40%	13,140	15,937	55.6%	$1,605.78	$1,480.53	$125.25	8.5%
45	50%	16,425	14,284	75.2%	$1,871.81	$1,708.93	$162.89	9.5%
45	60%	19,710	10,219	89.2%	$2,137.84	$1,937.32	$200.52	10.4%
45	70%	22,995	5,262	96.5%	$2,403.87	$2,165.72	$238.15	11.0%
45	80%	26,280	1,843	99.0%	$2,669.90	$2,394.11	$275.79	11.5%
45	90%	29,565	550	99.8%	$2,935.93	$2,622.51	$313.42	12.0%
45	100%	32,850	178	100.0%	$3,201.96	$2,850.90	$351.05	12.3%

For customers with a monthly demand of 30 kW or greater, all S2 customers would experience a rate increase under the LADWP rate structure. This is related to the manner in which the Small General Services and Primary Service rates are structured to recover the $104,949,630 revenue generated by the AE S2 class. The LADWP's Primary Service rate structure for customers with a demand greater than 30 kW is very similar to AE's current S2 rate, so the magnitude of the changes would be relatively small.

Pedernales Electric Cooperative

Pedernales Electric Cooperative (PEC) is a consumer owned distribution cooperative serving customers bordering AE's service territory. PEC is a wholesale customer of the LCRA. The LCRA's wholesale power costs are billed to PEC on an energy only basis; therefore, the majority of PEC fixed costs are related to its distribution system.

The applicable PEC rate for the rate structure review is the Small Power <50 kW rate. The Small Power <50 kW rate is available to all commercial and industrial customers and other consumers whose peak demand is consistently less than 50 kW per billing cycle. A summary of the Small Power <50 kW rate compared to AE's S2 rate is shown in the following table.

Table 5-14
AE and PEC Rate Comparison

Rate Structure Comparison	AE's Secondary Voltage 10kW to 50kW (S2)	PEC's Small Power <50kW	PEC's Small Power <50kW (Adjusted)
Customer Charge ($/month)	25.00	37.50	45.30
Electric Delivery ($/kW billed)	4.00	N/A	N/A
Demand Charge ($/kW billed)			
Summer	6.15	N/A	N/A
Non-Summer	5.15	N/A	N/A
Energy Charge (¢/kWh)			
Summer	2.914	7.208	8.708
Non-Summer	2.414	7.208	8.708
Pass-Throughs (¢/kWh)			
Power Supply Adjustment	3.709	0.100	0.100
Customer Assistance Program	0.065	N/A	N/A
Service Area Street Lighting	0.076	N/A	N/A
Energy Efficiency Services	0.522	N/A	N/A
Delivery Charge	N/A	2.101	2.538
Regulatory Charge			
(¢/kWh)	N/A	N/A	N/A
($/kW billed)	2.56	N/A	N/A

PEC's Small Power <50 kW rate does not include a demand charge.

The adjusted PEC rate as shown in the table above reflects a prorata adjustment of the rate so that the PEC rate applied to AE customers served under the S2 rate would generate an equal amount of revenue. In other words, AE would be financially indifferent to either rate as both rates generated the same amount of revenue (although the PEC rate would not necessarily support the City of Austin's goals and objectives). The analysis supporting this revenue neutral calculation is shown in Exhibit 5 of this report.

Graphical comparisons of PEC's Small Power Rate <50 kW compared to AE's S2 rate for customers with monthly maximum demands of 15 kW, 25 kW, and 45 kW are shown in the following graphs.

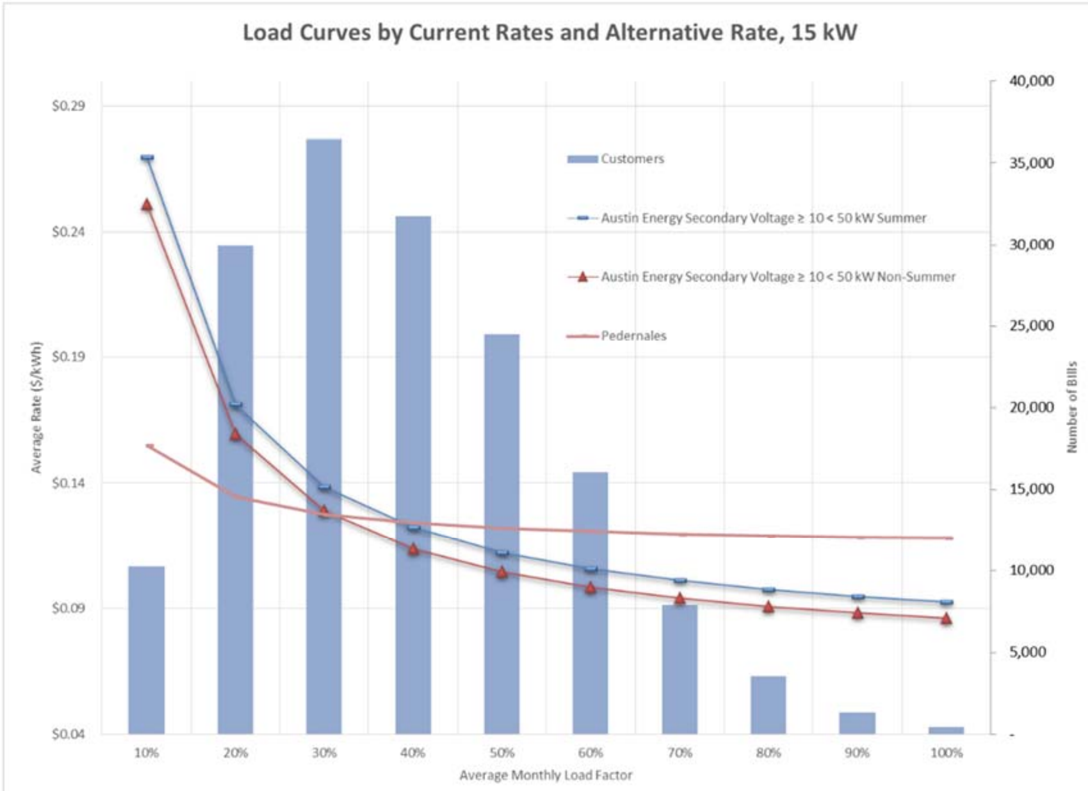


Figure 5-13. PEC Load Curves by Current Rates and Alternative Rate, 15 kW

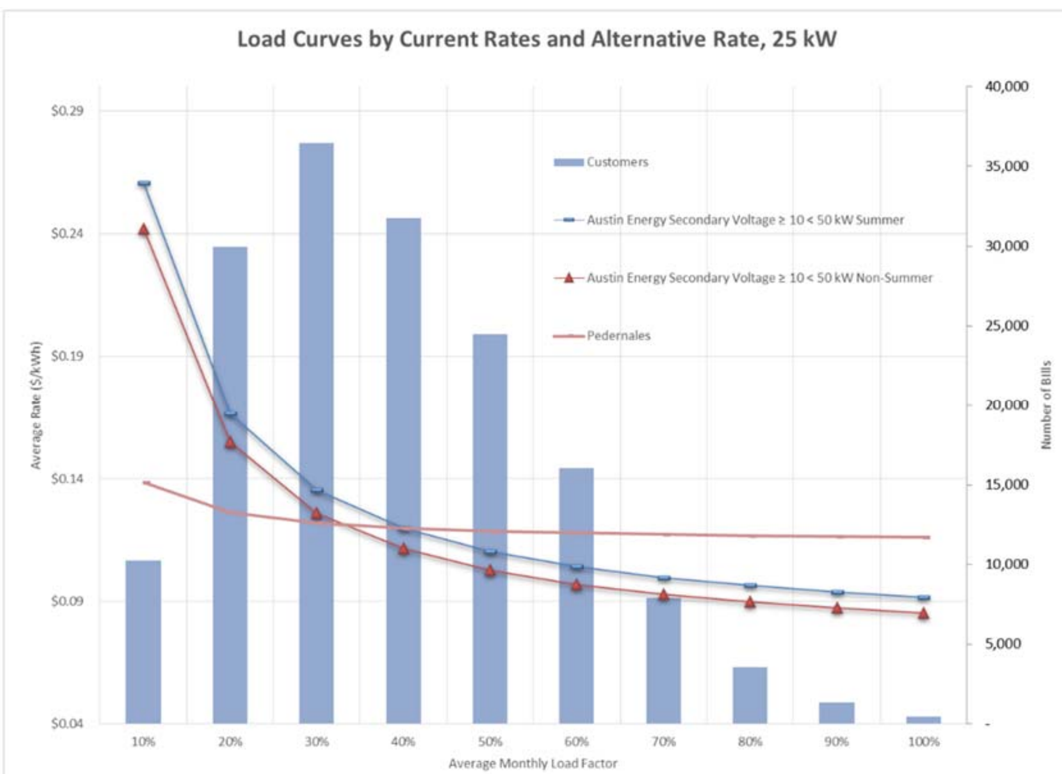


Figure 5-14. PEC Load Curves by Current Rates and Alternative Rate, 25 kW

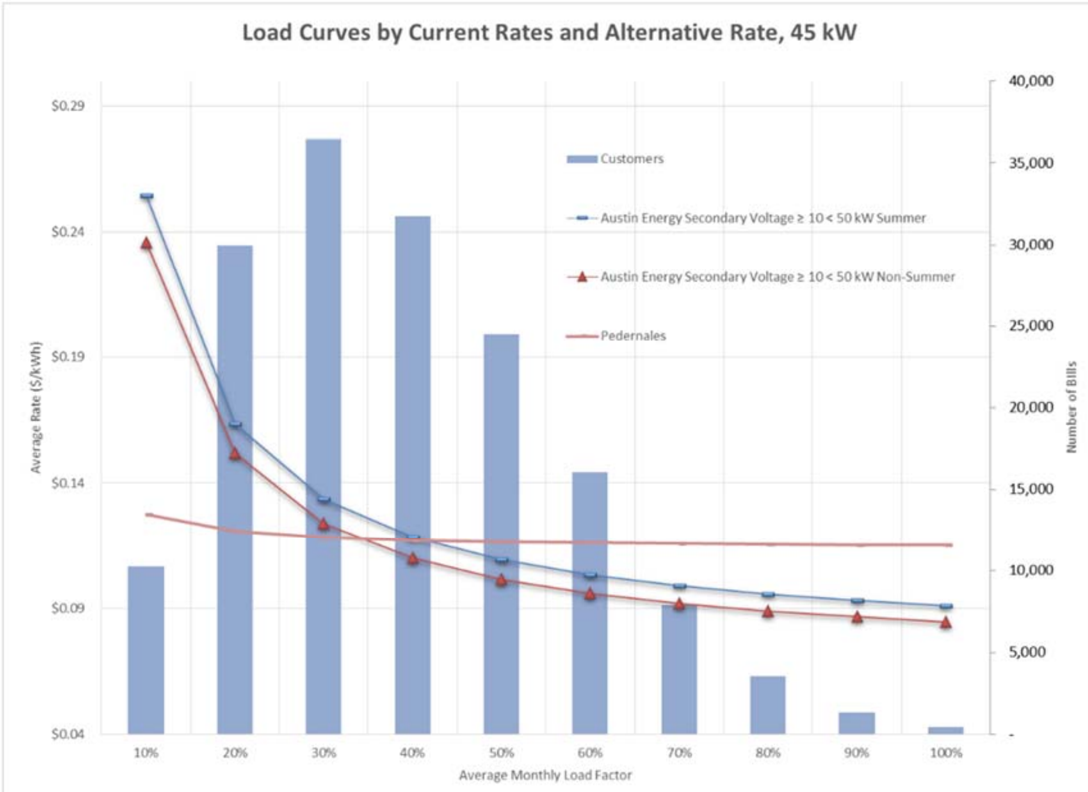


Figure 5-15. PEC Load Curves by Current Rates and Alternative Rate, 45 kW

In all cases, PEC's rate is relatively flat over a range of monthly load factors, which is similar to the BEC rate discussed earlier. Essentially, under the PEC rate structure all customers pay a similar average rate despite potentially large differences in electricity usage and efficiency. As a result, if AE were to adopt the PEC rate structure, high load factor customer monthly bills would increase and low load factor customer bills would decrease. This result is demonstrated in the following table.

Table 5-15
Adjusted PEC Rate Structure Compared to AE's S2 Rate Structure, 15 kW

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	PEC Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
15	10%	1,095	7,523	8.4%	$169.77	$281.78	($112.01)	-39.8%
15	20%	2,190	21,878	33.0%	$294.24	$357.91	($63.68)	-17.8%
15	30%	3,285	22,457	58.2%	$418.70	$434.05	($15.34)	-3.5%
15	40%	4,380	15,811	75.9%	$543.17	$510.18	$32.99	6.5%
15	50%	5,475	10,229	87.4%	$667.64	$586.31	$81.33	13.9%
15	60%	6,570	5,841	94.0%	$792.10	$662.44	$129.66	19.6%
15	70%	7,665	2,622	96.9%	$916.57	$738.57	$178.00	24.1%
15	80%	8,760	1,702	98.8%	$1,041.04	$814.70	$226.33	27.8%
15	90%	9,855	786	99.7%	$1,165.50	$890.84	$274.67	30.8%
15	100%	10,950	283	100.0%	$1,289.97	$966.97	$323.00	33.4%

Approximately 58 percent of S2 customers would experience a rate decrease under the PEC rate structure and 42 percent would experience a rate increase. The PEC rate structure does a poor job of recognizing cost of service principles; therefore, high load factor customers pay too much under this rate structure and subsidize lower load factor customers.

Additionally, with a customer charge and energy rate, there is no mechanism to measure or enforce power factor, so the cost of poor power factor is distributed among customers in the class operating with greater efficiency.

Reliant/CenterPoint

Reliant/CenterPoint is a REP operating throughout the ERCOT competitive retail market. CenterPoint is a Transmission and Distribution provider or TDU. In this example, Reliant and CenterPoint are paired such that Reliant provides the power supply, which is delivered over the CenterPoint transmission and distribution system. While the bundled charges from the Reliant are set competitively, the charges must consider the applicable CenterPoint rate, which is set in a rate making process at the PUCT. Reliant/CenterPoint offers several packages to commercial customers that appear to have similar rate structures with slightly different pricing depending on the term of the customer's commitment or contract with the REP. For the purposes of this analysis, we have selected the Reliant Rockets Secure Advantage 12 plan, which requires a 12-month commitment from the customer. The pricing structure of the plan includes a Usage Charge, Energy Charge, and Delivery Charge. The Delivery Charge is related to CenterPoint's TDU costs as reviewed and approved by the PUCT. Pricing information associated with the Reliant Rockets Secure Advantage 12 plan, indicates the following.

"CenterPoint Energy Delivery Charges include all recurring charges from CenterPoint passed through without markup"

CenterPoint Delivery Charges as approved by the PUCT include customer, demand and energy efficiency charges depending on whether the customer has demand of 10 kW or greater. The following tables summarized the CenterPoint TDU rate structure.

Table 5-16
CenterPoint Delivery Charges

	<10kVA CenterPoint	>10kVA CenterPoint
Customer Charge	$1.64	$2.26
Metering Charge	4.41	18.82
Energy Efficiency Cost Recovery Factor	-	-
Energy Efficiency Cost Recovery Factor – Remand Surcharge	0.0476	2.5781
Advanced Metering Cost Recovery Factor	3.14	3.16
Total Per Month Charges	**$9.2076**	**$26.8181**
Transmission System Charge	$0.004437	$-
Distribution System Charge	0.012218	-
Nuclear Decommissioning Fee	0.000007	-
Transmission Recovery Factor	0.004879	-
Transition Charge (TC1)	-	-
Transition Charge (TC2)	0.002695	0.002695
Transition Charge (TC3)	0.001375	0.001375
Transition Charge (TC5)	0.001302	0.001302
Rate Case Surcharge (RCE-R)	-	-
Storm Recovery Charge	0.001349	-
Storm Recovery Tax Credit	(0.000574)	-
Energy Efficiency Cost Recovery Factor	(0.000097)	0.000601
Total per kWh Charges	**$0.027591**	**$0.005973**
Transmission System Charge		$1.431800
Distribution System Charge		3.059429
Nuclear Decommissioning Fee		0.001828
Transmission Recovery Factor		1.104613
Transition Charge (TC1)		-
Transition Charge (TC2)		-
Transition Charge (TC3)		-
Transition Charge (TC5)		-
Rate Case Surcharge (RCE-R)		-
Storm Recovery Charge		0.099644
Storm Recovery Tax Credit		(0.031644)
Energy Efficiency Cost Recovery Factor		-
Total per kVA Charges		**$5.665670**

In contacting Reliant regarding their treatment of TDU charges, we were told by a customer service representative that Reliant passes through TDU charges in the form of a customer charge and energy rate for all customers regardless of size. If this information is correct, Reliant averages TDU costs incurred by commercial customers and passes these costs to commercial customers in a different manner than the way costs are incurred by the utility. Further, using this approach, we were able to verify an example bill calculation provide on the Reliant Rockets Secure Advantage 12 plan Electricity Facts Label, a label disclosing plan terms and conditions required by the PUCT. With this understanding, the Reliant Rockets Secure Advantage 12 plan rate structure is compared to the AE S2 rate in the following table.

Table 5-17
AE and Reliant/CenterPoint Rate Comparison

Rate Structure Comparison	AE's Secondary Voltage 10kW to 50 kW (S2)	Reliant/ CenterPoint's Rockets Secure Advantage 12 <50 kW	Reliant/ CenterPoint's Rockets Secure Advantage 12 <50kW (Adjusted)
Customer Charge ($/month)			
Base Charge (1)	25.00	9.95	10.27
CenterPoint Customer Charge	N/A	8.52	8.79
Electric Delivery ($/kW billed)	4.00	N/A	N/A
Demand Charge ($/kW billed)			
Summer	6.15	N/A	N/A
Non-Summer	5.15	N/A	N/A
Energy Charge (¢/kWh)			
Summer	2.914	11.498	11.863
Non-Summer	2.414	11.498	11.863
Pass-Throughs (¢/kWh)			
Power Supply Adjustment	3.709	N/A	N/A
Customer Assistance Program	0.065	N/A	N/A
Service Area Street Lighting	0.076	N/A	N/A
Energy Efficiency Services	0.522	N/A	N/A
Regulatory Charge			
(¢/kWh)	N/A	N/A	N/A
($/kW billed)	2.56	N/A	N/A

Notes:
(1) Base Charge does not apply if the customer's monthly energy usage is greater than 800 kWh.

Reliant's Rockets Secure Advantage 12 Plan rate, for the CenterPoint area, does not include a demand charge, though the underlying charges from CenterPoint approved by the PUCT do include demand charges. It is Reliant's choice, as a competitive REP, to restructure its retail rates to exclude a demand charge from the rate structure, as long as Reliant fully compensates CenterPoint for its services.

The adjusted Reliant rate as shown in the above table reflects a prorata adjustment of the rate so that the Reliant rate applied to AE customers served under the S2 rate would generate an equal amount of revenue. In other words, AE would be financially indifferent to either rate as both rates generated the same amount of revenue (although the Reliant rate would not necessarily support the City of Austin's goals and objectives). The analysis supporting this revenue neutral calculation is shown in Exhibit 6 of this report.

Graphical comparisons of Reliant's Rockets Secure Advantage 12 Plan rate compared to AE's S2 rate for customers with monthly maximum demands of 15 kW, 25 kW, and 45 kW are shown in the following graphs.

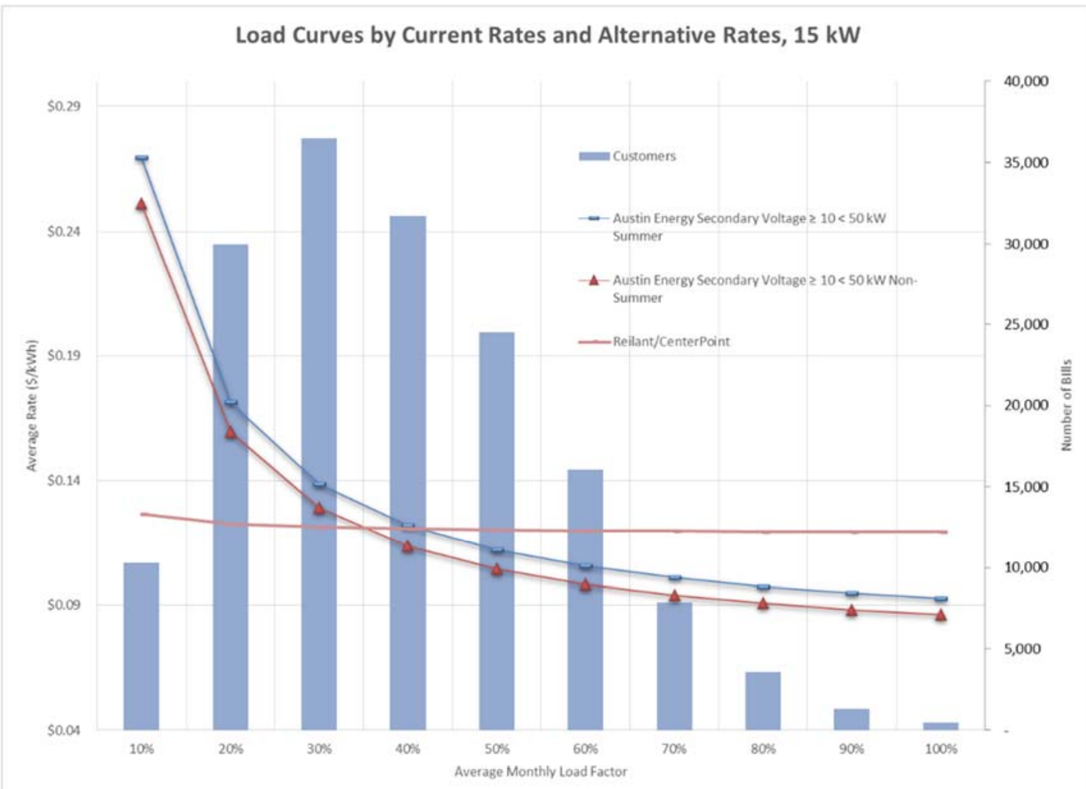


Figure 5-16. Reliant/CenterPoint Load Curves by Current Rates and Alternative Rates, 15 kW

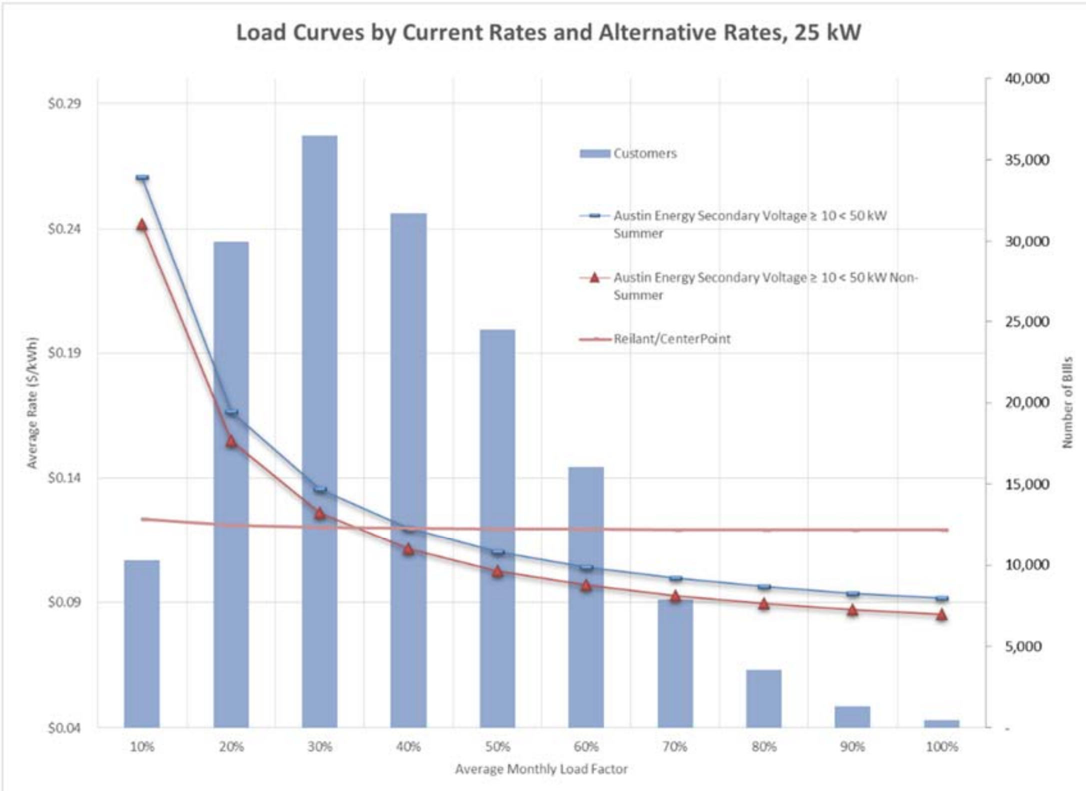


Figure 5-17. Reliant/CenterPoint Load Curves by Current Rates and Alternative Rates, 25 kW

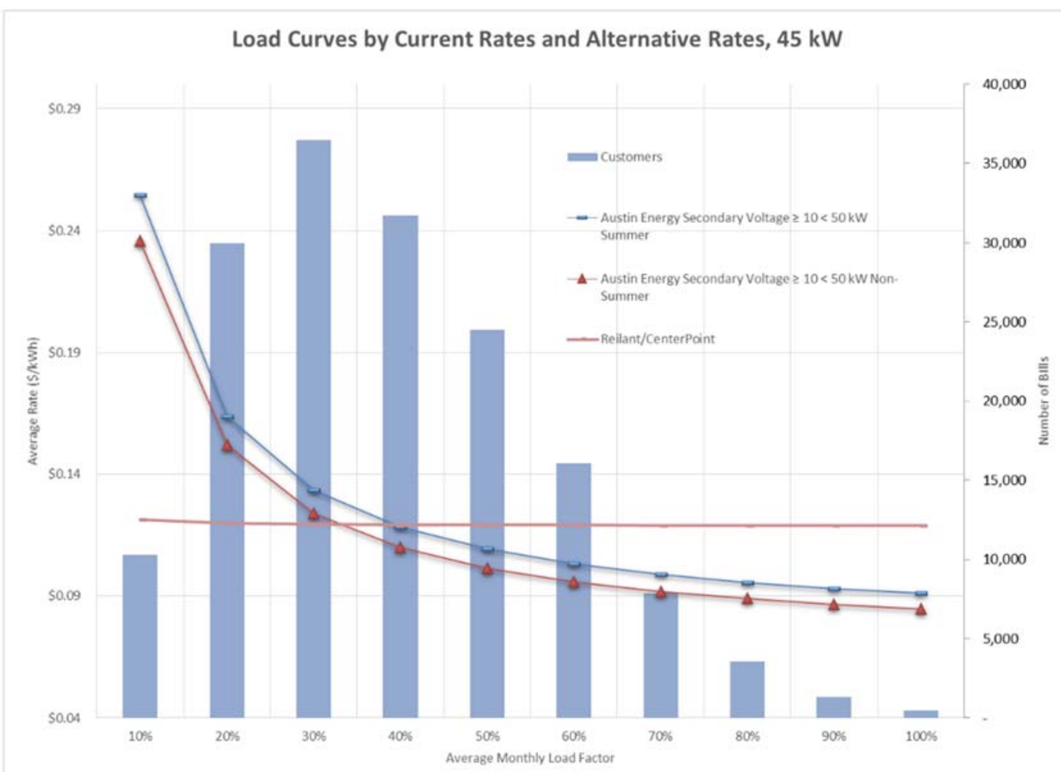


Figure 5-18. Reliant/CenterPoint Load Curves by Current Rates and Alternative Rates, 45 kW

In all cases, Reliant's rate is flat over a range of monthly load factors, which is similar to the BEC and PEC rates discussed earlier. Essentially, under the Reliant rate structure all customers pay a similar average rate despite potentially large differences in electricity usage and efficiency. As a result, if AE were to adopt the Reliant rate structure, high load factor customer monthly bills would increase and low load factor customer bills would decrease. This result is demonstrated in the following table.

Table 5-18
Adjusted Reliant Rate Structure Compared to AE's S2 Rate Structure, 15 kW

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	Reliant Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
15	10%	1,095	7,523	8.4%	$138.69	$281.78	($143.09)	-50.8%
15	20%	2,190	21,878	33.0%	$268.59	$357.91	($89.33)	-25.0%
15	30%	3,285	22,457	58.2%	$398.48	$434.05	($35.56)	-8.2%
15	40%	4,380	15,811	75.9%	$528.38	$510.18	$18.21	3.6%
15	50%	5,475	10,229	87.4%	$658.28	$586.31	$71.97	12.3%
15	60%	6,570	5,841	94.0%	$788.18	$662.44	$125.74	19.0%
15	70%	7,665	2,622	96.9%	$918.08	$738.57	$179.51	24.3%
15	80%	8,760	1,702	98.8%	$1,047.98	$814.70	$233.27	28.6%
15	90%	9,855	786	99.7%	$1,177.87	$890.84	$287.04	32.2%
15	100%	10,950	283	100.0%	$1,307.77	$966.97	$340.80	35.2%

Approximately 58 percent of S2 customers would experience a rate decrease under the Reliant rate structure and 42 percent would experience a rate increase. The rate structure does a poor job of recognizing cost of service principles; therefore, high load factor customers pay too much under this rate structure and subsidize lower load factor customers.

Additionally, the rate structure insulates customers from power factor penalty charges. CenterPoint, as the TDU, bills on a kVa basis. kVa is a measure of "total power" and, therefore, recovers costs appropriately from customers with varying power factors. Although CenterPoint measures kVa for billing purposes, the utility states a power factor requirement greater than or equal to 95 percent. This charge is passed on to Reliant, who apparently averages these costs across all commercial customers it serves.

Sacramento Municipal Utility District

Sacramento Municipal Utility District (SMUD) is a one of the largest public power utilities in the country. SMUD serves about 625,000 customers within its service territory. SMUD's resource mix includes 41 percent from natural gas, 33 percent from renewables, 18 percent from hydroelectric, and 8 percent from miscellaneous other sources. SMUD business objectives include leadership and innovation in the areas of energy efficiency programs, renewable power technologies, and sustainable solutions for a healthier environment.

The applicable SMUD rate structures for the rate structure review are the Small General Service Non-Demand <20 kW and the General Service Demand 20-299 kW rates. The Small General Service Non-Demand <20 kW rate is available to all commercial customers with maximum demands less than 20 kW per billing cycle. General Service Demand 20 kW to 299 kW rate is available to all commercial customers with maximum demand greater than 20 kW but less than 300 kW per billing cycle. A summary of each of these rates is shown in the following table.

Table 5-19
AE and SMUD Rate Comparison

Rate Structure Comparison	AE's Secondary Voltage 10kW to 50kW (S2)	SMUD's Small General Service Non-Demand <20kW	SMUD's Small General Service Demand 20kW to 299kW	SMUD's Small General Service Non-Demand <20kW (Adjusted)	SMUD's Small General Service Demand 20kW to 299kW (Adjusted)
Customer Charge ($/month)	25.00	16.00	23.10	15.95	23.02
Electric Delivery ($/kW billed)	4.00	N/A	N/A	N/A	N/A
Demand Charge ($/kW billed)					
Summer (1)	6.15	N/A	7.14	N/A	7.12
Non-Summer	5.15	N/A	7.14	N/A	7.12
Energy Charge (¢/kWh)					
Summer/ On-peak (2)	2.914	28.52	24.55	28.52	24.47
Non-Summer/ Off-peak (2)	2.414	10.71	8.52	10.71	8.49
Pass-Throughs (¢/kWh)					
Power Supply Adjustment	3.709	N/A	N/A	N/A	N/A
Customer Assistance Program	0.065	N/A	N/A	N/A	N/A
Service Area Street Lighting	0.076	N/A	N/A	N/A	N/A
Energy Efficiency Services	0.522	N/A	N/A	N/A	N/A
Solar Surcharge	N/A	N/A	0.15	N/A	0.15
Power Factor Adjustment (¢/kVar)	N/A	N/A	1.03	N/A	1.03
Regulatory Charge					
(¢/kWh)	N/A	N/A	N/A	N/A	N/A
($/kW billed)	2.56	N/A	N/A	N/A	N/A

Notes:
(1) SMUD Summer season is defined as June – September.
(2) SMUD defines the On-peak period as summer weekdays (excluding the July 4th and Labor Day holidays), from 1500-1800. The off-peak period is all other hours.

SMUD provides service to commercial customers between 10 kW and 50 kW of monthly demand under two different rate structures. SMUD creates a boundary between customers with less than 20 kW of monthly demand (General Service Non-Demand), and customers with 20 kW or greater (General Service Demand). The General Service Non-Demand rate structure does not include a demand charge.

The General Service Demand rate structure includes a demand charge for generation and electric delivery. The adjusted SMUD rate as shown in the table above reflects a prorata adjustment of the rate so that the SMUD rate applied to AE customers served under the S2 rate would generate an equal amount of revenue. In other words, AE would be financially indifferent to either rate as both rates generated the same amount of revenue (although the SMUD rate would not necessarily support the City of Austin's goals and objectives). The analysis supporting this revenue neutral calculation is shown in Exhibit 7 of this report.

Graphical comparisons of SMUD's General Service Non-Demand and General Service Demand rates compared to AE's S2 rate for customers with monthly maximum demands of 15 kW, 25 kW, and 45 kW are shown in the following graphs.

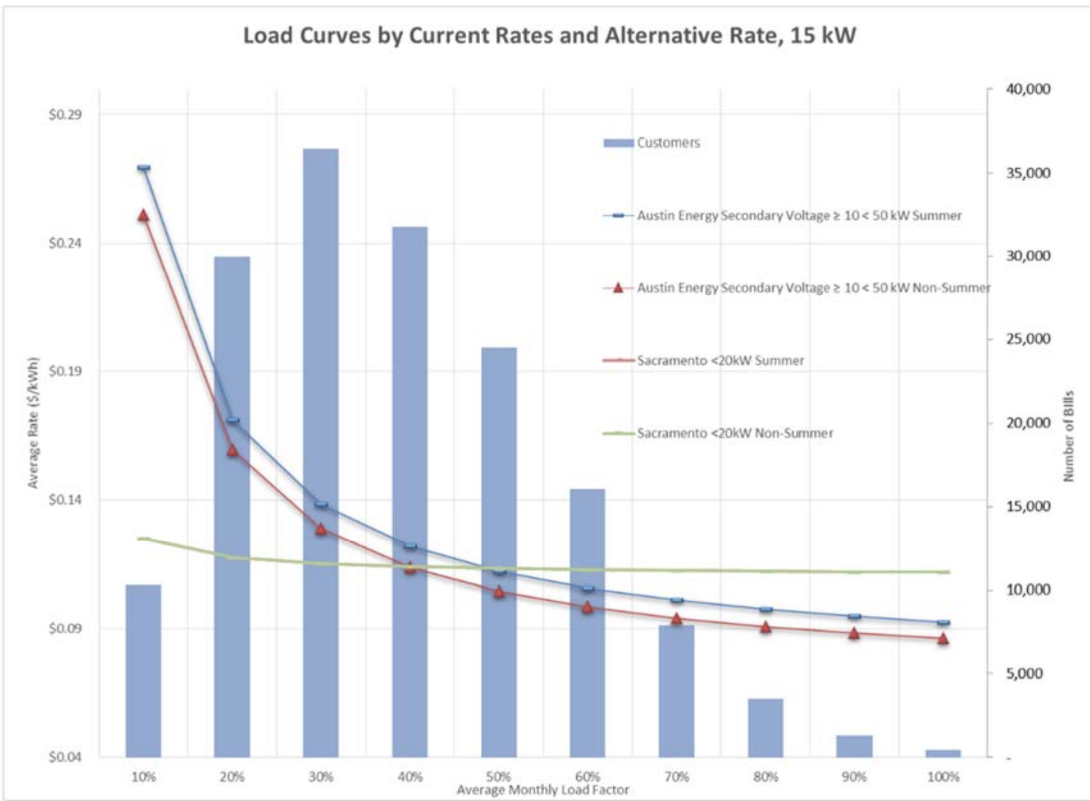


Figure 5-19. SMUD Load Curves by Current Rates and Alternative Rates, 15 kW

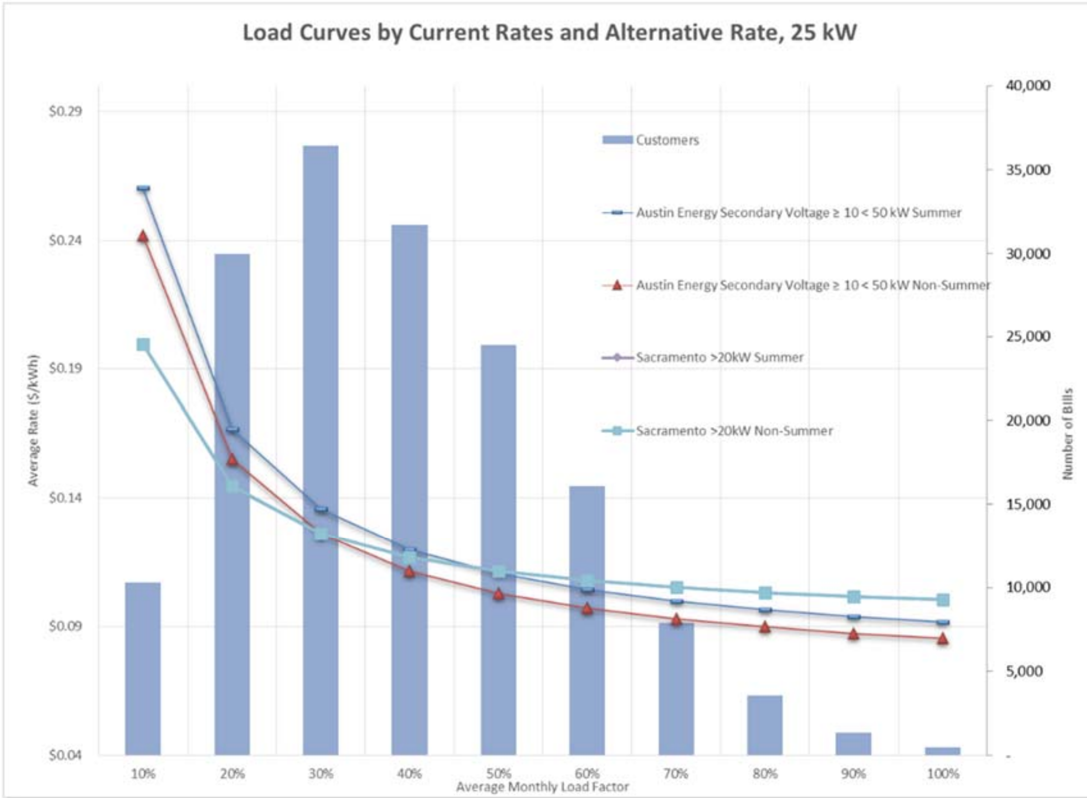


Figure 5-20. SMUD Load Curves by Current Rates and Alternative Rates, 25 kW

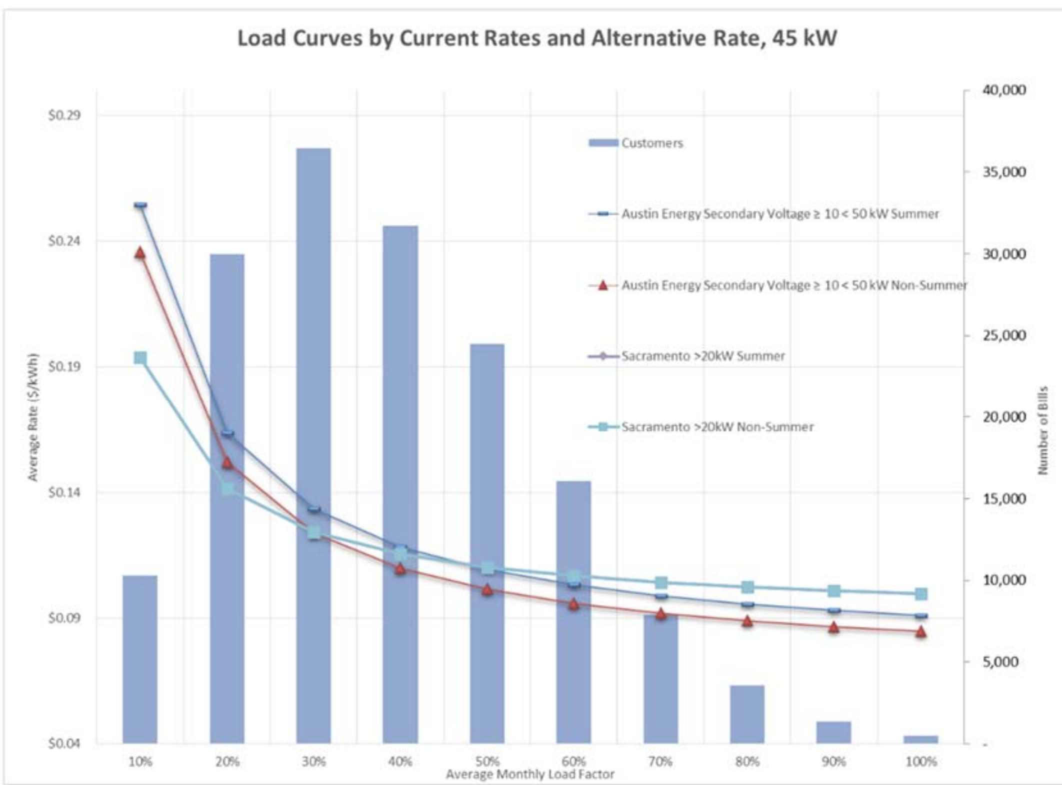


Figure 5-21. SMUD Load Curves by Current Rates and Alternative Rates, 45 kW

In the 15kW example shown above, SMUD's rate structure is flat over a range of monthly load factors, which is similar to the BEC, PEC, and Reliant rates discussed earlier. Essentially, under the SMUD rate structure all customers pay a similar average rate despite large differences in electricity usage and efficiency. As a result, if AE were to adopt the SMUD rate structure, high load factor customer monthly bills would increase and low load factor customer bills would decrease. This result is demonstrated in the following table.

Table 5-20
Adjusted SMUD Rate Structure Compared to AE's S2 Rate Structure, 15 kW

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	SMUD Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
15	10%	1,095	7,523	8.4%	$136.74	$281.78	($145.04)	-51.5%
15	20%	2,190	21,878	33.0%	$257.54	$357.91	($100.38)	-28.0%
15	30%	3,285	22,457	58.2%	$378.33	$434.05	($55.71)	-12.8%
15	40%	4,380	15,811	75.9%	$499.13	$510.18	($11.05)	-2.2%
15	50%	5,475	10,229	87.4%	$619.93	$586.31	$33.62	5.7%
15	60%	6,570	5,841	94.0%	$740.72	$662.44	$78.28	11.8%
15	70%	7,665	2,622	96.9%	$861.52	$738.57	$122.95	16.6%
15	80%	8,760	1,702	98.8%	$982.31	$814.70	$167.61	20.6%
15	90%	9,855	786	99.7%	$1,103.11	$890.84	$212.27	23.8%
15	100%	10,950	283	100.0%	$1,223.91	$966.97	$256.94	26.6%

Approximately 75 percent of S2 customers with demand of less than 20 kW would experience a rate decrease under the SMUD rate structure and 15 percent would experience a rate increase. The absence of a demand charge in the rate structure recovers costs associated with serving low load factor customers from high load factor customers, deviating from cost of service principles.

SMUD's rate structure for customers with a monthly demand of greater than 20 kW includes a customer, demand, and seasonal energy charge. The differential in the seasonal energy charge is significantly greater than the S2 seasonal pricing differential. The demand charge is associated with the production and distribution functions. As a result, when comparing SMUD's bills with AE's S2 rate, there is less of a bill differential. However, bill differentials do exist as the shape of the SMUD rate curve is slightly flatter and the seasonal differentials are greater than that of AE. This flattening of the rate curves shifts costs from low load factor customers to high load factor customers. This result is demonstrated in the following table.

Table 5-21
Adjusted SMUD Rate Structure Compared to AE's S2 Rate Structure, 45 kW

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	SMUD Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
45	10%	3,285	2,424	3.3%	$636.96	$795.35	($158.38)	-19.9%
45	20%	6,570	8,100	14.5%	$930.01	$1,023.74	($93.73)	-9.2%
45	30%	9,855	14,013	33.7%	$1,223.22	$1,252.14	($28.91)	-2.3%
45	40%	13,140	15,937	55.6%	$1,516.44	$1,480.53	$35.91	2.4%
45	50%	16,425	14,284	75.2%	$1,809.65	$1,708.93	$100.73	5.9%
45	60%	19,710	10,219	89.2%	$2,102.87	$1,937.32	$165.55	8.5%
45	70%	22,995	5,262	96.5%	$2,396.09	$2,165.72	$230.37	10.6%
45	80%	26,280	1,843	99.0%	$2,689.30	$2,394.11	$295.19	12.3%
45	90%	29,565	550	99.8%	$2,982.52	$2,622.51	$360.01	13.7%
45	100%	32,850	178	100.0%	$3,275.73	$2,850.90	$424.83	14.9%

Approximately 34 percent of S2 customers with demand greater than 20 kW would experience a rate decrease under the SMUD General Service Demand rate structure and 66 percent would experience a rate increase.

TXU/Oncor

TXU/Oncor is an REP operating in the ERCOT competitive retail market. Oncor is a Transmission and Distribution provider or TDU. In this example, TXU and Oncor are paired such that TXU provides the power supply, which is delivered over the Oncor transmission and distribution system. While the bundled charges from the TXU component are set competitively, the charges must consider the applicable TXU rates as set in a rate making process at the PUCT. TXU/Oncor offers several packages to commercial customers that appear to have similar rate structures with slightly different pricing depending on the term of the customer's commitment or contract with the REP. For the purposes of this analysis, we have selected the TXU Energy Business Monthly Saver 36 plan, which requires a 36-month commitment from the customer. The pricing structure of the plan includes a Base Charge, Energy Charge, and Delivery Charge. The Delivery Charge is related to Oncor's TDU costs as reviewed and approved by the PUCT. Pricing information associated with the TXU Energy Business Monthly Saver 36 plan, indicates the following.

"Transmission and Distribution Utility (TDU) Charges for delivering electricity will be passed through to customer with no increase or markup. For updated TDU delivery charges factors go to txu.com/tduchargesbiz."

Oncor Delivery Charges as approved by the PUCT include customer, demand and energy efficiency charges depending on whether the customer has demand of 10 kW or greater. The following tables summarized the Oncor TDU rate structure.

Table 5-22
Oncor Deliver Charges

	<10kW Oncor	>10kW Oncor
Customer Charge	$1.71	$6.80
Metering Charge	5.19	22.14
Energy Efficiency Cost Recovery Factor	-	-
Energy Efficiency Cost Recovery Factor – Remand Surcharge	-	-
Advanced Metering Cost Recovery Factor	2.39	3.98
Total Per Month Charges	**$9.29**	**$32.92**
Transmission System Charge	$-	$-
Distribution System Charge	0.020109	-
Nuclear Decommissioning Fee	0.000146	-
Transmission Recovery Factor	0.006736	-
Transition Charge (TC1)	0.000480	-
Transition Charge (TC2)	0.000798	-
Transition Charge (TC3)	-	-
Transition Charge (TC5)	-	-
Rate Case Surcharge (RCE-R)	0.000067	-
Storm Recovery Charge	-	-
Storm Recovery Tax Credit	-	-
Energy Efficiency Cost Recovery Factor	0.000437	0.000525
Total per kWh Charges	**$0.028773**	**$0.000525**
Transmission System Charge		$-
Distribution System Charge		4.380000
Nuclear Decommissioning Fee		0.044000
Transmission Recovery Factor		3.481646
Transition Charge (TC1)		0.172000
Transition Charge (TC2)		0.267000
Transition Charge (TC3)		-
Transition Charge (TC5)		-
Rate Case Surcharge (RCE-R)		0.011400
Storm Recovery Charge		-
Storm Recovery Tax Credit		-
Energy Efficiency Cost Recovery Factor		-
Total per kW Charges		**$8.356046**

Based on the information we have been able to gather, it appears that TXU does pass through the Oncor rate structure directly to customers without modification, which is a very different pricing approach than the example from the Reliant REP presented earlier. Similar to our verification of the Reliant/Oncor rate structure, we verified an example bill calculation provided on the TXU Energy Business Monthly Saver 36 plan Electricity Facts Label, a label disclosing plan terms and conditions required by the PUCT. This analysis confirmed that the Oncor TDU rate is passed through to customers without modification to its rate structure.

With this understanding, the TXU Energy Business Monthly Saver 36 plan rate structure is compared to the AE S2 rate in the following table.

Table 5-23
AE and TXU/Oncor Rate Comparison

Rate Structure Comparison	AE's Secondary Voltage 10kW to 50kW (S2)	TXU/Oncor's Energy Business Monthly Saver 36 <50kW	TXU/Oncor's Energy Business Monthly Saver 36 <50kW (Adjusted)
Customer Charge ($/month)	25.00	N/A	N/A
Base Charge	N/A	9.95	9.10
Oncor Base Charge	N/A	32.92	30.11
Electric Delivery ($/kW billed)	4.00	N/A	N/A
Demand Charge ($/kW billed)			
Summer	6.15	8.36	7.64
Non-Summer	5.15	8.36	7.64
Energy Charge (¢/kWh)			
Summer	2.914	N/A	N/A
Non-Summer	2.414	N/A	N/A
TXU Energy Charge	N/A	9.20	8.41
Oncor Energy Charge	N/A	0.05	0.05
Pass-Throughs (¢/kWh)			
Power Supply Adjustment	3.709	N/A	N/A
Customer Assistance Program	0.065	N/A	N/A
Service Area Street Lighting	0.076	N/A	N/A
Energy Efficiency Services	0.522	N/A	N/A
Regulatory Charge			
(¢/kWh)	N/A	N/A	N/A
($/kW billed)	2.56	N/A	N/A

TXU's Energy Business Monthly Saver 36 rate, in the Oncor service area, for commercial customers between 10 kW and 50 kW of monthly demand consists of a customer, demand, and energy charge.

The adjusted TXU rate as shown in the table above reflects a prorata adjustment of the rate so that the TXU rate applied to AE customers served under the AE S2 rate would generate an equal amount of revenue. In other words, AE would be financially indifferent to either rate as both rates generated the same amount of revenue (although the TXU rate would not necessarily support the City of Austin's goals and objectives). The analysis supporting this revenue neutral calculation is shown in Exhibit 8 of this Report.

Graphical comparisons of TXU's Energy Business Monthly Saver 36 rate compared to AE's S2 rate for customers with monthly maximum demands of 15kW, 25kW, and 45kW are shown in the following graphs.

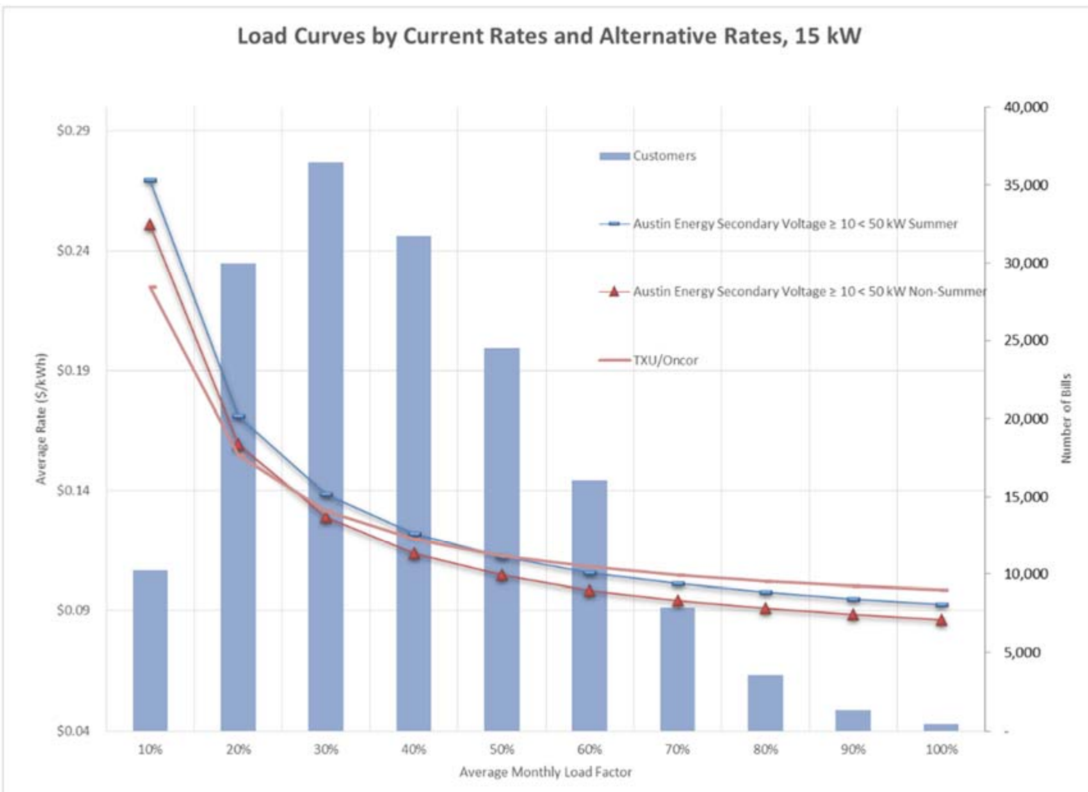


Figure 5-22. TXU/Oncor Load Curves by Current Rates and Alternative Rates, 15 kW

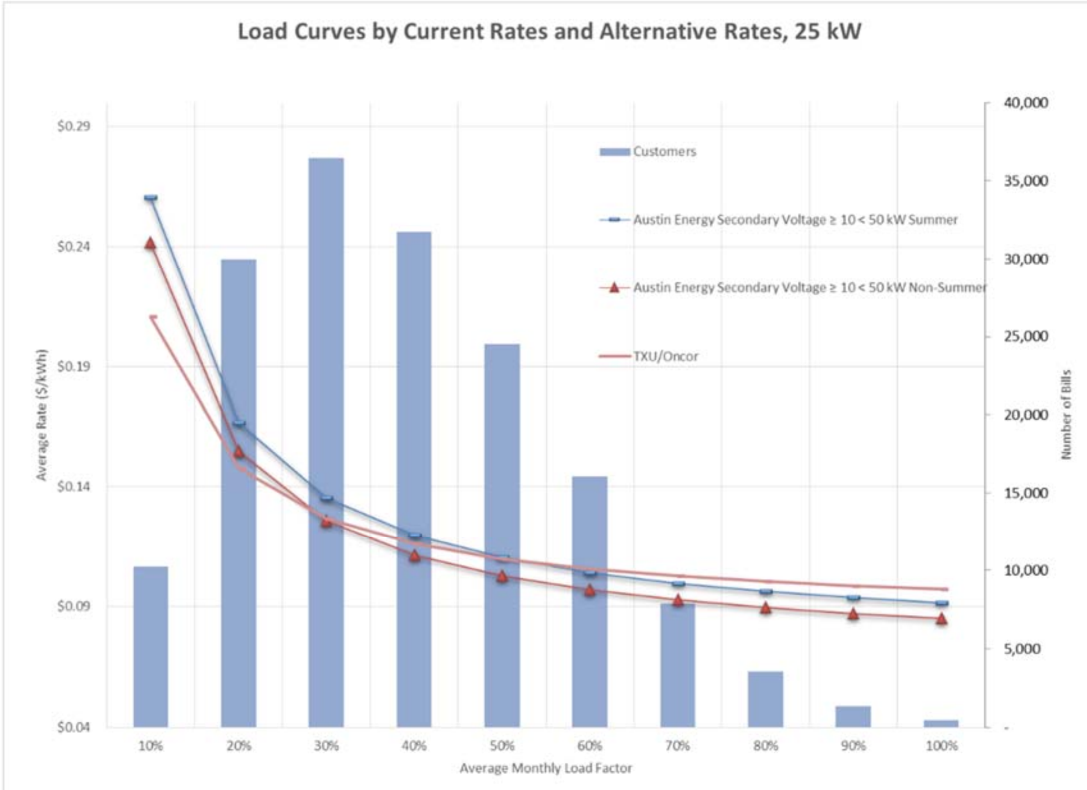


Figure 5-23. TXU/Oncor Load Curves by Current Rates and Alternative Rates, 25 kW

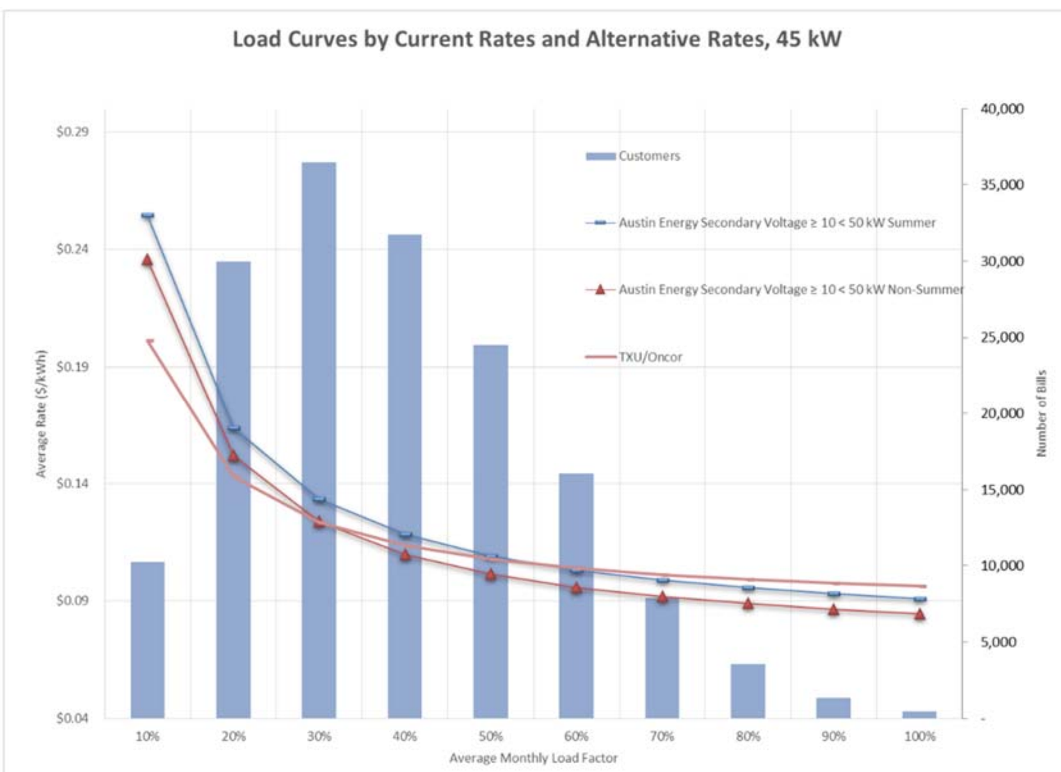


Figure 5-24. TXU/Oncor Load Curves by Current Rates and Alternative Rates, 45 kW

In all cases, TXU's rate structure is similar to AE's S2 rate structure. However, bill differentials do exist as the shape of the TXU/Oncor rate curve is slightly flatter than that of AE. This flattening of the rate curves shifts costs from low load factor customers to high load factor customers. This result is demonstrated in the following table.

Table 5-24
Adjusted Oncor Rate Structure Compared to AE's S2 Rate Structure, 15 kW

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	TXU Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
15	10%	1,095	7,523	8.4%	$246.48	$281.78	($35.30)	-12.5%
15	20%	2,190	21,878	33.0%	$339.13	$357.91	($18.78)	-5.2%
15	30%	3,285	22,457	58.2%	$431.78	$434.05	($2.26)	-0.5%
15	40%	4,380	15,811	75.9%	$524.44	$510.18	$14.26	2.8%
15	50%	5,475	10,229	87.4%	$617.09	$586.31	$30.78	5.2%
15	60%	6,570	5,841	94.0%	$709.74	$662.44	$47.30	7.1%
15	70%	7,665	2,622	96.9%	$802.39	$738.57	$63.82	8.6%
15	80%	8,760	1,702	98.8%	$895.04	$814.70	$80.34	9.9%
15	90%	9,855	786	99.7%	$987.70	$890.84	$96.86	10.9%
15	100%	10,950	283	100.0%	$1,080.35	$966.97	$113.38	11.7%

Approximately 58 percent of S2 customers would experience a rate decrease under the TXU rate structure and 42 percent would experience a rate increase. However, since the rate structures are somewhat similar, the magnitude of the differences is relatively small. The TXU rate structure mitigates the cost recovery of capacity based costs from poor load factor customers. The TXU/Oncor rate structure for customers with a demand greater than 10 kW is similar to AE's current S2 rate.

The TXU's Energy Business Monthly Saver 36 rate, for the Oncor service area, includes a demand and energy charge, directly passing through the Oncor rate for delivery service. The TXU/Oncor demand and energy rate structure differs from Reliant's Rockets Secure Advantage 12 Plan rate, for the CenterPoint area, which does not include a demand charge, though the underlying charges from CenterPoint approved by the PUCT do include demand charges. It is the REP's choice, as a competitive REP, to restructure its retail rates to include or exclude demand charges from its rate structure, as long as REP fully compensates the delivery providers (CenterPoint and Oncor in the examples provided) for its services.

Conclusions

Based on our benchmarking analyses, we conclude the following:

- For small commercial customers, there is no standard approach in determining commercial class size. Commercial class sizes range significantly between utilities.

- AE's S1 and S2 customer class boundary is the same as TDU's in ERCOT and consistent with TDU rates set by the PUCT. This result is intentional based on one of the justifications for the current class boundaries given in the 2011 Rate Study.
- When comparing rate design for commercial customers in AE's S1, S2, and S3 customer classes with other utilities, there is no standard rate design approach.
  - Customer class sizes range significantly between utilities. Most utilities, but not all, have small commercial classes that do not have a demand charge and larger commercial classes with a demand charge. For customers with maximum monthly demands between 0 kW to 50 kW, utilities with small commercial classes without a demand charge include in our benchmarking review are as follows:
    - BEC – Basic <50 kW
    - FCU – General Service <25 kW
    - PEC – Small Power < 75 kW
    - Reliant/CenterPoint
    - SMUD – General Service Non-Demand <20 kW
    - TXU/Oncor < 10kW
  - Two utilities, CPS and LADWP have demand charges, or similar charges, applicable to all commercial customers regardless of size.
  - Three utilities, BEC, PEC, and Reliant/CenterPoint do not apply demand charges to any small commercial customers with maximum demands between 0 kW to 50 kW.
- For S2 customers, with demands ranging from 10 kW to 50 kW, benchmarking results indicate that there is no uniform approach to rate design. Of the eight utilities included in the benchmarking study:
  - Three utilities do not have a demand, or similar, charge for customers with maximum monthly demands between 10 kW and 50 kW.
  - Three utilities do have a demand, or similar, charge for customers with maximum monthly demands between 10 kW and 50 kW.
  - Two utilities have rate boundaries within this range where customers below the boundary do not have a demand, or similar, charge and customer above the boundary have a demand, or similar, charge.
- For S2 customers, with demand ranging from 10 kW to 20 kW, benchmarking results indicate that there is no uniform approach to rate design. Of the eight utilities included in the benchmarking study:
  - Five utilities do not have a demand, or similar, charge for customers with maximum monthly demands between 10 kW and 20 kW.
  - Three utilities do have a demand, or similar, charge for customers with maximum monthly demands between 10 kW and 20 kW.

- All things considered, AE's current S2 rate structure impacts all customers in the class (10 kW - 50 kW) in a similar manner as that of CPS Energy, LADWP, and TXU/Oncor (as well as SMUD for some S2 customers). It is worth noting that CPS Energy has a rate mechanism in place to shield low load factor customers from significant bill impacts, which is something that does not currently exist in the S2 rate structure.
- If AE were to adopt a rate structure similar to most utilities included in this benchmarking analysis, the most likely result would be a shift of costs from low load factor customers to high load factor customers. This shift does not align with the intent of rates objectives adopted by the Austin City Council in 2012.

Section 6
RATE STRUCTURE SENSITIVITY

As described in Section 5 – Rate Benchmarking of this Report, if AE were to adopt another utility's rate structure, costs would shift between customers. In fact, any deviation from the existing rate structure will shift costs from one group of customers to another. To help AE understand the magnitude of cost shifting on customers within the class under various rate change scenarios, NewGen has made generic modifications to the S2 rate in order to evaluate the impact of these rate design changes on customers within the class. The rates presented within this Section are for illustrative purposes only and NewGen does not recommend these modifications to the existing S2 rate design.

Sensitivity Analysis of S2 Rate Structure

For comparison purposes, we have developed two rate sensitivity analyses as examples of expected cost shifting and corresponding customer impacts within the S2 customer class. In both sensitivity cases, rate structure adjustments generate the same amount of revenue as the current S2 rate, making the scenarios presented revenue neutral. The scenarios developed for this sensitivity analysis are not intended to serve as alternative rates, but to simply analyze the effect of rate structure changes on the S2 class. The rate structure changes implemented in this sensitivity analysis are:

1. Sensitivity Analysis 1 – Remove the Demand Charge. Therefore, the rate structure is comprised of a Customer and an Energy Charge, including pass-through charges.
2. Sensitivity Analysis 2 – Reduced Demand Charge by one-half, from the current S2 Demand Charge. Therefore, the rate structure is comprised of a Customer, lower Demand Charge, and higher Energy Charge, including pass-through charges.

Sensitivity Analysis 1, with no demand charge, results in a flat rate curve compared to the current S2 rate. The rate design yields an average rate of about $0.14 per kWh for all customers in the class. Table 6-1 details the effect that transitioning the current S2 rate structure to a rate structure with no demand charge would have on a S2 customer's monthly bill. As shown in the table below, the modeled monthly bills are representative of an S2 customer with a 15 kW monthly demand.

Table 6-1
Sensitivity Analysis 1 (SA1) of AE's S2 Rate Structure, 15 kW

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	SA1 Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
15	10%	1,095	7,523	8.4%	$152.80	$281.78	($128.98)	-45.8%
15	20%	2,190	21,878	33.0%	$280.61	$357.91	($77.30)	-21.6%
15	30%	3,285	22,457	58.2%	$408.41	$434.05	($25.63)	-5.9%
15	40%	4,380	15,811	75.9%	$536.22	$510.18	$26.04	5.1%
15	50%	5,475	10,229	87.4%	$664.02	$586.31	$77.72	13.3%
15	60%	6,570	5,841	94.0%	$791.83	$662.44	$129.39	19.5%
15	70%	7,665	2,622	96.9%	$919.63	$738.57	$181.06	24.5%
15	80%	8,760	1,702	98.8%	$1,047.44	$814.70	$232.74	28.6%
15	90%	9,855	786	99.7%	$1,175.24	$890.84	$284.41	31.9%
15	100%	10,950	283	100.0%	$1,303.05	$966.97	$336.08	34.8%

The graph provided in Figure 6-1, illustrates the current S2 rate structure, the SA1 rate structure, and S1 (Secondary Voltage less than 10 kW) rate structure. The S1 rate structure has been included for comparison purposes.

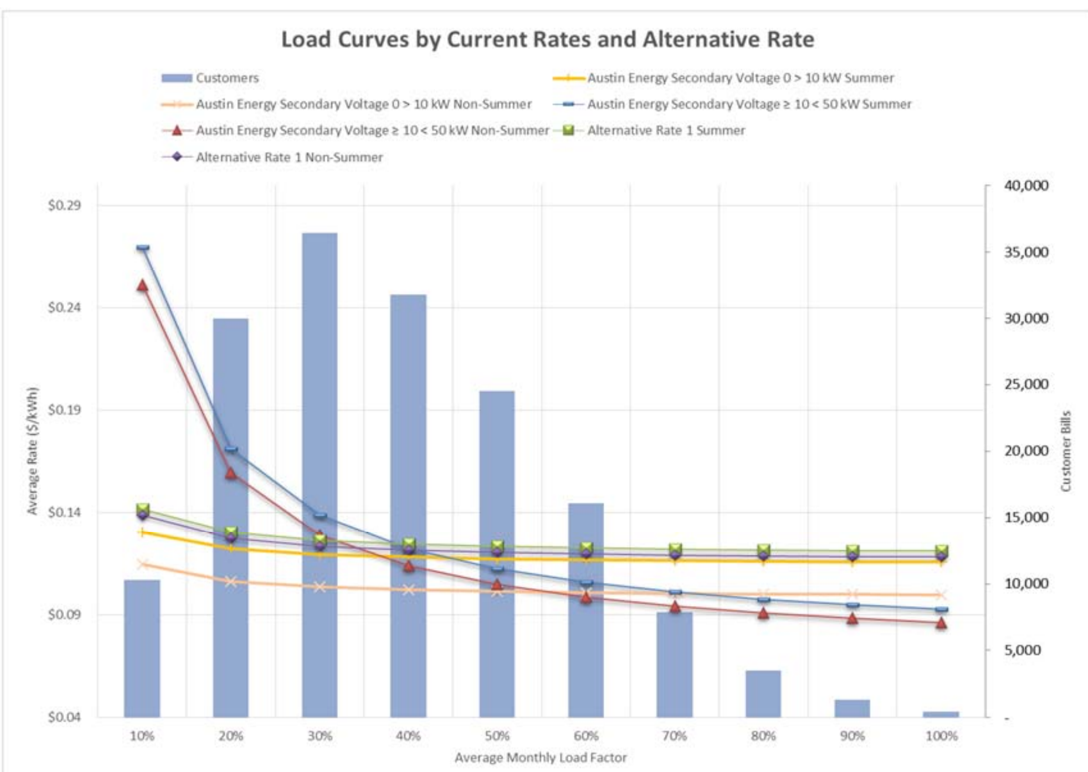


Figure 6-1. Load Curves by Current Rates and Sensitivity Analysis 1

This rate structure significantly shifts costs from low load factor customers to high load factor customers. Although overall rate revenues align with the class cost of service results, this structure does a poor job of equitably recovering costs from customers within the class and does not align with the rate design goals and objectives stated in the 2011 Rate Study.

Sensitivity Analysis 2, with a lower demand charge, retains a similar rate curve as the S2 rate but with a more gradual and less severe impact on low load factor customers. Placing a greater importance on the volume of energy used by the customer and reducing the cost associated with demand results in a cost shift from low load factor customers to high load factor customers, but to a lesser degree than Sensitivity Analysis 1. The variance in cost per kWh across S2 customer load factors range from $0.19 per kWh to $0.11 per kWh. Such an approach retains some, but not all of, the price signal related to demand and power factor.

Table 6-2 details the effect that transitioning the current S2 rate structure to a rate structure with a lower demand charge would have on a S2 customer's monthly bill. As shown in the table below, the modeled monthly bills are representative of an S2 customer with a 15 kW monthly demand.

Table 6-2
Sensitivity Analysis 2 (SA2) of AE's S2 Rate Structure, 15 kW

Billed Demand (kW)	Monthly Load Factor	Billed Energy (kWh)	Number of Bills for Demand	Number of Bills (% of Total)	SA2 Rate Structure	AE Rate Structure	Difference ($)	Difference (%)
15	10%	1,095	7,523	8.4%	$217.29	$281.78	($64.49)	-22.9%
15	20%	2,190	21,878	33.0%	$319.26	$357.91	($38.65)	-10.8%
15	30%	3,285	22,457	58.2%	$421.23	$434.05	($12.82)	-3.0%
15	40%	4,380	15,811	75.9%	$523.20	$510.18	$13.02	2.6%
15	50%	5,475	10,229	87.4%	$625.17	$586.31	$38.86	6.6%
15	60%	6,570	5,841	94.0%	$727.13	$662.44	$64.69	9.8%
15	70%	7,665	2,622	96.9%	$829.10	$738.57	$90.53	12.3%
15	80%	8,760	1,702	98.8%	$931.07	$814.70	$116.37	14.3%
15	90%	9,855	786	99.7%	$1,033.04	$890.84	$142.20	16.0%
15	100%	10,950	283	100.0%	$1,135.01	$966.97	$168.04	17.4%

The graph provided in Figure 6-2, illustrates the current S2 rate structure, the SA2 rate structure, and S1 rate structure. The S1 rate structure has been included for comparison purposes.

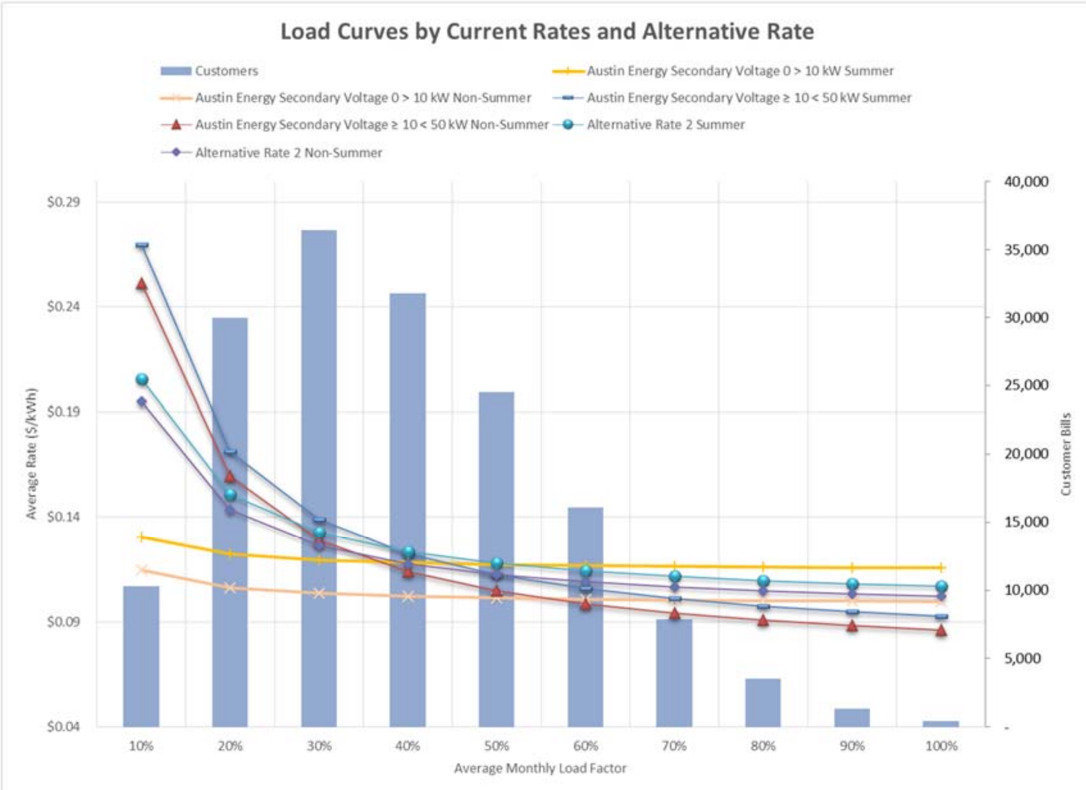


Figure 6-2. Load Curves by Current Rates and Sensitivity Analysis 2

Based on these sensitivity analyses, NewGen has demonstrated that by removing or reducing the demand charge in the S2 rate, the variation in the rate per kWh will be reduced for S2 customers regardless of customer's energy usage or efficiency; however, with this reduction in price per kWh differential the correlation of cost to serve customers will be reduced as well. It is NewGen's understanding that AE's goal is to encourage customers to utilize the system efficiently, and recover costs from customers in alignment with cost causation. By removing or reducing the demand component of the current rate structure, low load factor S2 customers will experience rate relief and cost will be shifted to high load factor customers. Under this type of rate structure, the alignment of the rates with cost of service results will be minimized or lost.

Change to Customer Class

Currently the S2 rate is applied to customers with a demand between 10 kW and 50 kW. NewGen evaluated the cost of AE transitioning S2 customers with a demand between 10 kW and 20 kW to the current S1 rate. Based on NewGen's analyses, transitioning customers with a demand between 10 kW and 20 kW to the S1 rate is projected to reduce AE's revenues by approximately $6.5 million per year, or a reduction of approximately 18 percent of revenue from these customers. If AE desires to remain revenue neutral as a result of such a change, S1 class rates would need to be adjusted to recover this lost revenue.

As mentioned earlier in this Report, load factor, not customer size (within the bandwidth of 10 kW to 50 kW), is a primary driver of average cost. Also, it is important to recognize that "small, local" businesses are not confined to a narrow range of demands (e.g., 10 kW to 20 kW). In fact, some of these businesses exhibit much larger demands in their operations. Thus, if the objective is to support the small, local business community in Austin, altering the rate for customers in a narrow range of demands will be an imprecise means to achieve this policy goal and many of the intended beneficiaries of such a policy would not be assisted by this change. Other support, such as energy audits or efficiency investment subsidies, could be more targeted to the intended recipients and, thus, would likely achieve a much better outcome.

Conclusion

Based on our review of hypothetical rate changes to the S2 customer class, we conclude the following.

- Any rate change that reduces or eliminates the current S2 demand charge will shift costs from low load factor customers to high load factor customers.
- Shifting costs from low load factor customers to high load factor customers does not agree with the cost of service results of the 2011 Rate Study.
- Shifting costs from low load factor customers to high load factor customers does not align with the rate design objectives of the 2011 Rate Study.

Section 7
RECOMMENDATIONS

Based on our analyses as described herein, we recommend the following:

- AE should update detailed customer usage information for the S2 class, gathered and analyzed in this study, which should be incorporated into AE's next cost of service study.
- AE should perform a detailed multi-year weather normalization study for the S2 class to clearly understand the influence of the current rate structure on customer electricity consumption patterns.
- To the extent possible, AE should maintain current pricing signals as they reflect cost of service results and customer reactions to these signals generally appear to be meeting the utility's rate design objectives.
- AE should consider options to minimize "rate shock" for low load factor and poor power factor customers.
- In the short term, for S2 customers, AE may consider temporarily rolling back the power factor penalty charge from 90 percent to 85 percent until the next comprehensive rate review. This adjustment would reduce power factor penalty revenues for customers in the S2 class by approximately 54 percent. The reduction in revenue, of approximately $400,000 per year, would be absorbed by AE and not recovered elsewhere. It is important to note that this would not be a change supported by cost of service principles but, rather, it would serve as a policy decision to mitigate bill impacts for certain poor power factor customers. This strategy would provide rate relief to less than 200 customers with poor power factors. These customers currently experience an increase in their demand charges of 29 percent or greater over their pre-2012 bills.
- In the long term, AE could consider modifications to the existing rate structure that would limit the amount a low load factor and/or poor power factor customer would pay (on an average rate basis). A limit can be applied to the rate structure without undermining important demand pricing signals embedded in the current rate structure and deviating from cost of service results. Such a limit may result in a subsidy that must be borne by other customers in the class; therefore, the size and breadth of the cap must meet AE policy objectives. This strategy would minimize the amount of subsidy and target the subsidy more directly to low load factor and poor power factor customers. Once such modifications are made, we recommend that the power factor penalty charge for this class of customers be reinstated to the same level as for other AE customer classes (if it was reduced as a short term mitigation measure).
- A comprehensive cost of service analysis should be conducted in advance of a long-term strategy so that rate structure modifications properly consider the true cost of serving the lowest load factor customers in the S2 customer class.

EXHIBIT 1
Rate Benchmarking Analysis - BEC

Austin Energy
Rate Benchmarking Analysis
Exhibit 1 - BEC

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Proof of Revenue						
		Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL)			**Austin Energy Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
1								
2	**Austin Energy Rate Schedule**							
3								
4	**Customer Charge (months)**	**138,187**	**$ 25.00**	**$ 3,454,675**	**24,077**	**$ 25.00**	**$ 601,925**	**$ 4,056,600**
5								
6	Demand Charges							
7	Winter ($/kW-billed)	1,877,111	$ 5.15	9,667,124	339,867	$ 5.12	1,740,119	11,407,243
8	Summer ($/kW-billed)	1,012,365	$ 6.15	6,226,042	164,792	$ 6.11	1,006,881	7,232,923
9	Subtotal Demand Charges		$ 5.48	$ 15,893,166		$ 5.45	$ 2,747,000	$ 18,640,166
10								
11	Electric Delivery ($/kW-billed)	2,889,476	$ 4.00	11,557,904	504,659	$ 3.98	2,008,544	13,566,448
12	Regulatory Charge ($/kW)	2,889,476	$ 2.56	7,397,059	504,659	$ 2.56	1,291,928	8,688,986
13	Temporary Supplemental Charge (OCL)	2,889,476	$ -	-	504,659	$ 0.13	65,606	65,606
14	**Subtotal Demand Charges and Adjustment Charges**		**$ 6.56**	**$ 34,848,129**		**$ 12.12**	**$ 6,113,077**	**$ 40,961,206**
15								
16	Energy Charge (kWh)							
17	Winter Energy (kWh)	433,209,672	$ 0.02414	10,457,681	70,674,283	$ 0.02399	1,695,476	12,153,158
18	Summer Energy (kWh)	307,959,288	$ 0.02914	8,973,934	46,783,352	$ 0.02896	1,354,846	10,328,780
19	Subtotal Energy Charge		$ 0.02581	$ 19,431,615		$ 0.02565	$ 3,050,322	$ 22,481,937
20								
21	FAC or PSA (kWh)	741,168,960	$ 0.03709	27,489,957	117,457,635	$ 0.03709	4,356,504	31,846,460
22	Customer Assistance Program ($/kWh)	741,168,960	$ 0.00065	481,760	117,457,635	$ 0.00065	76,347	558,107
23	Service Area Street Lighting ($/kWh)	741,168,960	$ 0.00076	563,288	117,457,635	$ -	-	563,288
24	Energy Efficiency Services ($/kWh)	741,168,960	$ 0.00522	3,868,902	117,457,635	$ 0.00522	613,129	4,482,031
25	Transmission Service Adjustment	741,168,960	$ -	-	117,457,635	$ -	-	-
26	**Subtotal Energy Charge and Adjustment Charges**		**$ 0.06953**	**$ 51,835,522**		**$ 0.06861**	**$ 8,096,302**	**$ 59,931,824**
27								
28	**TOTAL Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
29	*Check*							
30	**Summary of Revenue**							
31	Customer Charge			$ 3,454,675			$ 601,925	$ 4,056,600
32	Demand Charge			34,848,129			6,113,077	40,961,206
33	Energy Charge			51,835,522			8,096,302	59,931,824
34	**Total Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
35	*Check*							
36								
37								

Austin Energy
Rate Benchmarking Analysis
Exhibit 1 - BEC

(A)	(B)	(J)		(K)		(L)	(M)		(N)		(O)		(P)
		BEC Structure w AE Revenue Requirement											
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)					**Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)**						**Total Bluebonnet Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**		**Rate**		**Revenues**	**Billing Units**		**Rate**		**Revenues**		**Total Revenues**
38	**BEC Rate Schedule**												
39													
40	**Customer Charge (months)**	**138,187**	**$**	**54.64**	**$**	**7,549,858**	**24,077**	**$**	**54.64**	**$**	**1,315,449**	**$**	**8,865,307**
41													
42	**Demand Charge (kW)**	**2,889,476**	**$**	**-**	**$**	**-**	**504,659**	**$**	**-**	**$**	**-**	**$**	**-**
43													
44													
45	Energy Charge (kWh)												
46	Energy Charge (kWh)	741,168,960	$	0.07056	$	52,294,538	117,457,635	$	0.07056	$	8,287,439	$	60,581,977
47	Subtotal Energy Charges				$	52,294,538				$	8,287,439	$	60,581,977
48													
49	Power Cost Recovery Factor (PCRF)	741,168,960	$	0.00109	$	809,877	117,457,635	$	0.00109		128,346	$	938,223
50	Distribution Charge - three phase (kWh)	741,168,960	$	0.04026	$	29,835,851	117,457,635	$	0.04026		4,728,272	$	34,564,124
51	**Subtotal Energy Charges and Adjustment Charges**				**$**	**82,940,266**				**$**	**13,144,058**	**$**	**96,084,323**
52													
53	**TOTAL Revenue**				**$**	**90,490,124**				**$**	**14,459,506**	**$**	**104,949,630**
54													
55	**Summary of Revenue**												
56	Customer Charge				$	7,549,858				$	1,315,449	$	8,865,307
57	Demand Charge					-					-		-
58	Energy Charge					82,940,266					13,144,058		96,084,323
59	**Total Revenue**				**$**	**90,490,124**				**$**	**14,459,506**	**$**	**104,949,630**
60	*Check*												

Austin Energy
Rate Benchmarking Analysis
Exhibit 1 - BEC

(A) Line No.	(B) Item	(Q) Billing Units		(R) Rate		(S) Revenues	(T) Billing Units		(U) Rate		(V) Revenues		(W) Total Revenues
		BEC Structure w BEC Revenue Requirement											
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)					**Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)**						**Total Bluebonnet Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
38	**BEC Rate Schedule**												
39													
40	**Customer Charge (months)**	**138,187**	**$**	**50.00**	**$**	**6,909,350**	**24,077**	**$**	**50.00**	**$**	**1,203,850**	**$**	**8,113,200**
41													
42	**Demand Charge (kW)**	**2,889,476**	**$**	**-**	**$**	**-**	**504,659**	**$**	**-**	**$**	**-**	**$**	**-**
43													
44													
45	Energy Charge (kWh)												
46	Energy Charge (kWh)	741,168,960	$	0.06457	$	47,858,021	117,457,635	$	0.06457	$	7,584,357	$	55,442,378
47	Subtotal Energy Charges				$	47,858,021				$	7,584,357	$	55,442,378
48													
49	Power Cost Recovery Factor (PCRF)	741,168,960	$	0.00100	$	741,169	117,457,635	$	0.00100	$	117,458	$	858,627
50	Distribution Charge - three phase (kWh)	741,168,960	$	0.03684	$	27,304,664	117,457,635	$	0.03684	$	4,327,139	$	31,631,804
51	**Subtotal Energy Charges and Adjustment Charges**				**$**	**75,903,854**				**$**	**12,028,954**	**$**	**87,932,808**
52													
53	**TOTAL Revenue**				**$**	**82,813,204**				**$**	**13,232,804**	**$**	**96,046,008**
54													
55	**Summary of Revenue**												
56	Customer Charge				$	6,909,350				$	1,203,850	$	8,113,200
57	Demand Charge					-					-		-
58	Energy Charge					75,903,854					12,028,954		87,932,808
59	**Total Revenue**				**$**	**82,813,204**				**$**	**13,232,804**	**$**	**96,046,008**
60	*Check*												

EXHIBIT 2
Rate Benchmarking Analysis - CPS

Austin Energy
Rate Benchmarking Analysis
Exhibit 2 - CPS

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Proof of Revenue						
		Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL)			**Austin Energy Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
1								
2	**Austin Energy Rate Schedule**							
3								
4	**Customer Charge (months)**	**138,187**	**$ 25.00**	**$ 3,454,675**	**24,077**	**$ 25.00**	**$ 601,925**	**$ 4,056,600**
5								
6	Demand Charges							
7	Winter ($/kW-billed)	1,877,111	$ 5.15	9,667,124	339,867	$ 5.12	1,740,119	11,407,243
8	Summer ($/kW-billed)	1,012,365	$ 6.15	6,226,042	164,792	$ 6.11	1,006,881	7,232,923
9	Subtotal Demand Charges		$ 5.48	$ 15,893,166		$ 5.45	$ 2,747,000	$ 18,640,166
10								
11	Electric Delivery ($/kW-billed)	2,889,476	$ 4.00	11,557,904	504,659	$ 3.98	2,008,544	13,566,448
12	Regulatory Charge ($/kW)	2,889,476	$ 2.56	7,397,059	504,659	$ 2.56	1,291,928	8,688,986
13	Temporary Supplemental Charge (OCL)	2,889,476	$ -	-	504,659	$ 0.13	65,606	65,606
14	**Subtotal Demand Charges and Adjustment Charges**		**$ 6.56**	**$ 34,848,129**		**$ 12.12**	**$ 6,113,077**	**$ 40,961,206**
15								
16	Energy Charge (kWh)							
17	Winter Energy (kWh)	433,209,672	$ 0.02414	10,457,681	70,674,283	$ 0.02399	1,695,476	12,153,158
18	Summer Energy (kWh)	307,959,288	$ 0.02914	8,973,934	46,783,352	$ 0.02896	1,354,846	10,328,780
19	Subtotal Energy Charge		$ 0.02581	$ 19,431,615		$ 0.02565	$ 3,050,322	$ 22,481,937
20								
21	FAC or PSA (kWh)	741,168,960	$ 0.03709	27,489,957	117,457,635	$ 0.03709	4,356,504	31,846,460
22	Customer Assistance Program ($/kWh)	741,168,960	$ 0.00065	481,760	117,457,635	$ 0.00065	76,347	558,107
23	Service Area Street Lighting ($/kWh)	741,168,960	$ 0.00076	563,288	117,457,635	$ -	-	563,288
24	Energy Efficiency Services ($/kWh)	741,168,960	$ 0.00522	3,868,902	117,457,635	$ 0.00522	613,129	4,482,031
25	Transmission Service Adjustment	741,168,960	$ -	-	117,457,635	$ -	-	-
26	**Subtotal Energy Charge and Adjustment Charges**		**$ 0.06953**	**$ 51,835,522**		**$ 0.06861**	**$ 8,096,302**	**$ 59,931,824**
27								
28	**TOTAL Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
29	*Check*							
30	**Summary of Revenue**							
31	Customer Charge			$ 3,454,675			$ 601,925	$ 4,056,600
32	Demand Charge			34,848,129			6,113,077	40,961,206
33	Energy Charge			51,835,522			8,096,302	59,931,824
34	**Total Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
35	*Check*							
36								
37								

Austin Energy
Rate Benchmarking Analysis
Exhibit 2 - CPS

(A)	(B)	(J)		(K)		(L)	(M)		(N)		(O)		(P)
		CPS Energy Structure w Austin Energy Revenue Requirement											
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)					**Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)**						**Total CPS Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**		**Rate**		**Revenues**	**Billing Units**		**Rate**		**Revenues**		**Total Revenues**
38	**CPS Rate Schedule**												
39													
40	**Customer Charge (months)**	**138,187**	**$**	**14.07**	**$**	**1,943,634**	**24,077**	**$**	**14.07**	**$**	**338,649**	**$**	**2,282,283**
41													
42	**Demand Charge (kW)**	**3,394,135**	**$**	**-**	**$**	**-**	**19,144,825**	**$**	**-**	**$**	**-**	**$**	**-**
43													
44													
45	Energy Charge (kWh)												
46	Energy Charge (First 1,600 kWh)	544,974,711	$	0.11558	$	62,986,064	90,329,812	$	0.11558	$	10,439,969	$	73,426,033
47	Energy Charge (additional kWh)	196,194,249	$	0.05337	$	10,470,408	27,127,823	$	0.05337	$	1,447,746	$	11,918,153
48	Subtotal Energy Charges				$	73,456,472				$	11,887,715	$	85,344,187
49													
50	Peak Capacity Charge - June- Sept (kwh> 600kWh)	279,399,696	$	0.03183	$	8,892,633	41,833,412	$	0.03183	$	1,331,459	$	10,224,091
51	Peak Capacity Charge - Oct - May (kWh>600kWh)	380,244,702	$	0.01607	$	6,112,268	61,388,971	$	0.01607	$	986,801	$	7,099,069
52	Subtotal Peak Capacity Charge		$	0.02133	$	15,004,901		$	0.02133	$	2,318,260	$	17,323,161
53													
54													
55	**Subtotal Energy Charges and Peak Capacity Charge**				**$**	**88,461,372**				**$**	**14,205,975**	**$**	**102,667,347**
56													
57	**TOTAL Revenue**				**$**	**90,405,006**				**$**	**14,544,624**	**$**	**104,949,630**
58													
59	**Summary of Revenue**												
60	Customer Charge				$	1,943,634				$	338,649	$	2,282,283
61	Demand Charge					-					-		-
62	Energy Charge					88,461,372					14,205,975		102,667,347
63	**Total Revenue**				**$**	**90,405,006**				**$**	**14,544,624**	**$**	**104,949,630**
64	*Check*												
65													

Austin Energy
Rate Benchmarking Analysis
Exhibit 2 - CPS

(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)
		CPS Energy Structure w CPS Revenue Requirement						
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)			Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)			Total CPS Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)
Line No.	Item	Billing Units	Rate	Revenues	Billing Units	Rate	Revenues	Total Revenues
38	**CPS Rate Schedule**							
39								
40	**Customer Charge (months)**	**138,187**	**$ 8.75**	**$ 1,209,136**	**24,077**	**$ 8.75**	**$ 210,674**	**$ 1,419,810**
41								
42	**Demand Charge (kW)**	**3,394,135**	**$ -**	**$ -**	**19,144,825**	**$ -**	**$ -**	**$ -**
43								
44								
45	Energy Charge (kWh)							
46	Energy Charge (First 1,600 kWh)	544,974,711	$ 0.07190	$ 39,183,682	90,329,812	$ 0.07190	$ 6,494,713	$ 45,678,395
47	Energy Charge (additional kWh)	196,194,249	$ 0.03320	$ 6,513,649	27,127,823	$ 0.03320	$ 900,644	$ 7,414,293
48	Subtotal Energy Charges			$ 45,697,331			$ 7,395,357	$ 53,092,688
49								
50	Peak Capacity Charge - June- Sept (kwh> 600kWh)	279,399,696	$ 0.01980	$ 5,532,114	41,833,412	$ 0.01980	$ 828,302	$ 6,360,416
51	Peak Capacity Charge - Oct - May (kWh>600kWh)	380,244,702	$ 0.01000	$ 3,802,447	61,388,971	$ 0.01000	$ 613,890	$ 4,416,337
52	Subtotal Peak Capacity Charge		$ 0.01327	$ 9,334,561		$ 0.01327	$ 1,442,191	$ 10,776,752
53								
54								
55	**Subtotal Energy Charges and Peak Capacity Charge**			**$ 55,031,892**			**$ 8,837,548**	**$ 63,869,440**
56								
57	**TOTAL Revenue**			**$ 56,241,028**			**$ 9,048,222**	**$ 65,289,250**
58								
59	**Summary of Revenue**							
60	Customer Charge			$ 1,209,136			$ 210,674	$ 1,419,810
61	Demand Charge			-			-	-
62	Energy Charge			55,031,892			8,837,548	63,869,440
63	**Total Revenue**			**$ 56,241,028**			**$ 9,048,222**	**$ 65,289,250**
64	*Check*							
65								

EXHIBIT 3
Rate Benchmarking Analysis - FCU

Austin Energy
Rate Benchmarking Analysis
Exhibit 3 - FCU

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Proof of Revenue						
		Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL)			**Austin Energy Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
1								
2	**Austin Energy Rate Schedule**							
3								
4	**Customer Charge (months)**	**138,187**	**$ 25.00**	**$ 3,454,675**	**24,077**	**$ 25.00**	**$ 601,925**	**$ 4,056,600**
5								
6	Demand Charges							
7	Winter ($/kW-billed)	1,877,111	$ 5.15	9,667,124	339,867	$ 5.12	1,740,119	11,407,243
8	Summer ($/kW-billed)	1,012,365	$ 6.15	6,226,042	164,792	$ 6.11	1,006,881	7,232,923
9	Subtotal Demand Charges		$ 5.48	$ 15,893,166		$ 5.45	$ 2,747,000	$ 18,640,166
10								
11	Electric Delivery ($/kW-billed)	2,889,476	$ 4.00	11,557,904	504,659	$ 3.98	2,008,544	13,566,448
12	Regulatory Charge ($/kW)	2,889,476	$ 2.56	7,397,059	504,659	$ 2.56	1,291,928	8,688,986
13	Temporary Supplemental Charge (OCL)	2,889,476	$ -	-	504,659	$ 0.13	65,606	65,606
14	**Subtotal Demand Charges and Adjustment Charges**		**$ 6.56**	**$ 34,848,129**		**$ 12.12**	**$ 6,113,077**	**$ 40,961,206**
15								
16	Energy Charge (kWh)							
17	Winter Energy (kWh)	433,209,672	$ 0.02414	10,457,681	70,674,283	$ 0.02399	1,695,476	12,153,158
18	Summer Energy (kWh)	307,959,288	$ 0.02914	8,973,934	46,783,352	$ 0.02896	1,354,846	10,328,780
19	Subtotal Energy Charge		$ 0.02581	$ 19,431,615		$ 0.02565	$ 3,050,322	$ 22,481,937
20								
21	FAC or PSA (kWh)	741,168,960	$ 0.03709	27,489,957	117,457,635	$ 0.03709	4,356,504	31,846,460
22	Customer Assistance Program ($/kWh)	741,168,960	$ 0.00065	481,760	117,457,635	$ 0.00065	76,347	558,107
23	Service Area Street Lighting ($/kWh)	741,168,960	$ 0.00076	563,288	117,457,635	$ -	-	563,288
24	Energy Efficiency Services ($/kWh)	741,168,960	$ 0.00522	3,868,902	117,457,635	$ 0.00522	613,129	4,482,031
25	Transmission Service Adjustment	741,168,960	$ -	-	117,457,635	$ -	-	-
26	**Subtotal Energy Charge and Adjustment Charges**		**$ 0.06953**	**$ 51,835,522**		**$ 0.06861**	**$ 8,096,302**	**$ 59,931,824**
27								
28	**TOTAL Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
29	*Check*							
30	**Summary of Revenue**							
31	Customer Charge			$ 3,454,675			$ 601,925	$ 4,056,600
32	Demand Charge			34,848,129			6,113,077	40,961,206
33	Energy Charge			51,835,522			8,096,302	59,931,824
34	**Total Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
35	*Check*							
36								
37								

Austin Energy
Rate Benchmarking Analysis
Exhibit 3 - FCU

(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
		FCU w AE Revenue Requirement						
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)			**Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Fort Collins Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
38	**FCU Rate Schedule**							
39	***General Service (<25kW)***							
40	Customer Charge							
41	Fixed Charge - three phase above 200 amp (months)	97,763	$ 16.63	$ 1,625,469	17,198	$ 16.63	$ 285,945	$ 1,911,414
42	**Customer Charge**		**$ 16.63**	**$ 1,625,469**		**$ 16.63**	**$ 285,945**	**$ 1,911,414**
43								
44	Demand Charge (kWh)							
45	Summer (June, July, Aug)	103,302,438	$ 0.03923	$ 4,052,532	17,310,188	$ 0.03923	$ 679,075	$ 4,731,606
46	Non-Summer (Jan - May, Sept - Dec)	240,187,668	$ 0.02110	$ 5,068,425	39,156,284	$ 0.02147	$ 840,497	$ 5,908,922
47	**Subtotal Demand Charges**	**343,490,106**	**$ 0.0256**	**$ 9,120,957**	**56,466,472**	**$ 0.0259**	**$ 1,519,572**	**$ 10,640,528**
48								
49								
50	Energy Charge (kWh)							
51	Summer (June, July, Aug)	103,302,438	$ 0.05892	$ 6,086,112	17,310,188	$ 0.05892	$ 1,019,838	$ 7,105,950
52	Non-Summer (Jan - May, Sept - Dec)	240,187,668	$ 0.05665	$ 13,606,510	39,156,284	$ 0.05665	$ 2,218,184	$ 15,824,694
53	Subtotal Energy Charge	343,490,106	$ 0.0572	$ 19,692,623	56,466,472	$ 0.0572	$ 3,238,022	$ 22,930,645
54								
55	Distribution Facilities Charge	343,490,106	$ 0.03215	$ 11,042,722	56,466,472	$ 0.03215	$ 1,815,317	$ 12,858,040
56	**Subtotal Energy Charges and Adjustment Charge**		**$ 0.0894**	**$ 30,735,345**		**$ 0.0894**	**$ 5,053,339**	**$ 35,788,684**
57								
58	Taxes and Franchise		6.0%	$ 2,488,906		6.0%	$ 411,531	$ 2,900,438
59								
60	**Subtotal <25kW Customer Revenue**	**-**		**$ 43,970,677**			**$ 7,270,387**	**$ 51,241,064**
61								
62	**General Services GS25 (>25kW <50kW)**							
63	Customer Charge							
64	Fixed Charge - three phase above 200 amp (months)	40,017	$ 16.63	$ 665,348	6,843	$ 16.63	$ 113,776	$ 779,124
65	**Customer Charge**		**$ 16.63**	**$ 665,348**		**$ 16.63**	**$ 113,776**	**$ 779,124**
66								
67	Demand Charge (kW)							
68	Summer (June, July, Aug)	372,888	$ 10.65	$ 3,971,301	54,811	$ 10.65	$ 583,745	$ 4,555,046
69	Non-Summer (Jan - May, Sept - Dec)	1,043,283	$ 6.19	$ 6,456,833	191,927	$ 6.19	$ 1,187,828	$ 7,644,661
70	**Subtotal Demand Charges**	**1,416,171**	**$ 7.3042**	**$ 10,428,134**	**246,738**	**$ 7.3042**	**$ 1,771,572**	**$ 12,199,707**
71								
72								
73	Energy Charge (kWh)							
74	Summer (June, July, Aug)	124,334,915	$ 0.05892	$ 7,325,251	17,144,952	$ 0.05892	$ 1,010,103	$ 8,335,354
75	Non-Summer (Jan - May, Sept - Dec)	272,861,401	$ 0.05665	$ 15,457,461	43,751,423	$ 0.05665	$ 2,478,496	$ 17,935,957
76	Subtotal Energy Charges	397,196,316	$ 0.0572	$ 22,782,712	60,896,375	$ 0.0572	$ 3,488,599	$ 26,271,311
77								
78	Distribution Facilities Charge	397,196,316	$ 0.02493	$ 9,900,427	60,896,375	$ 0.02493	$ 1,517,890	$ 11,418,317
79	**Subtotal Energy Charges and Adjustment Charge**		**$ 0.0821**	**$ 32,683,139**		**$ 0.0821**	**$ 5,006,489**	**$ 37,689,628**
80								
81	Taxes and Franchise		6.0%	$ 2,626,597		6.0%	$ 413,510	$ 3,040,108
82								
83	**Subtotal 25kW<50kW Customer Revenue**			**$ 46,403,219**			**$ 7,305,347**	**$ 53,708,566**
84								
85								
86	**TOTAL Revenue**			**$ 90,373,896**			**$ 14,575,734**	**$ 104,949,630**
87								
88	**Summary of Revenue**							
89	Customer Charge			$ 2,290,817			$ 399,721	$ 2,690,537
90	Demand Charge			19,549,091			3,291,144	22,840,235
91	Energy Charge			63,418,484			10,059,828	73,478,312
92	Taxes and Franchise			5,115,504			825,042	5,940,545
93	**Total Revenue**			**$ 90,373,896**			**$ 14,575,734**	**$ 104,949,630**
94	*Check*							

Austin Energy
Rate Benchmarking Analysis
Exhibit 3 - FCU

(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)
		FCU w FCU Revenue Requirement						
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)			**Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Fort Collins Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
38	**FCU Rate Schedule**							
39	***General Service (<25kW)***							
40	Customer Charge							
41	Fixed Charge - three phase above 200 amp (months)	97,763	$ 11.74	$ 1,147,738	17,198	$ 11.74	$ 201,905	$ 1,349,642
42	**Customer Charge**		**$ 11.74**	**$ 1,147,738**		**$ 11.74**	**$ 201,905**	**$ 1,349,642**
43								
44	Demand Charge (kWh)							
45	Summer (June, July, Aug)	103,302,438	$ 0.02770	$ 2,861,478	17,310,188	$ 0.02770	$ 479,492	$ 3,340,970
46	Non-Summer (Jan - May, Sept - Dec)	240,187,668	$ 0.01490	$ 3,578,796	39,156,284	$ 0.01490	$ 583,429	$ 4,162,225
47	**Subtotal Demand Charges**	**343,490,106**	**$ 0.0181**	**$ 6,440,274**	**56,466,472**	**$ 0.0181**	**$ 1,062,921**	**$ 7,503,195**
48								
49								
50	Energy Charge (kWh)							
51	Summer (June, July, Aug)	103,302,438	$ 0.04160	$ 4,297,381	17,310,188	$ 0.04160	$ 720,104	$ 5,017,485
52	Non-Summer (Jan - May, Sept - Dec)	240,187,668	$ 0.04000	$ 9,607,507	39,156,284	$ 0.04000	$ 1,566,251	$ 11,173,758
53	Subtotal Energy Charge	343,490,106	$ 0.0404	$ 13,904,888	56,466,472	$ 0.0404	$ 2,286,355	$ 16,191,243
54								
55	Distribution Facilities Charge	343,490,106	$ 0.02270	$ 7,797,225	56,466,472	$ 0.02270	$ 1,281,789	$ 9,079,014
56	**Subtotal Energy Charges and Adjustment Charge**		**$ 0.0631**	**$ 21,702,114**		**$ 0.0631**	**$ 3,568,144**	**$ 25,270,258**
57								
58	Taxes and Franchise		6.0%	$ 1,757,407		6.0%	$ 289,978	$ 2,047,386
59								
60	**Subtotal <25kW Customer Revenue**	-		**$ 31,047,532**			**$ 5,122,948**	**$ 36,170,480**
61								
62	**General Services GS25 (>25kW <50kW)**							
63	Customer Charge							
64	Fixed Charge - three phase above 200 amp (months)	40,017	$ 11.74	$ 469,800	6,843	$ 11.74	$ 80,337	$ 550,136
65	**Customer Charge**		**$ 11.74**	**$ 469,800**		**$ 11.74**	**$ 80,337**	**$ 550,136**
66								
67	Demand Charge (kW)							
68	Summer (June, July, Aug)	372,888	$ 7.52	$ 2,804,121	54,811	$ 7.52	$ 412,180	$ 3,216,301
69	Non-Summer (Jan - May, Sept - Dec)	1,043,283	$ 4.37	$ 4,559,146	191,927	$ 4.37	$ 838,721	$ 5,397,867
70	**Subtotal Demand Charges**	**1,416,171**	$ 5.16	**$ 7,363,267**	**246,738**	$ 5.16	**$ 1,250,901**	**$ 8,614,168**
71								
72								
73	Energy Charge (kWh)							
74	Summer (June, July, Aug)	124,334,915	$ 0.0416	$ 5,172,332	17,144,952	$ 0.0416	$ 713,230	$ 5,885,562
75	Non-Summer (Jan - May, Sept - Dec)	272,861,401	$ 0.0400	$ 10,914,456	43,751,423	$ 0.0400	$ 1,750,057	$ 12,664,513
76	Subtotal Energy Charges	397,196,316	$ 0.0404	$ 16,086,788	60,896,375	$ 0.0404	$ 2,463,287	$ 18,550,075
77								
78	Distribution Facilities Charge	397,196,316	$ 0.0176	$ 6,990,655	60,896,375	$ 0.0176	$ 1,071,776	$ 8,062,431
79	**Subtotal Energy Charges and Adjustment Charge**		**$ 0.0580**	**$ 23,077,444**		**$ 0.0580**	**$ 3,535,063**	**$ 26,612,507**
80								
81	Taxes and Franchise		6.0%	$ 1,854,631		6.0%	$ 291,978	$ 2,146,609
82								
83	**Subtotal 25kW<50kW Customer Revenue**			**$ 32,765,141**			**$ 5,158,279**	**$ 37,923,420**
84								
85								
86	**TOTAL Revenue**			**$ 63,812,673**			**$ 10,281,226**	**$ 74,093,900**
87								
88	**Summary of Revenue**							
89	Customer Charge			$ 1,617,537			$ 282,241	$ 1,899,779
90	Demand Charge			13,803,541			2,313,822	16,117,362
91	Energy Charge			44,779,557			7,103,207	51,882,764
92	Taxes and Franchise			3,612,038			581,956	4,193,994
93	**Total Revenue**			**$ 63,812,673**			**$ 10,281,226**	**$ 74,093,900**
94	*Check*							

EXHIBIT 4
Rate Benchmarking Analysis - LADWP

Austin Energy
Rate Benchmarking Analysis
Exhibit 4 - LADWP

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Proof of Revenue						
		Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL)			**Austin Energy Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
1								
2	**Austin Energy Rate Schedule**							
3								
4	**Customer Charge (months)**	**138,187**	**$ 25.00**	**$ 3,454,675**	**24,077**	**$ 25.00**	**$ 601,925**	**$ 4,056,600**
5								
6	Demand Charges							
7	Winter ($/kW-billed)	1,877,111	$ 5.15	9,667,124	339,867	$ 5.12	1,740,119	11,407,243
8	Summer ($/kW-billed)	1,012,365	$ 6.15	6,226,042	164,792	$ 6.11	1,006,881	7,232,923
9	Subtotal Demand Charges		$ 5.48	$ 15,893,166		$ 5.45	$ 2,747,000	$ 18,640,166
10								
11	Electric Delivery ($/kW-billed)	2,889,476	$ 4.00	11,557,904	504,659	$ 3.98	2,008,544	13,566,448
12	Regulatory Charge ($/kW)	2,889,476	$ 2.56	7,397,059	504,659	$ 2.56	1,291,928	8,688,986
13	Temporary Supplemental Charge (OCL)	2,889,476	$ -	-	504,659	$ 0.13	65,606	65,606
14	**Subtotal Demand Charges and Adjustment Charges**		**$ 6.56**	**$ 34,848,129**		**$ 12.12**	**$ 6,113,077**	**$ 40,961,206**
15								
16	Energy Charge (kWh)							
17	Winter Energy (kWh)	433,209,672	$ 0.02414	10,457,681	70,674,283	$ 0.02399	1,695,476	12,153,158
18	Summer Energy (kWh)	307,959,288	$ 0.02914	8,973,934	46,783,352	$ 0.02896	1,354,846	10,328,780
19	Subtotal Energy Charge		$ 0.02581	$ 19,431,615		$ 0.02565	$ 3,050,322	$ 22,481,937
20								
21	FAC or PSA (kWh)	741,168,960	$ 0.03709	27,489,957	117,457,635	$ 0.03709	4,356,504	31,846,460
22	Customer Assistance Program ($/kWh)	741,168,960	$ 0.00065	481,760	117,457,635	$ 0.00065	76,347	558,107
23	Service Area Street Lighting ($/kWh)	741,168,960	$ 0.00076	563,288	117,457,635	$ -	-	563,288
24	Energy Efficiency Services ($/kWh)	741,168,960	$ 0.00522	3,868,902	117,457,635	$ 0.00522	613,129	4,482,031
25	Transmission Service Adjustment	741,168,960	$ -	-	117,457,635	$ -	-	-
26	**Subtotal Energy Charge and Adjustment Charges**		**$ 0.06953**	**$ 51,835,522**		**$ 0.06861**	**$ 8,096,302**	**$ 59,931,824**
27								
28	**TOTAL Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
29	*Check*							
30	**Summary of Revenue**							
31	Customer Charge			$ 3,454,675			$ 601,925	$ 4,056,600
32	Demand Charge			34,848,129			6,113,077	40,961,206
33	Energy Charge			51,835,522			8,096,302	59,931,824
34	**Total Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
35	*Check*							
36								
37								

Austin Energy
Rate Benchmarking Analysis
Exhibit 4 - LADWP

(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
		LADWP Structure w AE Revenue Requirement						
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)			**Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Los Angeles Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
38	**LADWP Rate Schedule**							
39	***Small General Service (<30kW)***							
40	Customer Charge (months)							
41	Service Charge	111,757	$ 5.91	$ 660,861	19,484	$ 5.91	$ 115,216	$ 776,078
42	Customer Charge		**$ 5.91**	**$ 660,861**		**$ 5.91**	**$ 115,216**	**$ 776,078**
43								
44	Demand Charge (kW)							
45	Facilities Charge	1,851,685	$ 4.55	$ 8,422,856	320,072	$ 4.55	$ 1,455,929	$ 9,878,785
46	Demand Charges	1,851,685	$ 4.55	$ 8,422,856	320,072	$ 4.55	$ 1,455,929	$ 9,878,785
47								
48	Electric Subsidy Adjustment (ESA)	1,851,685	$ 0.42	$ 774,903	320,072	$ 0.42	$ 133,945	$ 908,848
49	Reliability Cost Adjustment (RCA)	1,851,685	$ 0.87	$ 1,617,188	320,072	$ 0.87	$ 279,538	$ 1,896,727
50	**Subtotal Demand Charges and Adjustment Charges**		**$ 5.84**	**$ 10,814,948**		**$ 5.84**	**$ 1,869,413**	**$ 12,684,360**
51								
52	Energy Charge (kWh)							
53	High Season (June - Sept)	134,563,188	$ 0.05966	$ 8,028,234	21,668,700	$ 0.05966	$ 1,292,786	$ 9,321,019
54	Low Season (Oct - May)	311,525,749	$ 0.03883	$ 12,095,969	49,912,000	$ 0.03883	$ 1,937,991	$ 14,033,960
55	Subtotal Energy Charges	446,088,938	$ 0.0440	$ 20,124,203	71,580,701	$ 0.0440	$ 3,230,777	$ 23,354,979
56								
57	Energy Cost Adjustment (ECA)	446,088,938	$ 0.05176	$ 23,091,707	71,580,701	$ 0.05176	$ 3,705,361	$ 26,797,068
58	**Subtotal Energy Charges and Adjustment Charge**		**$ 0.0958**	**$ 43,215,910**		**$ 0.0958**	**$ 6,936,138**	**$ 50,152,047**
59								
60	**Subtotal <30kW Customer Revenue**			**$ 54,691,719**			**$ 8,920,766**	**$ 63,612,485**
61								
62	***Primary Service (>30kW)***							
63	Customer Charge (months)							
64	Service Charge	**26,228**	**$ 5.91**	**$ 155,096**	**4,579**	**$ 5.91**	**$ 27,077**	**$ 182,173**
65	Customer Charge							
66								
67	Demand Charge (kW)							
68	High Season (June - Sept)	276,860	$ 8.19	$ 2,266,859	40,377	$ 8.19	$ 330,595	$ 2,597,453
69	Low Season (Oct - May)	760,932	$ 5.00	$ 3,807,418	144,210	$ 5.00	$ 721,575	$ 4,528,994
70	Subtotal Demand Charges		$ 6.07	$ 6,074,277		$ 6.07	$ 1,052,170	$ 7,126,447
71								
72	Facilities Charge	1,037,791	$ 4.55	$ 4,720,655	184,587	$ 4.55	$ 839,641	$ 5,560,297
73	Electric Subsidy Adjustment (ESA)	1,037,791	$ 0.41849	$ 434,300	184,587	$ 0.41849	$ 77,247	$ 511,547
74	Reliability Cost Adjustment (RCA)	1,037,791	$ 0.87336	$ 906,366	184,587	$ 0.87336	$ 161,211	$ 1,067,577
75	**Subtotal Demand Charges and Adjustment Charges**		**$ 11.9056**	**$ 12,135,598**		**$ 11.9056**	**$ 2,130,270**	**$ 14,265,868**
76								
77	Energy Charge (kWh)							
78	High Season (June - Sept)	93,261,546	$ 0.03316	$ 3,092,591	12,825,386	$ 0.03316	$ 425,295	$ 3,517,886
79	Low Season (Oct - May)	194,188,360	$ 0.02725	$ 5,291,056	32,102,403	$ 0.02725	$ 874,695	$ 6,165,751
80	**Subtotal Energy Charges**		$ 0.0292	$ 8,383,647		$ 0.0292	$ 1,299,990	$ 9,683,637
81								
82	Energy Cost Adjustment (ECA)	287,449,905	$ 0.05176	$ 14,879,788	44,927,788	$ 0.05176	$ 2,325,678	$ 17,205,467
83	**Subtotal Energy Charges and Adjustment Charge**		**$ 0.0810**	**$ 23,263,435**		**$ 0.0810**	**$ 3,625,668**	**$ 26,889,103**
84								
85	**Subtotal >30kW Customer Revenue**			**$ 35,554,129**			**$ 5,783,016**	**$ 41,337,145**
86								
87	**TOTAL Revenue**			**$ 90,245,848**			**$ 14,703,782**	**$ 104,949,630**
88								
89	**Summary of Revenue**							
90	Customer Charge			$ 815,958			$ 142,294	$ 958,251
91	Demand Charge			22,950,546			3,999,683	26,950,228
92	Energy Charge			66,479,345			10,561,806	77,041,150
93	**Total Revenue**			**$ 90,245,848**			**$ 14,703,782**	**$ 104,949,630**
94	*Check*							

Austin Energy
Rate Benchmarking Analysis
Exhibit 4 - LADWP

(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)
		LADWP Structure w LADWP Revenue Requirement						
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)			**Commecial Secondary Voltage ≥ 10 < 50 kW OCL)**			**Total Los Angeles Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
38	**LADWP Rate Schedule**							
39	***Small General Service (<30kW)***							
40	Customer Charge (months)							
41	Service Charge	111,757	$ 6.50	$ 726,421	19,484	$ 6.50	$ 126,646	$ 853,067
42	Customer Charge		**$ 6.50**	**$ 726,421**		**$ 37.50**	**$ 126,646**	**$ 853,067**
43								
44	Demand Charge (kW)							
45	Facilities Charge	1,851,685	$ 5.00	$ 9,258,424	320,072	$ 5.00	$ 1,600,360	$ 10,858,785
46	Demand Charges	1,851,685	$ 5.00	$ 9,258,424	320,072	$ 5.00	$ 1,600,360	$ 10,858,785
47								
48	Electric Subsidy Adjustment (ESA)	1,851,685	$ 0.46	$ 851,775	320,072	$ 0.46	$ 147,233	$ 999,008
49	Reliability Cost Adjustment (RCA)	1,851,685	$ 0.96	$ 1,777,617	320,072	$ 0.96	$ 307,269	$ 2,084,887
50	**Subtotal Demand Charges and Adjustment Charges**			**$ 11,887,817**			**$ 2,054,863**	**$ 13,942,680**
51								
52	Energy Charge (kWh)							
53	High Season (June - Sept)	134,563,188	$ 0.06558	$ 8,824,654	21,668,700	$ 0.06558	$ 1,421,033	$ 10,245,687
54	Low Season (Oct - May)	311,525,749	$ 0.04268	$ 13,295,919	49,912,000	$ 0.04268	$ 2,130,244	$ 15,426,163
55	Subtotal Energy Charges	446,088,938	$ 0.0484	$ 22,120,573	71,580,701	$ 0.0484	$ 3,551,278	$ 25,671,850
56								
57	Energy Cost Adjustment (ECA)	446,088,938	$ 0.05690	$ 25,382,461	71,580,701	$ 0.05690	$ 4,072,942	$ 29,455,402
58	**Subtotal Energy Charges and Adjustment Charge**		**$ 0.1053**	**$ 47,503,033**		**$ 0.1053**	**$ 7,624,219**	**$ 55,127,253**
59								
60	**Subtotal <30kW Customer Revenue**			**$ 60,117,271**			**$ 9,805,728**	**$ 69,922,999**
61								
62	***Primary Service (>30kW)***							
63	Customer Charge (months)							
64	Service Charge	**26,228**	**$ 6.50**	**$ 170,482**	**4,579**	**$ 6.50**	**$ 29,764**	**$ 200,246**
65	Customer Charge							
66								
67	Demand Charge (kW)							
68	High Season (June - Sept)	276,860	$ 9.00	$ 2,491,737	40,377	$ 9.00	$ 363,391	$ 2,855,127
69	Low Season (Oct - May)	760,932	$ 5.50	$ 4,185,124	144,210	$ 5.50	$ 793,157	$ 4,978,281
70	Subtotal Demand Charges		$ 6.67	$ 6,676,860		$ 6.67	$ 1,156,548	$ 7,833,408
71								
72	Facilities Charge	1,037,791	$ 5.00	$ 5,188,956	184,587	$ 5.00	$ 922,936	$ 6,111,892
73	Electric Subsidy Adjustment (ESA)	1,037,791	$ 0.46000	$ 477,384	184,587	$ 0.46000	$ 84,910	$ 562,294
74	Reliability Cost Adjustment (RCA)	1,037,791	$ 0.96000	$ 996,280	184,587	$ 0.96000	$ 177,204	$ 1,173,483
75	**Subtotal Demand Charges and Adjustment Charges**		**$ 13.0867**	**$ 13,339,479**		**$ 13.0867**	**$ 2,341,598**	**$ 15,681,077**
76								
77	Energy Charge (kWh)							
78	High Season (June - Sept)	93,261,546	$ 0.03645	$ 3,399,383	12,825,386	$ 0.03645	$ 467,485	$ 3,866,869
79	Low Season (Oct - May)	194,188,360	$ 0.02995	$ 5,815,941	32,102,403	$ 0.02995	$ 961,467	$ 6,777,408
80	**Subtotal Energy Charges**		$ 0.0321	$ 9,215,325		$ 0.0321	$ 1,428,952	$ 10,644,277
81								
82	Energy Cost Adjustment (ECA)	287,449,905	$ 0.05690	$ 16,355,900	44,927,788	$ 0.05690	$ 2,556,391	$ 18,912,291
83	**Subtotal Energy Charges and Adjustment Charge**		**$ 0.0890**	**$ 25,571,224**		**$ 0.0890**	**$ 3,985,343**	**$ 29,556,568**
84								
85	**Subtotal >30kW Customer Revenue**			**$ 39,081,186**			**$ 6,356,705**	**$ 45,437,891**
86								
87	**TOTAL Revenue**			**$ 99,198,456**			**$ 16,162,433**	**$ 115,360,889**
88								
89	**Summary of Revenue**							
90	Customer Charge			$ 896,903			$ 156,410	$ 1,053,312
91	Demand Charge			25,227,296			4,396,461	29,623,757
92	Energy Charge			73,074,258			11,609,563	84,683,821
93	**Total Revenue**			**$ 99,198,456**			**$ 16,162,433**	**$ 115,360,889**
94	*Check*							

EXHIBIT 5
Rate Benchmarking Analysis - PEC

Austin Energy
Rate Benchmarking Analysis
Exhibit 5 - PEC

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Proof of Revenue						
		Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL)			**Austin Energy Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
1								
2	**Austin Energy Rate Schedule**							
3								
4	**Customer Charge (months)**	**138,187**	**$ 25.00**	**$ 3,454,675**	**24,077**	**$ 25.00**	**$ 601,925**	**$ 4,056,600**
5								
6	Demand Charges							
7	Winter ($/kW-billed)	1,877,111	$ 5.15	9,667,124	339,867	$ 5.12	1,740,119	11,407,243
8	Summer ($/kW-billed)	1,012,365	$ 6.15	6,226,042	164,792	$ 6.11	1,006,881	7,232,923
9	Subtotal Demand Charges		$ 5.48	$ 15,893,166		$ 5.45	$ 2,747,000	$ 18,640,166
10								
11	Electric Delivery ($/kW-billed)	2,889,476	$ 4.00	11,557,904	504,659	$ 3.98	2,008,544	13,566,448
12	Regulatory Charge ($/kW)	2,889,476	$ 2.56	7,397,059	504,659	$ 2.56	1,291,928	8,688,986
13	Temporary Supplemental Charge (OCL)	2,889,476	$ -	-	504,659	$ 0.13	65,606	65,606
14	**Subtotal Demand Charges and Adjustment Charges**		**$ 6.56**	**$ 34,848,129**		**$ 12.12**	**$ 6,113,077**	**$ 40,961,206**
15								
16	Energy Charge (kWh)							
17	Winter Energy (kWh)	433,209,672	$ 0.02414	10,457,681	70,674,283	$ 0.02399	1,695,476	12,153,158
18	Summer Energy (kWh)	307,959,288	$ 0.02914	8,973,934	46,783,352	$ 0.02896	1,354,846	10,328,780
19	Subtotal Energy Charge		$ 0.02581	$ 19,431,615		$ 0.02565	$ 3,050,322	$ 22,481,937
20								
21	FAC or PSA (kWh)	741,168,960	$ 0.03709	27,489,957	117,457,635	$ 0.03709	4,356,504	31,846,460
22	Customer Assistance Program ($/kWh)	741,168,960	$ 0.00065	481,760	117,457,635	$ 0.00065	76,347	558,107
23	Service Area Street Lighting ($/kWh)	741,168,960	$ 0.00076	563,288	117,457,635	$ -	-	563,288
24	Energy Efficiency Services ($/kWh)	741,168,960	$ 0.00522	3,868,902	117,457,635	$ 0.00522	613,129	4,482,031
25	Transmission Service Adjustment	741,168,960	$ -	-	117,457,635	$ -	-	-
26	**Subtotal Energy Charges and Adjustment Charges**		**$ 0.06953**	**$ 51,835,522**		**$ 0.06861**	**$ 8,096,302**	**$ 59,931,824**
27								
28	**TOTAL Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
29	*Check*							
30	**Summary of Revenue**							
31	Customer Charge			$ 3,454,675			$ 601,925	$ 4,056,600
32	Demand Charge			34,848,129			6,113,077	40,961,206
33	Energy Charge			51,835,522			8,096,302	59,931,824
34	**Total Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
35	*Check*							
36								
37								

Austin Energy
Rate Benchmarking Analysis
Exhibit 5 - PEC

(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
		PEC Structure w AE Revenue Requirement						
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)			**Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Perdernales Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
38	**PEC Rate Schedule**							
39								
40	**Customer Charge (month)**	**138,187**	**$ 45.30**	**$ 6,260,286**	**24,077**	**$ 45.30**	**$ 1,090,760**	**$ 7,351,046**
41								
42	**Demand Charge (kW)**	**2,889,476**	**$ -**	**$ -**	**504,659**	**$ -**	**$ -**	**$ -**
43								
44								
45	Energy Charge (kWh)							
46	Energy Charge (kWh)	741,168,960	$ 0.08708	$ 64,539,814	117,457,635	$ 0.08708	$ 10,228,024	$ 74,767,838
47	Subtotal Energy Charge			**$ 64,539,814**			**$ 10,228,024**	**$ 74,767,838**
48								
49	Power Cost Recovery Factor (PCRF)	741,168,960	$ 0.00121	$ 895,391	117,457,635	$ 0.00121	141,898	$ 1,037,290
50	Delivery Charge (kWh)	741,168,960	$ 0.02538	$ 18,812,174	117,457,635	$ 0.02538	2,981,282	$ 21,793,456
51	**Subtotal Energy Charge and Adjustment Charges**		**$ 0.11367**	**$ 84,247,380**		**$ 0.11367**	**$ 13,351,204**	**$ 97,598,584**
52								
53	**TOTAL Revenue**			**$ 90,507,666**			**$ 14,441,964**	**$ 104,949,630**
54								
55	**Summary of Revenue**							
56	Customer Charge			$ 6,260,286			$ 1,090,760	$ 7,351,046
57	Demand Charge			-			-	-
58	Energy Charge			84,247,380			13,351,204	97,598,584
59	**Total Revenue**			**$ 90,507,666**			**$ 14,441,964**	**$ 104,949,630**
60	*Check*							

Austin Energy
Rate Benchmarking Analysis
Exhibit 5 - PEC

(A)	(B)	(Q)		(R)		(S)	(T)		(U)		(V)		(W)
		PEC Structure w PEC Revenue Requirement											
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)					**Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)**						**Total Perdernales Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**		**Rate**		**Revenues**	**Billing Units**		**Rate**		**Revenues**		**Total Revenues**
38	**PEC Rate Schedule**												
39													
40	**Customer Charge (month)**	**138,187**	**$**	**37.50**	**$**	**5,182,013**	**24,077**	**$**	**37.50**	**$**	**902,888**	**$**	**6,084,900**
41													
42	**Demand Charge (kW)**	**2,889,476**	**$**	**-**	**$**	**-**	**504,659**	**$**	**-**	**$**	**-**	**$**	**-**
43													
44													
45	Energy Charge (kWh)												
46	Energy Charge (kWh)	741,168,960	$	0.07208	$	53,423,459	117,457,635	$	0.07208	$	8,466,346	$	61,889,805
47	Subtotal Energy Charge				**$**	**53,423,459**				**$**	**8,466,346**	**$**	**61,889,805**
48													
49	Power Cost Recovery Factor (PCRF)	741,168,960	$	0.00100	$	741,169	117,457,635	$	0.00100	$	117,458	$	858,627
50	Delivery Charge (kWh)	741,168,960	$	0.02101	$	15,571,960	117,457,635	$	0.02101	$	2,467,785	$	18,039,745
51	**Subtotal Energy Charge and Adjustment Charges**		**$**	**0.09409**	**$**	**69,736,587**		**$**	**0.09**	**$**	**11,051,589**	**$**	**80,788,176**
52													
53	**TOTAL Revenue**				**$**	**74,918,600**				**$**	**11,954,476**	**$**	**86,873,076**
54													
55	**Summary of Revenue**												
56	Customer Charge				$	5,182,013				$	902,888	$	6,084,900
57	Demand Charge					-					-		-
58	Energy Charge					69,736,587					11,051,589		80,788,176
59	**Total Revenue**				**$**	**74,918,600**				**$**	**11,954,476**	**$**	**86,873,076**
60	*Check*												

EXHIBIT 6
Rate Benchmarking Analysis - Reliant

Austin Energy
Rate Benchmarking Analysis
Exhibit 6 - Reliant-CenterPoint

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Proof of Revenue						
		Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL)			**Austin Energy Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
1								
2	**Austin Energy Rate Schedule**							
3								
4	**Customer Charge (months)**	**138,187**	**$ 25.00**	**$ 3,454,675**	**24,077**	**$ 25.00**	**$ 601,925**	**$ 4,056,600**
5								
6	Demand Charges							
7	Winter ($/kW-billed)	1,877,111	$ 5.15	9,667,124	339,867	$ 5.12	1,740,119	11,407,243
8	Summer ($/kW-billed)	1,012,365	$ 6.15	6,226,042	164,792	$ 6.11	1,006,881	7,232,923
9	Subtotal Demand Charges		$ 5.48	$ 15,893,166		$ 5.45	$ 2,747,000	$ 18,640,166
10								
11	Electric Delivery ($/kW-billed)	2,889,476	$ 4.00	11,557,904	504,659	$ 3.98	2,008,544	13,566,448
12	Regulatory Charge ($/kW)	2,889,476	$ 2.56	7,397,059	504,659	$ 2.56	1,291,928	8,688,986
13	Temporary Supplemental Charge (OCL)	2,889,476	$ -	-	504,659	$ 0.13	65,606	65,606
14	**Subtotal Demand Charges and Adjustment Charges**		**$ 6.56**	**$ 34,848,129**		**$ 12.12**	**$ 6,113,077**	**$ 40,961,206**
15								
16	Energy Charge (kWh)							
17	Winter Energy (kWh)	433,209,672	$ 0.02414	10,457,681	70,674,283	$ 0.02399	1,695,476	12,153,158
18	Summer Energy (kWh)	307,959,288	$ 0.02914	8,973,934	46,783,352	$ 0.02896	1,354,846	10,328,780
19	Subtotal Energy Charge		$ 0.02581	$ 19,431,615		$ 0.02565	$ 3,050,322	$ 22,481,937
20								
21	FAC or PSA (kWh)	741,168,960	$ 0.03709	27,489,957	117,457,635	$ 0.03709	4,356,504	31,846,460
22	Customer Assistance Program ($/kWh)	741,168,960	$ 0.00065	481,760	117,457,635	$ 0.00065	76,347	558,107
23	Service Area Street Lighting ($/kWh)	741,168,960	$ 0.00076	563,288	117,457,635	$ -	-	563,288
24	Energy Efficiency Services ($/kWh)	741,168,960	$ 0.00522	3,868,902	117,457,635	$ 0.00522	613,129	4,482,031
25	Transmission Service Adjustment	741,168,960	$ -	-	117,457,635	$ -	-	-
26	**Subtotal Energy Charges and Adjustment Charges**		**$ 0.06953**	**$ 51,835,522**		**$ 0.06861**	**$ 8,096,302**	**$ 59,931,824**
27								
28	**TOTAL Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
29	*Check*							
30	**Summary of Revenue**							
31	Customer Charge			$ 3,454,675			$ 601,925	$ 4,056,600
32	Demand Charge			34,848,129			6,113,077	40,961,206
33	Energy Charge			51,835,522			8,096,302	59,931,824
34	**Total Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
35	*Check*							
36								
37								

Austin Energy
Rate Benchmarking Analysis
Exhibit 6 - Reliant-CenterPoint

(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
		Reliant/ CenterPoint Structure w AE Revenue Requirement						
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)			Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)			Total Reliant/CenterPoint Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)
Line No.	Item	Billing Units	Rate	Revenues	Billing Units	Rate	Revenues	Total Revenues
38	**Reliant/CenterPoint Rate Schedule**							
39								
40	Base Charge							
41	Reliant Usage Charge (months)	138,187	$ 10.27	$ 1,418,577	24,077	$ 10.27	$ 247,166	$ 1,665,743
42	CenterPoint Delivery Charge (months)	138,187	$ 8.79	$ 1,214,701	24,077	$ 8.79	$ 211,643	$ 1,426,345
43	**Base Charge**		**$ 19.06**	**$ 2,633,279**		**$ 19.06**	**$ 458,809**	**$ 3,092,088**
44								
45	**Demand Charge (kW)**	**2,889,476**	**$ -**	**$ -**	**504,659**	**$ -**	**$ -**	**$ -**
46								
47								
48	Energy Charge (kWh)							
49	Reliant Energy Charge (kWh)	741,168,960	$ 0.07635	$ 56,586,355	117,457,635	$ 0.07635	$ 8,967,590	$ 65,553,945
50	CenterPoint Energy Charge (kWh)	741,168,960	$ 0.04228	$ 31,337,370	117,457,635	$ 0.04228	$ 4,966,227	$ 36,303,597
51	**Subtotal Energy Charge**		**$ 0.11863**	**$ 87,923,725**		**$ 0.11863**	**$ 13,933,817**	**$ 101,857,542**
52								
53	**Subtotal Energy Charge and Peak Capacity Charge**							
54								
55	**TOTAL Revenue**			**$ 90,557,004**			**$ 14,392,626**	**$ 104,949,630**
56								
57	**Summary of Revenue**							
58	Customer Charge			$ 2,633,279			$ 458,809	$ 3,092,088
59	Demand Charge			-			-	-
60	Energy Charge			87,923,725			13,933,817	101,857,542
61	**Total Revenue**			**$ 90,557,004**			**$ 14,392,626**	**$ 104,949,630**
62	*Check*							

Austin Energy
Rate Benchmarking Analysis
Exhibit 6 - Reliant-CenterPoint

(A)	(B)	(Q)		(R)		(S)	(T)		(U)		(V)		(W)
		Relaint/CenterPoint Structure w Reliant/CenterPoint Revenue Requirement											
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)					Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)						Total Reliant/CenterPoint Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)
Line No.	Item	Billing Units		Rate		Revenues	Billing Units		Rate		Revenues		Total Revenues
38	**Reliant/CenterPoint Rate Schedule**												
39													
40	Base Charge												
41	Reliant Usage Charge (months)	138,187	$	9.95	$	1,374,961	24,077	$	9.95	$	239,566	$	1,614,527
42	CenterPoint Delivery Charge (months)	138,187	$	8.52	$	1,177,353	24,077	$	8.52	$	205,136	$	1,382,489
43	**Base Charge**		**$**	**18.47**	**$**	**2,552,314**		**$**	**18.47**	**$**	**444,702**	**$**	**2,997,016**
44													
45	**Demand Charge (kW)**	**2,889,476**	**$**	**-**	**$**	**-**	**504,659**	**$**	**-**	**$**	**-**	**$**	**-**
46													
47													
48	Energy Charge (kWh)												
49	Reliant Energy Charge (kWh)	741,168,960	$	0.07400	$	54,846,503	117,457,635	$	0.07400	$	8,691,865	$	63,538,368
50	CenterPoint Energy Charge (kWh)	741,168,960	$	0.04098	$	30,373,845	117,457,635	$	0.04098	$	4,813,531	$	35,187,376
51	**Subtotal Energy Charge**		**$**	**0.11498**	**$**	**85,220,348**		**$**	**0.11498**	**$**	**13,505,396**	**$**	**98,725,745**
52													
53	**Subtotal Energy Charge and Peak Capacity Charge**												
54													
55	**TOTAL Revenue**				**$**	**87,772,662**				**$**	**13,950,099**	**$**	**101,722,761**
56													
57	**Summary of Revenue**												
58	Customer Charge				$	2,552,314				$	444,702	$	2,997,016
59	Demand Charge					-					-		-
60	Energy Charge					85,220,348					13,505,396		98,725,745
61	**Total Revenue**				**$**	**87,772,662**				**$**	**13,950,099**	**$**	**101,722,761**
62	*Check*												

EXHIBIT 7
Rate Benchmarking Analysis - SMUD

Austin Energy
Rate Benchmarking Analysis
Exhibit 7 - SMUD

Proof of Revenue

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL)			Austin Energy Secondary Voltage ≥ 10 < 50 kW (OCL)			Total Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
1								
2	**Austin Energy Rate Schedule**							
3								
4	**Customer Charge (months)**	**138,187**	**$ 25.00**	**$ 3,454,675**	**24,077**	**$ 25.00**	**$ 601,925**	**$ 4,056,600**
5								
6	Demand Charges							
7	Winter ($/kW-billed)	1,877,111	$ 5.15	9,667,124	339,867	$ 5.12	1,740,119	11,407,243
8	Summer ($/kW-billed)	1,012,365	$ 6.15	6,226,042	164,792	$ 6.11	1,006,881	7,232,923
9	Subtotal Demand Charges		$ 5.48	$ 15,893,166		$ 5.45	$ 2,747,000	$ 18,640,166
10								
11	Electric Delivery ($/kW-billed)	2,889,476	$ 4.00	11,557,904	504,659	$ 3.98	2,008,544	13,566,448
12	Regulatory Charge ($/kW)	2,889,476	$ 2.56	7,397,059	504,659	$ 2.56	1,291,928	8,688,986
13	Temporary Supplemental Charge (OCL)	2,889,476	$ -	-	504,659	$ 0.13	65,606	65,606
14	**Subtotal Demand Charges and Adjustment Charges**		**$ 6.56**	**$ 34,848,129**		**$ 12.12**	**$ 6,113,077**	**$ 40,961,206**
15								
16	Energy Charge (kWh)							
17	Winter Energy (kWh)	433,209,672	$ 0.02414	10,457,681	70,674,283	$ 0.02399	1,695,476	12,153,158
18	Summer Energy (kWh)	307,959,288	$ 0.02914	8,973,934	46,783,352	$ 0.02896	1,354,846	10,328,780
19	Subtotal Energy Charge		$ 0.02581	$ 19,431,615		$ 0.02565	$ 3,050,322	$ 22,481,937
20								
21	FAC or PSA (kWh)	741,168,960	$ 0.03709	27,489,957	117,457,635	$ 0.03709	4,356,504	31,846,460
22	Customer Assistance Program ($/kWh)	741,168,960	$ 0.00065	481,760	117,457,635	$ 0.00065	76,347	558,107
23	Service Area Street Lighting ($/kWh)	741,168,960	$ 0.00076	563,288	117,457,635	$ -	-	563,288
24	Energy Efficiency Services ($/kWh)	741,168,960	$ 0.00522	3,868,902	117,457,635	$ 0.00522	613,129	4,482,031
25	Transmission Service Adjustment	741,168,960	$ -	-	117,457,635	$ -	-	-
26	**Subtotal Energy Charge and Adjustment Charges**		**$ 0.06953**	**$ 51,835,522**		**$ 0.06861**	**$ 8,096,302**	**$ 59,931,824**
27								
28	**TOTAL Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
29	*Check*							
30	**Summary of Revenue**							
31	Customer Charge			$ 3,454,675			$ 601,925	$ 4,056,600
32	Demand Charge			34,848,129			6,113,077	40,961,206
33	Energy Charge			51,835,522			8,096,302	59,931,824
34	**Total Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
35	*Check*							
36								
37								

Austin Energy
Rate Benchmarking Analysis
Exhibit 7 - SMUD

(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
		SMUD Structure w AE Revenue Requirement						
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)			**Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Sacramento Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
38	**SMUD Power Rate Schedule**							
39	***Small Non-Demand Service <20kW***							
40	Customer Charge (months)							
41	Winter (Oct - May)	50,846	$ 15.95	$ 810,779	8,673	$ 15.95	$ 138,298	$ 949,077
42	Summer (June - Sept)	27,950	$ 15.95	$ 445,685	5,254	$ 15.95	$ 83,779	$ 529,464
43	Customer Charge	78,796	**$ 15.95**	**$ 1,256,464**	13,927	**$ 15.95**	**$ 222,077**	**$ 1,478,541**
44								
45	**Demand Charge (kW)**	**2,889,476**	**$ -**	**$ -**	**183,865**	**$ -**	**$ -**	**$ -**
46								
47	Energy Charge (kWh)							
48	On-peak (Summer Weekdays 1500-1800)	9,467,513	$ 0.28523	$ 2,700,421	1,656,476	$ 0.28523	$ 472,477	$ 3,172,898
49	Off-peak (All Other Hours)	226,743,147	$ 0.10714	$ 24,292,297	38,312,459	$ 0.10714	$ 4,104,634	$ 28,396,930
50	**Subtotal Energy Charges**	236,210,660	$ 0.1103	**$ 26,992,718**	39,968,935	$ 0.1103	**$ 4,577,111**	**$ 31,569,829**
51								
52	**Subtotal Small Non-Demand Service <20kW**			**$ 28,249,182**			**$ 4,799,188**	**$ 33,048,370**
53								
54	***Small Demand Service 21kw - 299kW, min of 7,300 kWh for 3 consecutive months***							
55	Customer Charge (months)							
56	Winter (Oct - May)	78,796	$ 23.02	$ 1,814,020	13,927	$ 23.02	$ 320,624	$ 2,134,644
57	Summer (June - Sept)	20,219	$ 23.02	$ 465,476	3,082	$ 23.02	$ 70,953	$ 536,429
58	**Customer Charge**	99,015	**$ 23.02**	**$ 2,279,496**	17,009	**$ 23.02**	**$ 391,577**	**$ 2,671,073**
59								
60	Demand Charge (kW)							
61	Site Infrastructure Charge	1,842,420	$ 7.12	$ 13,110,304	319,874	$ 7.12	$ 2,276,161	$ 15,386,465
62	Subtotal Demand Charge		**$ 7.1158**	**$ 13,110,304**		**$ 7.1158**	**$ 2,276,161**	**$ 15,386,465**
63								
64	Energy Charge (kWh)							
65	On-peak (Summer Weekdays 1500-1800)	20,082,640	$ 0.24467	$ 4,913,582	2,821,312	$ 0.24467	$ 690,285	$ 5,603,868
66	Off-peak (All Other Hours)	483,166,476	$ 0.08491	$ 41,026,298	74,481,562	$ 0.08491	$ 6,324,327	$ 47,350,625
67	Subtotal Energy Charges	503,249,117	$ 0.0878	$ 45,939,880	77,302,874	$ 0.0878	$ 7,014,612	$ 52,954,492
68								
69	Solar Surcharge (kWh)	503,249,117	$ 0.00149	$ 752,316	77,302,874	$ 0.00149	$ 115,561	$ 867,877
70	Hydro Generation Adjustment (kWh)	503,249,117	$ -	$ -	77,302,874	$ -	$ -	$ -
71	Subtotal Energy Charges and Adjustment Charges		**$ 0.0893**	**$ 46,692,196**		**$ 0.0893**	**$ 7,130,173**	**$ 53,822,370**
72								
73	Power Factor Adjustment (kVar)	1,824,901	$ 0.01027	$ 18,733	255,208	$ 0.01027	$ 2,620	$ 21,353
74								
75	**Subtotal Small Demand Service 21kw - 299kW Customer Revenue**			**$ 62,100,730**			**$ 9,800,531**	**$ 71,901,260**
76								
77	**TOTAL Customer Revenue**			**$ 90,349,911**			**$ 14,599,719**	**$ 104,949,630**
78								
79	**Summary of Revenue**							
80	Customer Charge			$ 3,535,961			$ 613,654	$ 4,149,614
81	Demand Charge			13,110,304			2,276,161	15,386,465
82	Energy Charge			73,684,914			11,707,285	85,392,198
83	Power Factor Adjustment			18,733			2,620	21,353
84	**Total Revenue**			**$ 90,349,911**			**$ 14,599,719**	**$ 104,949,630**
85	*Check*							

Austin Energy
Rate Benchmarking Analysis
Exhibit 7 - SMUD

(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)
		SMUD Structure w SMUD Revenue Requirement						
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)			**Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Sacramento Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
38	**SMUD Power Rate Schedule**							
39	***Small Non-Demand Service <20kW***							
40	Customer Charge (months)							
41	Winter (Oct - May)	50,846	$ 16.00	$ 813,536	8,673	$ 16.00	$ 138,768	$ 952,304
42	Summer (June - Sept)	27,950	$ 16.00	$ 447,200	5,254	$ 16.00	$ 84,064	$ 531,264
43	Customer Charge	78,796	**$ 16.00**	**$ 1,260,736**	13,927	**$ 16.00**	**$ 222,832**	**$ 1,483,568**
44								
45	**Demand Charge (kW)**	**2,889,476**	**$ -**	**$ -**	**183,865**	**$ -**	**$ -**	**$ -**
46								
47	Energy Charge (kWh)							
48	On-peak (Summer Weekdays 1500-1800)	9,467,513	$ 0.28620	$ 2,709,602	1,656,476	$ 0.28620	$ 474,084	$ 3,183,686
49	Off-peak (All Other Hours)	226,743,147	$ 0.10750	$ 24,374,888	38,312,459	$ 0.10750	$ 4,118,589	$ 28,493,478
50	**Subtotal Energy Charges**	236,210,660	$ 0.1107	**$ 27,084,491**	39,968,935	$ 0.1107	**$ 4,592,673**	**$ 31,677,163**
51								
52	**Subtotal Small Non-Demand Service <20kW**			**$ 28,345,227**			**$ 4,815,505**	**$ 33,160,731**
53								
	Small Demand Service 21kw - 299kW, min of 7,300 kWh							
54	***for 3 consecutive months***							
55	Customer Charge (months)							
56	Winter (Oct - May)	78,796	$ 23.10	$ 1,820,188	13,927	$ 23.10	$ 321,714	$ 2,141,901
57	Summer (June - Sept)	20,219	$ 23.10	$ 467,059	3,082	$ 23.10	$ 71,194	$ 538,253
58	**Customer Charge**	99,015	**$ 23.1000**	**$ 2,287,247**	17,009	**$ 23.1000**	**$ 392,908**	**$ 2,680,154**
59								
60	Demand Charge (kW)							
61	Site Infrastructure Charge	1,842,420	$ 7.14	$ 13,154,878	319,874	$ 7.14	$ 2,283,900	$ 15,438,778
62	Subtotal Demand Charge		$ 7.14	**$ 13,154,878**		$ 7.14	**$ 2,283,900**	**$ 15,438,778**
63								
64	Energy Charge (kWh)							
65	On-peak (Summer Weekdays 1500-1800)	20,082,640	$ 0.24550	$ 4,930,288	2,821,312	$ 0.24550	$ 692,632	$ 5,622,920
66	Off-peak (All Other Hours)	483,166,476	$ 0.08520	$ 41,165,784	74,481,562	$ 0.08520	$ 6,345,829	$ 47,511,613
67	Subtotal Energy Charges	503,249,117	$ 0.0881	$ 46,096,072	77,302,874	$ 0.0881	$ 7,038,461	$ 53,134,533
68								
69	Solar Surcharge (kWh)	503,249,117	$ 0.00150	$ 754,874	77,302,874	$ 0.00150	$ 115,954	$ 870,828
70	Hydro Generation Adjustment (kWh)	503,249,117	$ -	$ -	77,302,874	$ -	$ -	$ -
71	Subtotal Energy Charges and Adjustment Charges		$ 0.0896	**$ 46,850,946**		$ 0.0896	**$ 7,154,415**	**$ 54,005,361**
72								
73	Power Factor Adjustment (kVar)	1,824,901	$ 0.0103	$ 18,796	255,208	$ 0.0103	$ 2,629	**$ 21,425**
74								
	Subtotal Small Demand Service 21kw - 299kW							
75	**Customer Revenue**			**$ 62,311,867**			**$ 9,833,852**	**$ 72,145,719**
76								
77	**TOTAL Customer Revenue**			**$ 90,657,094**			**$ 14,649,357**	**$ 105,306,450**
78								
79	**Summary of Revenue**							
80	Customer Charge			$ 3,547,983			$ 615,740	$ 4,163,722
81	Demand Charge			13,154,878			2,283,900	15,438,778
82	Energy Charge			73,935,436			11,747,088	85,682,525
83	Power Factor Adjustment			18,796			2,629	21,425
84	**Total Revenue**			**$ 90,657,094**			**$ 14,649,357**	**$ 105,306,450**
85	*Check*							

EXHIBIT 8
Rate Benchmarking Analysis – TXU

Austin Energy
Rate Benchmarking Analysis
Exhibit 8 - TXU-Oncor

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Proof of Revenue						
		Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL)			**Austin Energy Secondary Voltage ≥ 10 < 50 kW (OCL)**			**Total Austin Energy Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
1								
2	**Austin Energy Rate Schedule**							
3								
4	**Customer Charge (months)**	**138,187**	**$ 25.00**	**$ 3,454,675**	**24,077**	**$ 25.00**	**$ 601,925**	**$ 4,056,600**
5								
6	Demand Charges							
7	Winter ($/kW-billed)	1,877,111	$ 5.15	9,667,124	339,867	$ 5.12	1,740,119	11,407,243
8	Summer ($/kW-billed)	1,012,365	$ 6.15	6,226,042	164,792	$ 6.11	1,006,881	7,232,923
9	Subtotal Demand Charges		$ 5.48	$ 15,893,166		$ 5.45	$ 2,747,000	$ 18,640,166
10								
11	Electric Delivery ($/kW-billed)	2,889,476	$ 4.00	11,557,904	504,659	$ 3.98	2,008,544	13,566,448
12	Regulatory Charge ($/kW)	2,889,476	$ 2.56	7,397,059	504,659	$ 2.56	1,291,928	8,688,986
13	Temporary Supplemental Charge (OCL)	2,889,476	$ -	-	504,659	$ 0.13	65,606	65,606
14	**Subtotal Demand Charges and Adjustment Charges**		**$ 12.04**	**$ 34,848,129**		**$ 12.12**	**$ 6,113,077**	**$ 40,961,206**
15								
16	Energy Charge (kWh)							
17	Winter Energy (kWh)	433,209,672	$ 0.02414	10,457,681	70,674,283	$ 0.02399	1,695,476	12,153,158
18	Summer Energy (kWh)	307,959,288	$ 0.02914	8,973,934	46,783,352	$ 0.02896	1,354,846	10,328,780
19	**Subtotal Energy Charge**		$ 0.02581	**$ 19,431,615**		$ 0.02565	**$ 3,050,322**	**$ 22,481,937**
20								
21	FAC or PSA (kWh)	741,168,960	$ 0.03709	27,489,957	117,457,635	$ 0.03709	4,356,504	31,846,460
22	Customer Assistance Program ($/kWh)	741,168,960	$ 0.00065	481,760	117,457,635	$ 0.00065	76,347	558,107
23	Service Area Street Lighting ($/kWh)	741,168,960	$ 0.00076	563,288	117,457,635	$ -	-	563,288
24	Energy Efficiency Services ($/kWh)	741,168,960	$ 0.00522	3,868,902	117,457,635	$ 0.00522	613,129	4,482,031
25	Transmission Service Adjustment	741,168,960	$ -	-	117,457,635	$ -	-	-
26	**Subtotal Energy Charge and Adjustment Charges**		**$ 0.06953**	**$ 51,835,522**		**$ 0.06861**	**$ 8,096,302**	**$ 59,931,824**
27								
28	**TOTAL Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
29	*Check*							
30	**Summary of Revenue**							
31	Customer Charge			$ 3,454,675			$ 601,925	$ 4,056,600
32	Demand Charge			34,848,129			6,113,077	40,961,206
33	Energy Charge			51,835,522			8,096,302	59,931,824
34	**Total Revenue**			**$ 90,138,326**			**$ 14,811,304**	**$ 104,949,630**
35	*Check*							
36								
37								

Austin Energy
Rate Benchmarking Analysis
Exhibit 8 - TXU-Oncor

(A)	(B)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
		TXU/Oncor Structure w AE Revenue Requirement						
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)			Commecial Secondary Voltage ≥ 10 < 50 kW (OCL)			Total TXU/Oncor Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)
Line No.	Item	Billing Units	Rate	Revenues	Billing Units	Rate	Revenues	Total Revenues
38	**TXU/Oncor Rate Schedule**							
39								
40	Customer Charge							
41	Base Charge (months)	138,187	$ 9.10	$ 1,257,396	24,077	$ 9.10	$ 219,082	$ 1,476,479
42	Oncor Customer Charge (months)	138,187	$ 30.11	$ 4,160,149	24,077	$ 30.11	$ 724,843	$ 4,884,992
43	**Subtotal Customer Charge**		**$ 39.20**	**$ 5,417,545**		**$ 39.20**	**$ 943,926**	**$ 6,361,471**
44								
45	Demand Charge (kW)							
46	Distribution Demand Charge	2,889,476	$ 7.64	$ 22,080,145	504,659	$ 7.64	$ 3,856,391	$ 25,936,536
47	**Subtotal Demand Charge**			**$ 22,080,145**			**$ 3,856,391**	**$ 25,936,536**
48								
49								
50	Energy Charge (kWh)							
51	Energy Charge	741,168,960	$ 0.0841	$ 62,357,248	117,457,635	$ 0.0841	$ 9,882,139	$ 72,239,388
52	Oncor Consumption Charge	741,168,960	$ 0.0005	$ 355,843	117,457,635	$ 0.0005	$ 56,393	$ 412,236
53	Subtotal Energy Charge		$ 0.0846	$ 62,713,091		$ 0.0846	$ 9,938,532	$ 72,651,623
54								
55	**Subtotal Energy Charge and Peak Capacity Charge**			**$ 62,713,091**			**$ 9,938,532**	**$ 72,651,623**
56								
57	**TOTAL Revenue**			**$ 90,210,781**			**$ 14,738,849**	**$ 104,949,630**
58								
59	**Summary of Revenue**							
60	Customer Charge			$ 5,417,545			$ 943,926	$ 6,361,471
61	Demand Charge			22,080,145			3,856,391	25,936,536
62	Energy Charge			62,713,091			9,938,532	72,651,623
63	**Total Revenue**			**$ 90,210,781**			**$ 14,738,849**	**$ 104,949,630**
64	*Check*							

Austin Energy
Rate Benchmarking Analysis
Exhibit 8 - TXU-Oncor

(A)	(B)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)
		TXU/Oncor Structure w TXU/Oncor Revenue Requirement						
		Commecial Secondary Voltage ≥ 10 < 50 kW (ICL)			**Commecial Secondary Voltage ≥ 10 < 50 kW OCL)**			**Total TXU/Oncor Secondary Voltage ≥ 10 < 50 kW (ICL & OCL)**
Line No.	**Item**	**Billing Units**	**Rate**	**Revenues**	**Billing Units**	**Rate**	**Revenues**	**Total Revenues**
38	**TXU/Oncor Rate Schedule**							
39								
40	Customer Charge							
41	Base Charge (months)	138,187	$ 9.95	$ 1,374,961	24,077	$ 9.95	$ 239,566	$ 1,614,527
42	Oncor Customer Charge (months)	138,187	$ 32.92	$ 4,549,116	24,077	$ 32.92	$ 792,615	$ 5,341,731
43	**Subtotal Customer Charge**		**$ 42.87**	**$ 5,924,077**		**$ 42.87**	**$ 1,032,181**	**$ 6,956,258**
44								
45	Demand Charge (kW)							
46	Distribution Demand Charge	2,889,476	$ 8.36	$ 24,144,600	504,659	$ 8.36	$ 4,216,957	$ 28,361,557
47	**Subtotal Demand Charge**			**$ 24,144,600**			**$ 4,216,957**	**$ 28,361,557**
48								
49								
50	Energy Charge (kWh)							
51	Energy Charge	741,168,960	$ 0.09200	$ 68,187,544	117,457,635	$ 0.09200	$ 10,806,102	$ 78,993,647
52	Oncor Consumption Charge	741,168,960	$ 0.00053	$ 389,114	117,457,635	$ 0.00053	$ 61,665	$ 450,779
53	Subtotal Energy Charge		$ 0.0925	$ 68,576,658		$ 0.0925	$ 10,867,768	$ 79,444,426
54								
55	**Subtotal Energy Charge and Peak Capacity Charge**			**$ 68,576,658**			**$ 10,867,768**	**$ 79,444,426**
56								
57	**TOTAL Revenue**			**$ 98,645,335**			**$ 16,116,906**	**$ 114,762,241**
58								
59	**Summary of Revenue**							
60	Customer Charge			$ 5,924,077			$ 1,032,181	$ 6,956,258
61	Demand Charge			24,144,600			4,216,957	28,361,557
62	Energy Charge			68,576,658			10,867,768	79,444,426
63	**Total Revenue**			**$ 98,645,335**			**$ 16,116,906**	**$ 114,762,241**
64	*Check*							

Appendix A
Rate Schedules Used in Benchmarking Analysis

BEC

Rate	Wholesale Charge	Distribution Charge	Monthly Minimum Charge	Description
General Service	$0.064571 per kWh	$0.028509 per kWh	$22.50 per month	This includes residential farm, residential non-farm, rural recreation, churches, parsonages, and schools.
Commercial	$0.064571 per kWh	Single - Phase $0.034940 per kWh Three - Phase $0.036840 per kWh	Single - Phase: $30.00 per month Three - Phase: $50.00 per month	Available to all commercial and industrial consumers and other consumers whose electric requirments for all uses are less than 50 kW.
Large Power	$0.064571 per kWh	$0.015829 per kWh $4.50 per kW (minimum 50 kW)	$75.00 per month	Available to all commercial and industrial consumers whose electric requirements for all uses are 50kW to 250 kW.
Large Power> 250 kW	$0.064571 per kWh	$0.010139 per kWh $5.50 per kW (minimum 250 kW)	$150.00 per month	Available to all commercial and industrial consumers whose electric requirements for all uses are greater than 250kW.
Pumping Service	$0.064571 per kWh	$0.044617 per kWh	$55.00 per month	Applies to all pumping installations to which a specific rate is not applicable.
Lighting Service	See below	See below		Applies to electric service for dusk-to-dawn lighting to members.
Public Lighting	$0.064571 per kWh	$0.123143 per kWh	$30.00 per month*	Applies to metered electric service for lighting public thoroughfares and traffic lights for a term not less than one year.

* Also includes a maintenance charge, where lights are to be furnished or paid for by the member at the next regular billing.

Lighting Service Rate:

Un-Metered Installations		
53 Watt LED	@	$10.37 per month per light
94 Watt LED	@	$14.61 per month per light
140 Watt LED	@	$19.72 per month per light
175 Watt Mercury Vapor	@	$10.37 per month per light
100 Watt Hi-Pressure Sodium	@	$10.37 per month per light
250 Watt Hi-Pressure Sodium	@	$14.61 per month per light
400 Watt Hi-Pressure Sodium	@	$19.72 per month per light
Metered Installations		
175 Watt Mercury Vapor	@	$5.53 per month per light
53 Watt LED	@	$9.08 per month per light
94 Watt LED	@	$12.16 per month per light
140 Watt LED	@	$16.10 per month per light
175 Watt Mercury Vapor	@	$5.53 per month per light
100 Watt Hi-Pressure Sodium	@	$7.46 per month per light
250 Watt Hi-Pressure Sodium	@	$8.15 per month per light
400 Watt Hi-Pressure Sodium	@	$9.39 per month per light

Note: All rates are subject to change, and are subject to all billing adjustments, including but not limited to franchise fees (where applicable).

Revised 09/02/2014

CPS Energy

GENERAL SERVICE

BASE COMMERCIAL ELECTRIC RATE

PL

APPLICATION

This rate is applicable to alternating current service, for which no specific rate is provided, to any Customer whose entire requirements on the premises are supplied at one point of delivery through one meter.

This rate is not applicable (a) when another source of electric energy is used by the Customer or (b) when another source of energy (other than electric) is used for the same purpose or an equivalent purpose as the electric energy furnished directly by CPS Energy, except that such other source of energy as mentioned in (a) and (b) may be used during temporary failure of the CPS Energy electric service.

This rate is not applicable to emergency, standby, or shared service. It also is not applicable to resale service except that submetering will be permitted under this rate only for the purpose of allocating the monthly bill among the tenants served through a master meter in accordance with CPS Energy Rules and Regulations Applying to Retail Electric & Gas Service.

TYPE OF SERVICE

The types of service available under this rate are described in CPS Energy Electric Service Standards. When facilities of adequate capacity and suitable phase and voltage are not adjacent to the premises served or to be served, the required service may be provided pursuant to CPS Energy Rules and Regulations Applying to Retail Electric & Gas Service and the CPS Energy Policy for Electric Line Extensions and Service Installations.

MONTHLY BILL

Rate

$ 8.75	Service Availability Charge
	Energy Charge
$ 0.0719	Per KWH for the first 1600 KWH*
$ 0.0332	Per KWH for all additional KWH
	Peak Capacity Charge
	Summer Billing (June - September)
$ 0.0198	Per KWH for all KWH in excess of 600 KWH
	Non-Summer Billing (October - May)
$ 0.0100	Per KWH for all KWH in excess of 600 KWH

*200 KWH are added for each KW of Billing Demand in excess of 5 KW.

Minimum Bill

$8.75 plus $4.00 per KW of Billing Demand in excess of 5 KW. A higher Minimum Bill may be specified in the Customer's Application and Agreement for Electric Service. The Minimum Bill is not subject to reduction by credits allowed under the adjustments below.

Adjustments

Plus or minus an amount which reflects the difference in the unit fuel cost factor for the current month above or below a basic cost of $0.01416 per KWH sold. The unit fuel cost factor for the current month is computed as the sum of:

(a) The current month's estimated unit fuel cost per KWH, which is computed based upon the current month's estimated KWH generation mix, unit fuel cost by fuel type, any known changes in fuel cost, sales to other than long-term customers, purchases and line losses; plus

(b) An adjustment, if indicated by the current status of the over and under recovery of fuel costs for the recovery year in progress, to correct for the difference between the preceding month's estimated unit fuel cost and the current computation for this value. This adjustment is computed by multiplying the difference between the preceding month's estimated unit fuel cost (corrected for any fuel supplier surcharge) and the current computation for this value times the KWH generated during the preceding month and then dividing the result by the current month's estimated KWH sales; plus

(c) An adjustment, if indicated by the current status of the over and under recovery of fuel costs for the recovery year in progress, to correct for the difference between the preceding month's estimated value for the second preceding month's unit fuel cost and actual unit fuel cost for that month. This adjustment is computed by multiplying the difference between the preceding month's estimated value for the second preceding month's unit fuel cost and the actual unit fuel cost for that month (corrected for any fuel supplier surcharge) times the KWH generated during the preceding month and then dividing the result by the current month's estimated KWH sales; plus

(d) An adjustment, as necessary, which may be derived and applied to the unit fuel cost factors during the months preceding, including, and/or following January each year, depending on the dollar amount of adjustment necessary to balance the annual cumulative actual fuel cost with the annual cumulative fuel cost recovery through these rates; plus

(e) An adjustment to reflect offsetting credits to or additions to fuel costs resulting from judicial orders or settlements of legal proceedings affecting fuel costs or components thereof, including taxes or transportation costs, or to reflect accounting and billing record corrections or other out-of-period adjustments to fuel costs.

(f) An adjustment, as necessary, which may be derived and applied to the unit fuel cost factors for recovery of dollars spent for the verifiable kW reductions that are above the level reflected in base rates for energy efficiency and conservation programs. Recovery of such costs would be allowed once an independent third party reviews and confirms the incremental kW reductions.

Plus or minus the proportionate part of the increase or decrease in taxes, required payments to governmental entities or for governmental or municipal purposes which may be hereafter assessed, imposed, or otherwise required and which are payable out of or are based upon revenues of the electric system.

Monthly Demand

The Demand will be the KW as determined from the reading of the CPS Energy demand meter for the 15 minute period of the Customer's greatest Demand reading during the month.

Billing Demand

For the period June through September, the Billing Demand is equal to the Monthly Demand as defined above. For the period October through May, the Billing Demand is equal to the Monthly Demand or 80% of the highest measured demand established during the previous summer period months (June through September), whichever is greater.

Prior to the establishment of a previous summer peak Demand, the Billing Demand shall be equal to the Monthly Demand as defined above.

Power Factor

When, based on a test of the Customer's power factor, the power factor is below 85% lagging, the Billing Demand may be increased by adding 1% of the Actual Demand for each 1% that the power factor is below 85%.

High Voltage Discount

This discount applies only to electric service supplied at CPS Energy nominal distribution voltage of 13.2 KV or higher, when (a) such service voltage requires no more than one (1) step down transformation from transmission voltage of 69 KV or higher, and when (b) such service can be supplied in accordance with CPS Energy distribution system design criteria.

For service supplied under this discount, the Energy Charge per KWH for usage up to 200 KWH per KW of Billing Demand will be discounted by $0.00225 per KWH. The Customer must be demand metered and must own and maintain at Customer expense all other transformers and facilities that might be required to utilize this service.

LATE PAYMENT CHARGE

The Monthly Bill will be charged if payment is made within the period indicated on the bill. Bills not paid within this period will be charged an additional 2 percent times the Monthly Bill excluding the adjustment for fuel costs, garbage fees and sales taxes.

TERM OF SERVICE

The Term of Service shall be in accordance with the CPS Energy Application and Agreement for Electric Service. Should a Customer's service requirement exceed the standard of service normally provided under this rate, a longer contract term may be required.

RULES AND REGULATIONS

Service is subject to CPS Energy Rules and Regulations Applying to Retail Electric & Gas Service which are incorporated herein by this reference.

CURTAILMENT

CPS Energy shall have the right at any and all times to immediately adjust in whole or in part, the supply of electricity to Customers, in order to adjust to fuel supplies for generation of electricity or to adjust to other factors affecting delivery capability.

Sec. 26-466. General service, schedule GS.

(a) Availability. The schedule GS shall be available within the corporate limits of the City and the suburban fringe.

(b) Applicability.

(1) This schedule applies to individual commercial and industrial services, served at the established secondary voltage of the City's distribution system; and optionally, for apartments and multiple dwellings in existence prior to January 1, 1980, where more than one (1) dwelling or single living quarters are served through one (1) meter. Single-phase motors from one (1) to five (5) horsepower may be connected with the approval of the utility. This schedule applies to an individual single- or three-phase service with an energy-only meter and for demand metered services with an average metered demand of not greater than twenty-five (25) kilowatts.

(2) This schedule does not apply to single-family, individually metered residential units unless:

a. the energy delivered to such a unit is also used for commercial or business use and the commercial/business energy use comprises more than fifty (50) percent of the total energy use for the unit; and

b. the unit is not eligible for a Home Occupation License as specified in Article 3 of the Land Use Code.

(c) Monthly rate. The monthly rates for this schedule are as follows:

(1) Fixed charge, per account:

a. Single-phase, two-hundred-ampere service: three dollars and twenty-six cents ($3.26).

b. Single-phase, above two-hundred-ampere service: nine dollars and sixty cents ($9.60).

c. Three-phase, two-hundred-ampere service: four dollars and ninety-six cents ($4.96).

d. Three-phase, above two-hundred-ampere service: eleven dollars and seventy-four cents ($11.74).

(2) Demand charge, per kilowatt hour:

a. During the summer season billing months of June, July and August: two and seventy-seven one-hundredths cents ($0.0277).

b. During the non-summer season billing months of January through May and September through December: one and forty-nine one-hundredths cents ($0.0149).

c. The meter reading date shall generally determine the summer season billing months; however, no customer shall be billed more than three (3) full billing cycles at the summer rate.

(3) Distribution facilities charge, per kilowatt hour: two and twenty-seven one-hundredths cents ($0.0227).

(4) Energy charge, per kilowatt hour:

a. During the summer season billing months of June, July and August: four and sixteen one-hundredths cents ($0.0416).

b. During the non-summer season billing months of January through May and September through December: four and zero one-hundredths cents ($0.0400).

c. The meter reading date shall generally determine the summer season billing months; however, no customer shall be billed more than three (3) full billing cycles at the summer rate.

(5) In lieu of taxes and franchise: a charge at the rate of six and zero-tenths (6.0) percent of all monthly service charges billed pursuant to this Section.

(d) Renewable resource. Renewable energy resources, including, but not limited to, energy generated by the power of wind, may be offered on a voluntary basis to customers at a premium of two and four-tenths cents ($0.024) per kilowatt hour. The utility may establish and offer voluntary programs designed to increase and enhance the use of energy generated by renewable energy resources in support of Council-adopted policy applicable to the utility.

(e) Excess capacity charge. A monthly capacity charge of two dollars ($2.) per kilowatt may be added to the above charges for service to intermittent loads in accordance with the provisions of the electric service rules and regulations.

(f) Service charge. Service charges and connection fees shall be as set forth in Subsection 26-712(b).

(g) Conservation assistance, rebates and incentives. The utility may establish programs to assist customers or provide incentives to customers in order to reduce energy consumption or system peak demands consistent with Council-adopted policy applicable to the utility. Such programs may include financial or technical assistance, incentives or rebates and shall be consistent with program objectives approved by the Utilities Executive Director.

(h) Billing demand. The billing demand shall be determined for each point of delivery by suitable meter measurement of the highest fifteen-minute integrated demand occurring during the billing period.

(i) Power factor adjustment. Power factor shall be determined by using watt and volt-ampere measurements collected by the electric meter at the point of service. The power factor calculated from such measurements shall be the basis of billing adjustment until satisfactory correction has been made. Review shall be conducted on a monthly basis by the utility. If the power factor falls below ninety-percent lagging, a power factor adjustment may be made by increasing the billing demand by one (1) percent for each one (1) percent or fraction thereof by which the power factor is less than ninety-percent lagging. This adjustment shall be based on the power factor at the time of maximum demand as recorded during the billing period.

(j) Service rights fee in certain annexed areas. A fee for defraying the cost of acquisition of service rights from Poudre Valley Rural Electric Association (PVREA) shall be charged for each service in areas annexed into the City after April 22, 1989, if such area was previously served by PVREA. The service rights will be collected monthly for a period of ten (10) consecutive years following the date of acquisition by the City of electric facilities in such area from PVREA. If service was previously provided by PVREA, the fee shall be twenty-five (25) percent of charges for electric power service. For services that come into existence in the affected area after date of acquisition, the fee shall be five (5) percent of charges for electric power service. In the event that the City Council has determined that a reduction of the service rights fee is justified in order to mitigate the economic impacts to a lot or parcel of land at the time of annexation of said lot or parcel of land, the service rights fee charged pursuant to this Subsection may be reduced by the City Council pursuant to a schedule set forth in the ordinance annexing said parcel or lot. The service rights fee charged pursuant to this Subsection shall not be subject to a charge in lieu of taxes and franchise otherwise required in this Section.

(k) Special services. Special services or complex service arrangements that are beyond those required for service under this rate schedule may be arranged by a written services agreement that the Utilities Executive Director may negotiate and enter into on behalf of the utility. Said agreement shall establish the terms and conditions for any special services or arrangements and shall incorporate by reference the requirements of this Chapter, as applicable. Any special services agreement modifying the rates, fees or charges for said services from those set forth in this Article shall be subject to approval by the City Council in accordance with Section 6 of Article XII of the Charter.

(l) Parallel generation. Customers may operate all or part of their instantaneous energy or capacity needs by operation of a qualifying facility in parallel with the utility system, provided that electric service is being rendered under the special services provisions of this schedule, and provided further that such facility is constructed, operated and maintained in accordance with the provisions of the electric service rules and regulations. The credit for the energy delivered to the electric utility under this provision shall be provided at applicable Platte River Power Authority avoided cost rates. If a customer is receiving net metering service, such customer's service shall also be governed by the net metering service terms and conditions described in Subsection (q) below, and the credit for energy delivered to the electric utility shall be calculated as described in that Subsection.

(m) Commodity delivery. If the electric utility authorizes the delivery of electric capacity or energy utilizing the utility's distribution system under mandatory provisions of state or federal law, a credit will be applied to the customer's monthly electric bill based upon the electric utility's displaced costs as credited to the utility by its supplier of electric energy. Capacity, energy, standby capacity, backup capacity and special services shall be delivered, metered, billed, dispatched and controlled in accordance with a special services agreement with the electric utility.

(n) Payment of charges. Due dates and delinquency procedures shall be as set forth in § 26-713.

(o) Contract period. The applicant shall take electric service under this or any other applicable schedule which is in effect during the term of the contract subject to adjustment from time to time by the City Council. All contracts under this schedule shall be for twelve (12) months and shall be automatically renewed annually. The contract may be terminated at the end of the term upon the giving of ten (10) days' advance written notice to the City or may be terminated upon the giving of ten (10) days' advance written notice to the City in the event of vacation of the premises or a change in ownership or tenant occupancy status.

(p) Rules and regulations. Service supplied under this schedule is subject to the terms and conditions set forth in the electric utility rules and regulations as approved by the City Council. Copies may be obtained from the Utility's Customer Service Office.

(q) Net metering.

(1) Net metering service is available to a customer-generator producing electric energy exclusively with a qualifying facility using a qualifying renewable technology when the generating capacity of the customer-generator's qualifying facility meets the following two (2) criteria:

a. The qualifying facility is sized to supply no more than one hundred twenty (120) percent of the customer-generator's average annual electricity consumption at that site, including all contiguous property owned or leased by the customer-generator, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way or utility rights-of-way; and

b. The rated capacity of the qualifying facility does not exceed the customer-generator's service entrance capacity.

(2) The energy generated by an on-site qualifying facility and delivered to the utility's electric distribution facility shall be used to offset energy provided by the utility to the customer-generator during the applicable billing period.

(3) The customer-generator and electric service arrangements shall be subject to the requirements and conditions described in the City of Fort Collins Utility Services Interconnection Standards for Generating Facilities Connected to the Fort Collins Distribution System.

(4) A customer-generator who receives approval from the electric utility to obtain net metering service shall be subject to the monthly rates described above in this rate schedule section.

(5) The customer-generator's consumption of energy from the utility shall be measured on a monthly basis and, in the event that the qualifying facility has produced more electricity than the customer-generator has consumed, the customer-generator shall receive a monthly credit for such production. During the second calendar quarter of each year, the customer-generator shall receive payment for the net excess generation accrued for the preceding twelve (12) months. The credit per kilowatt hour for the energy delivered to the electric utility under this provision shall be provided at the summer season energy charge as specified in Subsection (c) of this Section.

(r) Net metering – community solar projects.

(1) Net metering service is available to a customer who holds an exclusive interest in a portion of the electric energy generated by a community solar project when the generating capacity of the customer's interest is sized to supply no more than one hundred twenty (120) percent of the customer's average annual electricity consumption at the customer's point of service, including all contiguous property owned or leased by the customer, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way or utility rights-of-way.

(2) The community solar project-generator and electric service arrangements shall be subject to the requirements and conditions described in the City of Fort Collins Utility Services Interconnection Standards for Generating Facilities Connected to the Fort Collins Distribution System.

(3) Both the customer's consumption of energy from Fort Collins Utilities and interest in the production of energy that flows into Fort Collins Utilities' distribution system shall be measured on a monthly basis. The energy consumed from Fort Collins Utilities by the customer shall be billed at the applicable seasonal tiered rate as outlined in Subsection (c) of this Section. The energy produced by the customer's portion of the qualifying facility shall be credited to the customer as follows:

a. Distribution facilities charge, per kilowatt hour: one and fourteen one-hundredths cents ($0.0114).

b. The energy and demand credit, per kilowatt hour: four and sixteen one-hundredths cents ($0.0416).

(Code 1972, § 112-118(D); Ord. No. 137, 1988, § 4.A—C, 10-18-88; Ord. No. 131, 1989, § 2, 10-17-89; Ord. No. 109, 1992, § 4, 11-17-92; Ord. No. 129, 1995, § 4, 11-7-95; Ord. No. 133, 1996, § 1, 11-5-96; Ord. No. 211, 1998, § 15, 12-1-98; Ord. No. 59, 1999, §§ 1, 2, 5-4-99; Ord. No. 168, 1999, § 4, 11-16-99; Ord. No. 153, 2000, § 3, 11-7-00; Ord. No. 130, 2002, §§ 33, 35, 9-17-02; Ord. No. 154, 2003, § 3, 11-18-03; Ord. No. 173, 2004, § 4, 11-16-04; Ord. No. 140, 2006, § 3, 10-3-06; Ord. No. 122, 2007, § 3, 11-20-07; Ord. No. 112, 2008, § 3, 10-21-08; Ord. 056, 2009, § 3, 6-2-09; Ord. No. 115, 2009, § 3, 11-3-09; Ord. 003, 2010, § 7, 2-2-10; Ord. No. 114, 2010, § 3, 11-16-10; Ord. No. 079, 2011, §5, 9-6-11; Ord. No. 080, 2011, § 1, 9-6-11; Ord. No. 142, 2011, §§ 5, 6, 11-1-11; Ord. No. 114, 2012, § 3, 11-6-12; Ord. No. 146, 2013, § 3, 11-5-13; Ord. No. 108, 2014, § 5, 9-2-14; Ord. No. 154, 2014, § 3, 11-18-14)

Sec. 26-467. General service 25, schedule GS25.

(a) Availability. The schedule GS shall be available within the corporate limits of the City and the suburban fringe.

(b) Applicability. This schedule applies to individual commercial and industrial services, served at the established secondary voltage of the City's distribution system; and optionally, for apartments and multiple dwellings in existence prior to January 1, 1980, where more than one (1) dwelling or single living quarters are served through one (1) meter. Single-phase motors from one (1) to five (5) horsepower may be connected with the approval of the utility. This schedule applies to an individual single or three-phase service with an average metered demand of not less than twenty-five (25) kilowatts or greater than fifty (50) kilowatts.

(c) Monthly rate. The monthly rates for this schedule are as follows:

(1) Fixed charge, per account:

a. Single-phase, two-hundred-ampere service: three dollars and twenty-six cents ($3.26).

b. Single-phase, above two-hundred-ampere service: nine dollars and sixty cents ($9.60).

c. Three-phase, two-hundred-ampere service: four dollars and ninety-six cents ($4.96).

d. Three-phase, above two-hundred-ampere service: eleven dollars and seventy-four cents ($11.74).

(2) Demand charge, per kilowatt:

a. During the summer season billing months of June, July and August: seven dollars and fifty-two cents ($7.52).

b. During the non-summer season billing months of January through May and September through December: four dollars and thirty-seven cents ($4.37).

c. The meter reading date shall generally determine the summer season billing months; however, no customer shall be billed more than three (3) full billing cycles at the summer rate.

(3) Distribution facilities charge, per kilowatt hour: one and seventy-six one-hundredths cents ($0.0176).

(4) Energy charge, per kilowatt hour:

a. During the summer season billing months of June, July and August: four and sixteen one-hundredths cents ($0.0416).

b. During the non-summer season billing months of January through May and September through December: four and zero one-hundredths cents ($0.0400).

c. The meter reading date shall generally determine the summer season billing months; however, no customer shall be billed more than three (3) full billing cycles at the summer rate.

(5) In lieu of taxes and franchise: a charge at the rate of six and zero-tenths (6.0) percent of all monthly service charges billed pursuant to this Section.

(d) Renewable resource. Renewable energy resources, including, but not limited to, energy generated by the power of wind, may be offered on a voluntary basis to customers at a premium of two and four-tenths cents ($0.024) per kilowatt hour. The utility may establish and offer voluntary programs designed to increase and enhance the use of energy generated by renewable energy resources in support of Council-adopted policy applicable to the utility.

(e) Excess capacity charge. A monthly capacity charge of two dollars ($2.) per kilowatt may be added to the above charges for service to intermittent loads in accordance with the provisions of the electric service rules and regulations.

(f) Standby service charges. Standby service, if available, will be provided on an annual contract basis at a level at least sufficient to meet probable service demand (in kilowatts) as determined by the customer and approved by the utility according to the following:

(1) The monthly standby distribution charge shall be three dollars and eighty-two cents ($3.82) per kilowatt of contracted standby service. This charge shall be in lieu of the distribution facilities charge. For all metered kilowatts in excess of the contracted amount, the standby distribution charge shall be eleven dollars and forty-five cents ($11.45) per kilowatt.

(2) In the event the contractual kilowatt amount is exceeded, the beginning date of the contract period will be reset. The first month of the new contract period will become the current billing month and such month's metered demand shall become the minimum allowable contract demand for the standby service. Requests for standby service may be subject to a waiting period. An operation and maintenance charge may be added for special facilities required to provide standby service.

(g) Service charge. Service charges and connection fees shall be as set forth in Subsection 26-712(b) of this Chapter.

(h) Conservation assistance, rebates and incentives. The utility may establish programs to assist customers or provide incentives to customers in order to reduce energy consumption or system peak demands consistent with Council-adopted policy applicable to the utility. Such programs may include financial or technical assistance, incentives or rebates and shall be consistent with program objectives approved by the Utilities Executive Director.

(i) Billing demand. The billing demand shall be determined for each point of delivery by suitable meter measurement of the highest fifteen-minute integrated demand occurring during the billing period.

(j) Power factor. Power factor shall be determined by using watt and volt-ampere measurements collected by the electric meter at the point of service. The power factor calculated from such measurements shall be the basis of billing adjustment until satisfactory correction has been made. Review shall be conducted on a monthly basis by the utility. If the power factor falls below ninety-percent lagging, a power factor adjustment may be made by increasing the billing demand by one (1) percent for each one (1) percent or fraction thereof by which the power factor is less than ninety-percent lagging. This adjustment shall be based on the power factor at the time of maximum demand as recorded during the billing period.

(k) Service rights fee in certain annexed areas. A fee for defraying the cost of acquisition of service rights from Poudre Valley Rural Electric Association (PVREA) shall be charged for each service in areas annexed into the City after April 22, 1989, if such area was previously served by PVREA. The service rights will be collected monthly for a period of ten (10) consecutive years following the date of acquisition by the City of electric facilities in such area from PVREA. If service was previously provided by PVREA, the fee shall be twenty-five (25) percent of charges for electric power service. For services that come into existence in the affected area after date of acquisition, the fee shall be five (5) percent of charges for electric power service. In the event that the City Council has determined that a reduction of the service rights fee is justified in order to mitigate the economic impacts to a lot or parcel of land at the time of annexation of said lot or parcel of land, the service rights fee charged pursuant to this Subsection may be reduced by the City Council pursuant to a schedule set forth in the ordinance annexing said parcel or lot. The service rights fee charged pursuant to this Subsection shall not be subject to a charge in lieu of taxes and franchise otherwise required in this Section.

(l) Special services. Special services or complex service arrangements that are beyond those required for service under this rate schedule may be arranged by a written services agreement that the Utilities Executive Director may negotiate and enter into on behalf of the utility. Said agreement shall establish the terms and conditions for any special services or arrangements and shall incorporate by reference the requirements of this Chapter, as applicable. Any special services agreement modifying the rates, fees or charges for said services from those set forth in this Article shall be subject to approval by the City Council in accordance with Section 6 of Article XII of the Charter.

(m) Parallel generation. Customers may operate all or part of their instantaneous energy or capacity needs by operation of a qualifying facility in parallel with the utility system, provided that electric service is being rendered under the special services provisions of this schedule, and provided further that such facility is constructed, operated and maintained in accordance with the provisions of the electric service rules and regulations. The credit for the energy delivered to the electric utility under this provision shall be provided at applicable Platte River Power Authority avoided cost rates. If a customer is receiving net metering service, such customer's service shall also be governed by the net metering service terms and conditions described in Subsection (r) below, and the credit for energy delivered to the electric utility shall be calculated as described in the Subsection.

(n) Commodity delivery. If the electric utility authorizes the delivery of electric capacity or energy utilizing the utility's distribution system under mandatory provisions of state or federal law, a credit will be applied to the customer's monthly electric bill based upon the electric utility's displaced costs as credited to the utility by its supplier of electric energy. Capacity, energy, standby capacity, backup capacity and special services shall be delivered, metered, billed, dispatched and controlled in accordance with a special services agreement with the electric utility.

(o) Payment of charges. Due dates and delinquency procedures shall be as set forth in § 26-713.

(p) Contract period. The applicant shall take electric service under this or any other applicable schedule which is in effect during the term of the contract subject to adjustment from time to time by the City Council. All contracts under this schedule shall be for twelve (12) months and shall be automatically renewed annually. The contract may be terminated at the end of the term upon the giving of ten (10) days' advance written notice to the City or may be terminated upon the giving of ten (10) days' advance written notice to the City in the event of vacation of the premises or a change in ownership or tenant occupancy status.

(q) Rules and regulations. Service supplied under this schedule is subject to the terms and conditions set forth in the electric utility rules and regulations as approved by the City Council. Copies may be obtained from the Utility's Customer Service Office.

(r) Net metering.

(1) Net metering service is available to a customer-generator producing electric energy exclusively with a qualifying facility when the generating capacity of the customer-generator's qualifying facility meets the following two (2) criteria:

a. The qualifying facility is sized to supply no more than one hundred twenty (120) percent of the customer-generator's average annual electricity consumption at that site, including all contiguous property owned or leased by the customer-generator, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way or utility rights-of-way; and

b. The rated capacity of the qualifying facility does not exceed the customer-generator's service entrance capacity.

(2) The energy generated by an on-site qualifying facility and delivered to the utility's electric distribution facility shall be used to offset energy provided by the utility to the customer-generator during the applicable billing period.

(3) The customer-generator and electric service arrangements shall be subject to the requirements and conditions described in the City of Fort Collins Utility Services Interconnection Standards for Generating Facilities Connected to the Fort Collins Distribution System.

(4) A customer-generator who receives approval from the electric utility to obtain net metering service shall be subject to the monthly rates described above in this rate schedule section.

(5) The customer-generator's consumption of energy from the utility shall be measured on a monthly basis and, in the event that the qualifying facility has produced more electricity than the customer-generator has consumed, the customer-generator shall receive a monthly credit for such production. During the second calendar quarter of each year, the customer-generator shall receive payment for the net excess generation accrued for the preceding twelve (12) months. The credit per kilowatt hour for

the energy delivered to the electric utility under this provision shall be provided at the summer season energy charge as specified in Subsection (c) of this Section.

(Ord. No. 142, 2011, § 7, 11-1-11; Ord. No. 114, 2012, § 4, 11-6-12; Ord. No. 146, 2013, § 4, 11-5-13; Ord. No. 154, 2014, § 4, 11-18-14)

Sec. 26-468. General service 50, schedule GS50.

(a) Availability. The general service 50, schedule GS50 shall be available within the corporate limits of the City and the suburban fringe.

(b) Applicability. This schedule applies to customers served at the established secondary voltage of the City's distribution system. This schedule applies only to individual services with an average metered demand not less than fifty (50) kilowatts and not greater than seven hundred fifty (750) kilowatts.

(c) Monthly rate. The monthly rates for this schedule are as follows:

(1) Fixed charge, per account: nine dollars and forty-five cents ($9.45). An additional charge of forty dollars and zero cents ($40.) may be assessed if telephone communication service is not provided by the customer.

(2) Coincident demand charge, per kilowatt:

a. During the summer season billing months of June, July and August: eleven dollars and eighteen cents ($11.18).

b. During the non-summer season billing months of January through May and September through December: seven dollars and eighty cents ($7.80).

c. The meter reading date shall generally determine the summer season billing months; however, no customer shall be billed more than three (3) full billing cycles at the summer rate.

(3) Distribution facilities demand charge, per kilowatt: five dollars and ninety cents ($5.90).

(4) Energy charge, per kilowatt hour:

a. During the summer season billing months of June, July and August: four and sixteen one-hundredths cents ($0.0416).

b. During the non-summer season billing months of January through May and September through December: four and zero one-hundredths cents ($0.0400).

c. The meter reading date shall generally determine the summer season billing months; however, no customer shall be billed more than three (3) full billing cycles at the summer rate.

(5) In lieu of taxes and franchise: a charge at the rate of six and zero-tenths (6.0) percent of all monthly service charges billed pursuant to this Section.

(d) Renewable resource. Renewable energy resources, including, but not limited to, energy generated by the power of wind, may be offered on a voluntary basis to customers at a premium of two and four-tenths cents ($0.024) per kilowatt hour. The utility may establish and offer voluntary programs designed to increase and enhance the use of energy generated by renewable energy resources in support of Council-adopted policy applicable to the utility.

(e) Excess capacity charge. A monthly capacity charge of two dollars ($2.) per kilowatt may be added to the above charges for service to intermittent loads in accordance with the provisions of the electric service rules and regulations.

(f) Standby service charges. Standby service, if available, will be provided on an annual contract basis at a level at least sufficient to meet probable service demand (in kilowatts) as determined by the customer and approved by the utility according to the following:

(1) Standby distribution charge.

a. The monthly standby distribution charge shall be four dollars and seventy-two cents ($4.72) per kilowatt of contracted standby service. This charge shall be in lieu of the distribution facilities charge. For all metered kilowatts in excess of the contracted amount, the standby distribution charge shall be fourteen dollars and sixteen cents ($14.16) per kilowatt.

b. In the event the contractual kilowatt amount is exceeded, the beginning date of the contract period will be reset. The first month of the new contract period will become the current billing month and such month's metered demand shall become the minimum allowable contract demand for the standby service. Requests for standby service may be subject to a waiting period. An operation and maintenance charge may be added for special facilities required to provide standby service.

(2) Standby generation and transmission charge. All charges incurred by the utility under Platte River Power Authority's applicable tariffs, as may be amended from time to time, will be billed to the customer as a standby generation and transmission charge.

(g) Excess circuit charge. In the event a utility customer in this rate class desires excess circuit capacity for the purpose of controlling the available electric capacity of a backup circuit connection, this service, if available, will be provided on an annual contract basis at a level at least sufficient to meet probable backup demand (in kilowatts) as determined by the customer and approved by the utility according to the following:

(1) The excess circuit charge shall be eighty-six cents ($0.86) per contracted kilowatt of backup capacity per month. For any metered kilowatts in excess of the contracted amount, the excess circuit charge shall be two dollars and fifty-eight cents ($2.58) per kilowatt.

(2) In the event the contractual kilowatt limit is exceeded, a new annual contract period will automatically begin as of the month the limit is exceeded. The metered demand in the month of exceedance shall become the minimum contracted demand level for the excess circuit charge.

(h) Service charge. Service charges and connection fees shall be as set forth in Subsection 26-712(b).

(i) Conservation assistance, rebates and incentives. The utility may establish programs to assist customers or provide incentives to customers in order to reduce energy consumption or system peak demands consistent with Council-adopted policy applicable to the utility. Such programs may include financial or technical assistance, incentives or rebates and shall be consistent with program objectives approved by the Utilities Executive Director.

(j) Coincident demand. The coincident demand for any month shall be the customer's sixty-minute integrated kilowatt demand recorded at the hour coincident with the monthly system peak demand for Platte River Power Authority. The monthly system peak demand for Platte River Power Authority shall be the maximum coincident sum of the measured demands for the participating municipalities recorded during the billing month.

(k) Distribution facilities demand. The distribution facility demand charge used by the utility is designed to recover the costs of operating and maintaining the electric distribution system, including customer service and administrative functions, and it is based on a per unit rate tied to the peak demand (kW) of a customer's monthly electric use. Under the utility's billing system, cost recovery is based on a twelve-month model. Monthly billing is one-twelfth (1/12) of the annual cost recovery required for given service and the twelve-month use patterns serve as the reference base for monthly billings.

(1) The distribution facilities demand shall be determined for each point of delivery by suitable meter measurement of the highest one-hour integrated demand occurring during the billing period and shall not be less than seventy (70) percent of the highest distribution facilities demand (in kilowatts) occurring in any of the preceding eleven (11) months.

(2) If the Utilities Executive Director determines that the calculation described in Paragraph (1) above does not recover the customer's share of the actual distribution facilities costs, the customer's distribution facilities demand charge may be determined according to a billing calendar designed to fully recover said customer's share of the distribution facilities costs.

(l) Power factor adjustment. Power factor shall be determined by using watt and volt-ampere reactive measurements collected by the electric meter at the point of service. The power factor calculated from such measurements shall be the basis of billing adjustment until satisfactory correction has been made. Review shall be conducted on a monthly basis by the utility. If the power factor falls below ninety-percent lagging, a power factor adjustment may be made by increasing the coincident and distribution facilities demand by one (1) percent for each one (1) percent or fraction thereof by which the power factor is less than ninety-percent lagging. This adjustment shall be based on the power factor at the time of maximum demand as recorded during the billing period.

(m) Primary service. When service is metered under this schedule at primary voltage, a discount shall be made each month of one and one-half (1½) percent of the bill for service. Where service is taken at the City's established primary voltage and the City does not own the transformers and substations converting to secondary voltage, an additional credit of two (2) percent of the monthly bill shall be allowed.

(n) Service rights fee in certain annexed areas. A fee for defraying the cost of acquisition of service rights from Poudre Valley Rural Electric Association (PVREA) shall be charged for each service in areas annexed into the City after April 22, 1989, if such area was previously served by PVREA. The service rights fee will be collected monthly for a period of ten (10) consecutive years following the date of acquisition by the City of electric facilities in such area from PVREA. If service was previously provided by PVREA, the fee shall be twenty-five (25) percent of charges for electric power service. For services that come into existence in the affected area after date of acquisition, the fee shall be five (5) percent of charges for electric power service. In the event that the City Council has determined that a reduction of the service rights fee is justified in order to mitigate the economic impacts to a lot or parcel of land at the time of annexation of said lot or parcel of land, the service rights fee charged pursuant to this Subsection may be reduced by the City Council pursuant to a schedule set forth in the ordinance annexing said parcel or lot. The service rights fee charged pursuant to this Subsection shall not be subject to the charge in lieu of taxes and franchise otherwise required in this Subsection.

(o) Special services. Special services or complex service arrangements that are beyond those required for service under this rate schedule may be arranged by a written services agreement that the Utilities Executive Director may negotiate and enter into on behalf of the utility. Said agreement shall establish the terms and conditions for any special services or arrangements and shall incorporate by reference the requirements of this Chapter, as applicable. Any special services agreement modifying the rates, fees or charges for said services from those set forth in this Article shall be subject to approval by the City Council in accordance with Section 6 of Article XII of the Charter.

(p) Parallel generation. Customers may operate all or part of their instantaneous energy or capacity needs by operation of a qualifying facility in parallel with the utility system, provided that electric service is being rendered under the special services provisions of this schedule, and provided further that such facility is constructed, operated and maintained in accordance with the provisions of the electric service rules and regulations. The credit for the energy delivered to the electric utility under this provision shall be provided at applicable Platte River Power Authority avoided cost rates. Parallel generation will be provided consistent with all of the requirements contained in Platte River Power Authority's Tariff Schedule 3: Parallel Generation Purchases, as may be amended from time to time. All charges incurred by the utility under this tariff will be billed to the customer. If a customer is receiving net metering service, such customer's service shall also be governed by the net metering service terms and conditions described in Subsection (u) below, and the credit for energy delivered to the electric utility shall be calculated as described in that Subsection.

(q) Commodity delivery. If the electric utility authorizes the delivery of electric capacity or energy utilizing the utility's distribution system under mandatory provisions of state or federal law, a credit will be applied to the customer's monthly electric bill based upon the electric utility's displaced costs as credited to the utility by its supplier of electric energy. Capacity, energy, standby capacity, backup capacity and special services shall be delivered, metered, billed, dispatched and controlled in accordance with a special services agreement with the electric utility.

(r) Payment of charges. Due dates and delinquency procedures shall be as set forth in § 26-713.

(s) Contract period. The applicant shall take electric service under this or any other applicable schedule which is in effect during the term of the contract, subject to adjustment from time to time by the City Council. All contracts under this schedule shall be for twelve (12) months and shall be automatically renewed annually. The contract may be terminated at the end of the term upon the giving of thirty (30) days' advance written notice to the City or may be terminated upon the giving of thirty (30) days' advance written notice to the City in the event of vacation of the premises or a change in ownership or tenant occupancy status.

(t) Rules and regulations. Service supplied under this schedule is subject to the terms and conditions set forth in the electric utility rules and regulations as approved by the City Council. Copies may be obtained from the Utility's Customer Service Office.

(u) Net metering.

(1) Net metering service is available to a customer-generator producing electric energy exclusively with a qualifying facility using a qualifying renewable technology when the generating capacity of the customer-generator's qualifying facility meets the following two (2) criteria:

a. the qualifying facility is sized to supply no more than one hundred twenty (120) percent of the customer-generator's average annual electricity consumption at that site, including all contiguous property owned or leased by the customer-generator, without regard to interruptions in contiguity caused by easements, public thoroughfares, transportation rights-of-way or utility rights-of-way; and

b. the rated capacity of the qualifying facility does not exceed the customer-generator's service entrance capacity.

(2) The energy generated by an on-site qualifying facility and delivered to the utility's electric distribution facility shall be used to offset energy provided by the utility to the customer-generator during the applicable billing period.

(3) The customer-generator and electric service arrangements shall be subject to the requirements and conditions described in the City of Fort Collins Utility Services Interconnection Standards for Generating Facilities Connected to the Fort Collins Distribution System.

(4) A customer-generator who receives approval from the electric utility to obtain net metering service shall be subject to the monthly rates described above in this rate schedule section.

(5) The customer-generator's consumption of energy from the utility shall be measured on a monthly basis and, in the event that the qualifying facility has produced more electricity than the customer-generator has consumed, the customer-generator shall receive a monthly credit for such production. During the second calendar quarter of each year, the customer-generator shall receive payment for the net excess generation accrued for the preceding twelve (12) months. The credit per kilowatt hour for the energy delivered to the electric utility under this provision shall be provided at the summer season energy charge as specified in Subsection (c) of this Section.

(Code 1972, § 112-118(F); Ord. No. 137, 1988, § 6.A—E, 10-18-88; Ord. No. 131, 1989, § 4, 10-17-89; Ord. No. 109, 1992, § 6, 11-17-92; Ord. No. 129, 1995, § 6, 11-7-95; Ord. No. 133, 1996, § 1, 11-5-96; Ord. No. 211, 1998, § 17, 12-1-98; Ord. No. 59, 1999, §§ 1, 2, 5-4-99; Ord. No. 168, 1999, § 6, 11-16-99; Ord. No. 153, 2000, § 4, 11-7-00; Ord. No. 130, 2002, §§ 33, 35, 9-17-02; Ord. No. 154, 2003, § 4, 11-18-03; Ord. No. 173, 2004, § 5, 11-16-04; Ord. No. 140, 2006, § 4, 10-3-06; Ord. No. 122, 2007, § 4, 11-20-07; Ord. No. 112, 2008, § 4, 10-21-08; Ord. 056, 2009, § 4, 6-2-09; Ord. No. 077, 2009, §§ 1, 2, 7-21-09; Ord. No. 115, 2009, § 4, 11-3-09; Ord. No. 003, 2010, § 8, 2-2-10; Ord. No. 114, 2010, § 4, 11-16-10; Ord. No. 079, 2011, § 6, 9-6-11; Ord. No. 080, 2011, § 1, 9-6-11; Ord. No. 142, 2011, §§ 7, 8, 11-1-11; Ord. No. 114, 2012, § 5, 11-6-12; Ord. No. 146, 2013, § 5, 11-5-13; Ord. No. 154, 2014, § 5, 11-18-14)

Effective upon enactment $6.81
Effective July 1, 2008 $7.49
Effective July 1, 2009 $8.17

e. Selection of Rates

A customer may receive service under any of the General Service Rate Schedules, if desired, but will be ineligible for both the Lifeline Service Credit and the Low-Income Credit as set forth in Sections 4.c. and 4.d., above, and still obliged to provide Rates R-1(D) and R-1(E) to eligible Sub-metered units.

f. Posting Rates

The owner shall post, in a conspicuous place, the prevailing residential electric rate schedule published by the Department, which would be applicable to the tenants if they were individually served by the Department.

g. Tenant Billing

The owner shall provide separate written electricity bills for each tenant, including the opening and closing meter readings for each billing period, the date the meters were read, the total electricity metered for the billing period, and the amount of the bill.

SCHEDULE A-1
SMALL GENERAL SERVICE
Rate Effective July 1, 2009

1. Applicability

Applicable to General Service below 30 kW demand, the highest demand recorded in the last twelve months, including lighting and power, charging of batteries of commercial electric vehicles, which may be delivered through the same service in compliance with the Department's Rules, and to single-family residential service with an on-site transformer dedicated solely to that individual customer. Not applicable to service which parallels, and connects to, customer’s own generating facilities, except as such facilities are intended solely for emergency standby.

2. Monthly Rates

	High Season June - Sep.	Low Season Oct. - May
a. Rate A		
1 Service Charge	$ 6.50	$ 6.50
2 Facilities Charge - per kW	$ 5.00	$ 5.00

3	Energy Charge - per kWh	$ 0.06558	$ 0.04268
4	ECA - per kWh	See General Provisions	
5	ESA - per kW	See General Provisions	
6	RCA - per kW	See General Provisions	

b. Rate B - Time-of-Use

1	Service Charge	$ 15.00	$ 15.00
2	Facilities Charge - per kW	$ 5.00	$ 5.00
3	Energy Charge - per kWh		
	High Peak Period	$ 0.16385	$ 0.05854
	Low Peak Period	$ 0.10256	$ 0.05854
	Base Period	$ 0.03122	$ 0.03122
4	Electric Vehicle Discount - per kWh	$(0.02500)	$(0.02500)
5	ECA - per kWh	See General Provisions	
6	ESA - per kW	See General Provisions	
7	RCA - per kW	See General Provisions	

3. Billing

The bill under Rate A shall be the sum of parts (1) through (6). The bill under Rate B shall be the sum of parts (1) through (7).

4. General Conditions

a. Facilities Charge

The Facilities Charge shall be based on the highest demand recorded in the last 12 months, but not less than 4 kW.

b. Selection of Rates

(1) The Department requires mandatory service under Rate B for single-family residential service with an on-site transformer dedicated solely to that individual customer.

(2) If a customer is not a single-family residential service with an on-site transformer dedicated solely to that individual customer in accordance with conditions as set forth in Section 4.b.(1), above, a customer may choose to receive service either under Rate A or B. However, when a customer served under Rate B requests a change to Rate A, that customer may not revert to Rate B before 12 months have elapsed.

(3) The customer shall be placed on Schedule A-2 or A-3 whose Maximum Demand either:

- Reaches or exceeds 30 kW in any three billing months or two bimonthly billing periods during the preceding 12 month period

- Reaches or exceeds 30 kW during two High Season billing months or one High Season bimonthly billing period within a calendar year

c. **Electric Vehicle Discount**

Owners of licensed passenger or commercial electric vehicles shall be entitled to a discount on the block of energy designated by the Department as necessary for basic vehicle charging. Proof of vehicle registration and charging location is required.

SCHEDULE A-2
PRIMARY SERVICE
Rate Effective July 1, 2009

1. **Applicability**

Applicable to General Service delivered from the Department's 4.8kV system and 30kW demand or greater, the highest demand recorded in the last twelve months, including lighting and power, charging of batteries of commercial electric vehicles, which may be delivered through the same service in compliance with the Department's Rules, and to single-family residential service with an on-site transformer dedicated solely to that individual customer. Not applicable to service which parallels, and connects to, the customer's own generating facilities, except as such facilities are intended solely for emergency standby.

2. **Monthly Rates**

		High Season June - Sep.	Low Season Oct. - May
a.	**Rate A - Standard Service**		
1	Service Charge	$ 25.00	$ 25.00
2	Facilities Charge - per kW	$ 5.00	$ 5.00
3	Demand Charge - per kW	$ 9.00	$ 5.50
4	Energy Charge - per kWh	$ 0.03645	$ 0.02995
5	ECA - per kWh	See General Provisions	
6	ESA - per kW	See General Provisions	
7	RCA - per kW	See General Provisions	
b.	**Rate B - Time-of-Use**		
1	Service Charge	$ 28.00	$ 28.00
2	Facilities Charge - per kW	$ 5.00	$ 5.00
3	Demand Charge - per kW		
	High Peak Period	$ 9.00	$ 4.25

	Low Peak Period	$ 3.25	$ -
	Base Period	$ -	$ -
4	Energy Charge - per kWh		
	High Peak Period	$ 0.04679	$ 0.04045
	Low Peak Period	$ 0.03952	$ 0.04045
	Base Period	$ 0.01879	$ 0.02252
5	Electric Vehicle Discount - per kWh	$(0.02500)	$ 0.02500)
6	ECA - per kWh	See General Provisions	
7	ESA - per kW	See General Provisions	
8	RCA - per kW	See General Provisions	
9	Reactive Energy Charge (Applied if demand as determined for the Facilities Charge is greater than 250 kW)		
	a. Unmetered - per kWh		
	High Peak Period	$ 0.00026	$ 0.00023
	Low Peak Period	$ 0.00017	$ 0.00023
	Base Period	$ 0.00011	$ 0.00014

b. Metered - per kvarh per Power Factor level below

	High Season - (June - Sep)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$0.00088	$0.00059	$0.00036
0.900-0.949	$0.00167	$0.00113	$0.00058
0.800-0.899	$0.00509	$0.00339	$0.00153
0.700-0.799	$0.00853	$0.00571	$0.00254
0.600-0.699	$0.01185	$0.00787	$0.00351
0.000-0.599	$0.01293	$0.00859	$0.00383

	Low Season - (Oct - May)		
Power Factor Range	High Peak	Low Peak	Base
0.995-1.000	$ -	$ -	$ -
0.950-0.994	$0.00076	$0.00076	$0.00043
0.900-0.949	$0.00145	$0.00145	$0.00070
0.800-0.899	$0.00439	$0.00439	$0.00183
0.700-0.799	$0.00737	$0.00737	$0.00305
0.600-0.699	$0.01023	$0.01023	$0.00421
0.000-0.599	$0.01116	$0.01116	$0.00460

3. Billing

The bill under Rate A shall be the sum of parts (1) through (7). The bill under Rate B shall be the sum of parts (1) through (9).

4. General Conditions

a. Demand Charge

The Demand Charge under Rate A-2(A) shall be based on the Maximum Demand recorded at any time during the billing month. The Demand Charge under Rate A-2(B) shall be based on the Maximum Demands recorded within the applicable Rating Periods during the billing month.

b. Facilities Charge

The Facilities Charge shall be based on the highest demand recorded in the last 12 months, but not less than 30 kW.

c. Selection of Rates

(1) The Department requires mandatory service under Rate B for customers whose Maximum Demand reach or exceed the demand levels below in any three billing months during the preceding 12 month period, or whose Maximum Demand reach or exceed the demand levels below during two High Season billing months within a calendar year:

- 75 kW effective January 1, 2009
- 50 kW effective January 1, 2010
- 30 kW effective January 1, 2011

(2) If a customer's monthly Maximum Demand does not reach or exceed the demand levels in accordance with conditions as set forth in Section 4.c.(1), above, a customer may choose to receive service either under Rate A or B. However, when a customer served under Rate A requests a change to Rate B, that customer may not revert to Rate A before 12 months have elapsed.

(3) Customers shall be placed on the applicable rate under Schedule A-1 if demand, as determined for the Facilities Charge, drops below 30 kW. Rate A-2(A) shall expire on December 31, 2011.

d. Electric Vehicle Discount

Owners of licensed passenger or commercial electric vehicles shall be entitled to a discount on the block of energy designated by the Department as necessary for basic vehicle charging. Proof of vehicle registration and charging location is required.

e. Reactive Energy Charge

Reference Schedule A-3, Section 4.a.

Delivery Charge **[This rate shall become effective December 1, 2014]**: $0.02712 per KWH

Base Power Cost: The per kWh base power costs for Power Supply Charges stated in the Power Cost Recovery (PCR) Tariff

Power Cost Adjustment: The charge per kWh for changes in Power Supply Charges relative to the base power cost and calculated in accordance with the Power Cost Recovery (PCR) Tariff

The monthly bill shall be the sum of the above charges plus any applicable fees.

100.2 Water Well (W)

Applicability - Applicable to water wells used solely for small scale agricultural purposes. Agricultural purposes include livestock watering, crop irrigation, and fisheries. Irrigation for recreational purposes is served under other Tariffs.

Rates

Service Availability Charge: $19.50 per month

Delivery Charge **[This rate shall become effective December 1, 2014]**: $0.02712 per KWH

Base Power Cost: The per kWh base power costs for Power Supply Charges stated in the Power Cost Recovery (PCR) Tariff

Power Cost Adjustment: The charge per kWh for changes in Power Supply Charges relative to the base power cost and calculated in accordance with the Power Cost Recovery (PCR) Tariff

The monthly bill shall be the sum of the above charges plus any applicable fees.

100.3 Small Power (SP)

Applicability - Applicable to all commercial and industrial members whose rolling 12-month average demand is less than 75 kilowatts and whose use is not covered by another specific rate schedule. Member owned street lighting will also be billed under the Small Power Rate.

Rates

Service Availability Charge: $37.50 per month

Delivery Charge **[This rate shall become effective December 1, 2014]**: $0.02101 per KWH

Base Power Cost: The per kWh base power costs for Power Supply Charges stated in the Power Cost Recovery (PCR) Tariff

Power Cost Adjustment: The charge per kWh for changes in Power Supply Charges relative to the base power cost and calculated in accordance with the Power Cost Recovery (PCR) Tariff

The monthly bill shall be the sum of the above charges plus any applicable fees.

100.4 Large Power (LP)

Applicability - Applicable to all commercial and industrial members whose rolling 12-month average demand is 75 kilowatts but less than 10,000 kilowatts, and whose use is not covered by another specific rate schedule.

Rates

Service Availability Charge: $150.00 per month

Electricity Facts Label
Reliant Energy Retail Services, LLC
Reliant Rockets Secure Advantage 12 plan
CenterPoint Energy service area
Issue Date: 10/14/2014

Electricity price

Average monthly use:	500 kWh	1000 kWh	2000 kWh
Average price per kWh:	15.2¢	12.4¢	11.9¢

This price disclosure is based on the following components:

Usage Charge:	$9.95	per billing cycle < 800 kWh
	$0.00	per billing cycle ≥ 800 kWh
Energy Charge:	7.4¢	per kWh
CenterPoint Energy Delivery Charges:	$8.52 per month and 4.0981¢ per kWh	

CenterPoint Energy Delivery Charges include all recurring charges from CenterPoint Energy passed through without mark-up

This price disclosure is an example based on average prices - your average price for electricity service will vary according to your usage. The price you pay each month will consist of the Usage Charge, Energy Charge, and CenterPoint Energy Delivery Charges. The Usage Charge will not be included for each billing cycle in which your usage is 800 kilowatt hours (kWh) or more.

Other Key Terms and questions

See Terms of Service statement for full listing of fees, deposit policy, and other terms.

Disclosure Chart

Type of Product	Fixed Rate
Contract Term	12 months
Do I have a termination fee or any fees associated with terminating service?	Yes. $150. Applies through the end of the contract term. This fee does not apply if the customer moves, and provides a forwarding address and other evidence that may be requested to verify that the customer moved.
Can my price change during the contract period?	Yes
If my price can change, how will it change and by how much?	The price can change to reflect actual price changes that are allowed by Public Utility Commission rules due to changes in law or regulatory charges after the Issue Date.
What other fees may I be charged?	Fees not included in the price above: Disconnect Notice Fee: $10; Returned Payment Charge: $25; Disconnect Recovery: $25; Service Processing Fee: up to $5.95; Late Payment Penalty: 5% of past due balances; Information on other non-recurring fees is available in the pricing section of your Terms of Service.
Is this a pre-pay or pay in advance product?	No
Does Reliant purchase excess distributed renewable generation?	Yes
Renewable Content	This product is 6% renewable.
Statewide average for renewable content	The statewide average for renewable content is 11%.

Reliant, PO Box 3765, Houston, TX, 77253
reliant.com, e-mail: service@reliant.com, phone: 1-866-RELIANT, 24 hours a day / 7 days a week
PUCT Certificate Number #10007

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General Service
Rate Schedule GS

I. Applicability

This Rate Schedule 1-GS applies to single- or three-phase nonresidential general service delivered at standard voltages designated by SMUD as available at the customer's premise. This schedule is mandatory for all commercial and industrial (C&I) accounts with monthly maximum demand that does not exceed 299 kW for three or more consecutive months. This schedule also applies to General Service accounts with contract capacity of 299 kW or less. The demand for any month shall be the maximum 15-minute kW delivery during the month. For the purposes of this schedule a "month" is considered to be a single billing period of 27 to 34 days.

A. Small Nondemand Service (GSN_T)

This rate applies to General Service accounts with a monthly maximum demand of 20 kW or less. Whenever the monthly maximum demand exceeds 20 kW for *any* three consecutive months **and** the monthly energy usage is at least 7,300 kWh for *any* three consecutive months within a 12-month period, the account will be billed on the applicable demand rate. To return to the nondemand rate, the monthly maximum demand must be 20 kW or less for 12-consecutive months **or** the usage must be less than 7,300 kWh for 12 consecutive months.

B. Small Nondemand, Nonmetered Service (GFN)

This rate applies to General Service accounts where an account's monthly consumption of electricity is consistently small or can be predetermined with reasonable accuracy by reference to the capacity of equipment served and the hours of operation. SMUD, at its discretion, and with the customer's consent, will calculate electricity consumed in lieu of providing metering equipment. The calculated electricity consumption will be billed at the average of the GSN_T rate's annual electricity usage charges.

C. Small Demand Service (GSS_T)

This rate applies to General Service accounts with a monthly maximum demand of at least 21 kW but does not exceed 299 kW for *any* three consecutive months **and** monthly energy usage of at least 7,300 kWh for *any* three consecutive months within a 12-month period. The customer will be billed on this demand rate unless the monthly usage is less than 7,300 for 12 consecutive months; or the maximum demand falls below 21 kW for 12 consecutive months or the monthly maximum demand exceeds 299 kW for three consecutive months.

II. Firm Service Rates

Rate Category	Nondemand GSN_T	Flat GFN	Demand GSS_T
Winter Season - October 1 through May 31			
System Infrastructure Fixed Charge - per month per meter	$16.00	$8.45	$23.10
Site Infrastructure Charge *(per 12 months max kW or contract capacity)*	n/a	n/a	$7.14
Electricity Usage Charge			
All day $/kWh	$0.1266	$0.1278	$0.0962
Summer Season - June 1 through September 30			
System Infrastructure Fixed Charge - per month per meter	$16.00	$8.45	$23.10
Site Infrastructure Charge *(per 12 months max kW or contract capacity)*	n/a	n/a	$7.14
Electricity Usage Charge			
On-peak $/kWh	$0.2862	$0.1278	$0.2455
Off-peak $/kWh	$0.1075	$0.1278	$0.0852

III. Electricity Usage Surcharges

Refer to the following rate schedules for details on these surcharges:

A. **Solar Surcharge.** Refer to Rate Schedule 1-SB1.

B. **Hydro Generation Adjustment (HGA).** Refer to Rate Schedule 1-HGA.

IV. Rate Option Menu

A. Energy Assistance Program for Nonprofit Agencies. Refer to Rate Schedule 1-EAPR.

B. Campus Rates. Refer to Rate Schedule 1-CB.

C. Implementation of Energy Efficiency Program or Installation of New Solar/Photovoltaic Systems

Customers who implement a SMUD-sponsored Energy Efficiency program or who install a SMUD-approved solar/photovoltaic system to offset their on-site energy usage may request, in writing, within 30 days of the project completion and commissioning, an adjustment to their billing demand based on the anticipated reduction in kW from the Energy Efficiency Project Worksheet. The adjusted billing demand is valid for 12 months or until it is exceeded by actual maximum demand.

D. Generator Standby Service Option

Generator Standby Service applies when the following conditions are met:

1. The customer has generation, sited on the customer premise, that serves all or part of the customer's load; and
2. The generator(s) are not fueled by a renewable resource; and
3. The generator(s) are connected to SMUD's electrical system; and
4. SMUD is required to have resources available to provide supplemental service, backup electricity and/or to supply electricity during generator(s) maintenance service.

Generator Standby Service Charge by Voltage Level	Secondary	Primary	Subtransmission
($/kW of Contract Capacity per month)	$6.25	$4.95	$2.50

In addition to the Generator Standby Service Charge, SMUD will continue to bill for all applicable charges under this rate schedule, including, but not limited to, System Infrastructure Fixed Charges, Site Infrastructure Charges, and electricity usage charges for SMUD-provided power.

The Generator Standby Service Charge will be waived for qualifying net metered generation. Refer to Rate Schedule 1-NEM.

E. Net Energy Metering Option. Refer to Rate Schedule 1-NEM.

F. Green Pricing Options

1. **SMUD Community Solar Option**
   Under this premium service option, customers elect to contribute monthly payments toward the installation of a photoelectric system at a selected community locale. Refer to the SMUD website, www.smud.org, for further information on monthly contribution options and projects.

2. **SMUD Renewable Energy Option**
   Customers electing this premium power service will receive an additional charge for monthly energy of no less than 1/2 cent and no greater than 2 cents per kWh. SMUD may offer up to three premium rate options representing various blends of renewable resources and/or renewable energy credits within the 1/2 cent to 2 cent range. The actual prices will be published each November and will be based on the expected above market cost of renewable resources for the upcoming year. Participation will be limited to the amount of resources that SMUD is able to secure at or below the 2 cent premium limit.

G. Special Metering Charge

For customers who purchase and install additional equipment and software identified by SMUD meter specialists as necessary for load data collection and transfer to electronic media outside SMUD, SMUD will charge a monthly service fee to cover maintenance, software support and licensing fees. Payment for this nonstandard equipment and service will be made through provisions in Rule and Regulation 2, Section IV. Special Facilities. The fee schedule is available at SMUD's website, www.smud.org.

V. Conditions of Service

A. Type of Electric Service

SMUD will provide customers on this rate schedule standard, firm service consisting of a continuous and sufficient supply of electricity.

B. Service Voltage Definition

The following defines the three voltage classes available. The rate will be determined by the voltage level at which service is provided according to the following:

1. *Secondary Service Voltage*
   This service class provides power at voltage levels below 12 kilo-Volts (kV), or at a level not otherwise defined as "Primary" or "Subtransmission."

2. *Primary Service Voltage*
   This service class provides power at a voltage level of 12 kV or 21 kV. To be eligible for Primary Service Voltage, the customer's monthly demand must exceed 299 kW, the voltage must be available in the area being served, and SMUD must approve the arrangement for power provision.

3. *Subtransmission Service Voltage*
   This subtransmission service class provides power at a voltage level of 69 kV or as otherwise defined by SMUD. To be eligible for voltage service at this level, the customer's monthly demand must exceed 499 kW, the voltage must be available in the area being served, and SMUD must approve the arrangement for power provision.

C. Power Factor Adjustment or Waiver

1. **Adjustment (charge per month varies)**
   Accounts on a demand rate may be subject to a power factor (PF) adjustment charge. When a customer's monthly power factor falls below 95 percent leading or lagging, the following billing adjustment will apply:

   Electricity Usage x [(95% ÷ Power Factor) - 1] x Power Factor Adjustment Rate

   Electricity Usage: *the total monthly kWh for the account*

   Power Factor: *the lesser of the customer's monthly power factor or 95 percent*

   Power Factor Adjustment Rate per excess KVAR $0.0103

2. **Waiver Contract (charge per month is set for the term of the waiver)**
   Customers may apply for a power factor waiver contract that compensates SMUD for the power factor correction for the portion that is covered under the contract.
   The waiver amount per month is calculated:

   Excess KVAR x Waiver Rate

   Excess KVAR: Maximum 12-month KVAR in excess of 32.868 percent of kW

   Waiver Rate per excess KVAR $0.2719

D. Winter (October 1 – May 31) All hours are off-peak.

E. Summer Time-of-Use Billing Periods (June 1 – September 30)

On-Peak	Summer weekdays between 3:00 p.m. and 6:00 p.m.
Off-Peak	All other hours, including holidays shown below

Off-peak pricing shall apply during the following holidays:

Holiday	Month	Date
New Year's Day	January	1
Martin Luther King Jr. Day	January	Third Monday
Lincoln's Birthday	February	12
Presidents Day	February	Third Monday
Memorial Day	May	Last Monday
Independence Day	July	4
Labor Day	September	First Monday
Columbus Day	October	Second Monday
Veterans Day	November	11
Thanksgiving Day	November	Fourth Thursday
Christmas Day	December	25

VI. Billing

A. Meter Data

Meter data for service rendered in accordance with this rate will not be combined for billing purposes unless SMUD determines it is necessary or convenient to do so.

B. Proration of Charges

Charges are prorated when the billing period is less than 27 days, more than 34 days or spans more than one season. The System Infrastructure Fixed Charge and Site Infrastructure Charge will be prorated as shown in the following table.

Billing Circumstance	Basis for Proration
Bill period is shorter than 27 days	Relationship between the length of the billing period and 30 days.
Bill period is longer than 34 days	
Seasons overlap within bill period	Relationship between the length of the billing period and the number of days that fall within the respective season.

C. Contract Capacity

Use of Contract Capacity for billing is at SMUD's sole discretion. Refer to Rule and Regulation 1 and Rule and Regulation 6.

D. Discontinuance of Service

Any customer resuming service at the same premise within 12 months after discontinuing service will be required to pay the System Infrastructure Fixed Charges and Site Infrastructure Charges that would have been billed if service had not been discontinued, except when a customer agrees to lock out service during the full period. The System Infrastructure Fixed Charge and Site Infrastructure Charge will be waived during each of those months. Retroactive billing shall be at SMUD's sole discretion.

(End)

Electricity Facts Label (EFL)

TXU Energy Retail Company LLC
TXU Energy Business Monthly Saver 36℠
Oncor Electric Delivery
January 29, 2015

Electricity Price

Average Monthly Use	1500 kWh	2500 kWh	3500 kWh
Average price per kWh	14.3¢	15.5¢	15.2¢
Average Price per kWh during the Discount[1] period	10.9¢	13.5¢	13.8¢

The average prices per kWh above are based on the specified monthly kWh consumption using a Billing Demand of 7 kW for 1,500 kWh, 11kW for 2,500 kWh, and 16kW for 3,500 kWh and a 30% load factor. Your average price per kWh for electric service will depend on your usage and the following pricing components:

		Per Month
Base Charge	Per ESI ID:	$9.95
		per kWh
Energy Charge	All kWh	10.1000¢

TDU Delivery Charges:

Transmission and Distribution Utility ("TDU") Charges for delivering electricity will be passed through to customer with no increase or markup. For updated TDU delivery charge factors go to txu.com/tduchargesbiz.

Average prices per kWh listed above do not include facility relocation fees or other charges ordered by a municipality. For more information, see txu.com/municipalfees.

Sign-in at 'MyAccount' on txu.com for details or call 1-888-399-5501.

Other Key Terms and Questions

You will receive a discount consisting of a Monthly Savings bill credit of $25 on your bill when usage in a month falls between 500-799 kWh or a total of $50 when your monthly usage is equal to or greater than 800 kWh.

Each month you will also be billed all taxes, including sales tax and reimbursement for the state miscellaneous gross receipts tax as applicable.

See Terms of Service Agreement for a full listing of fees, deposit policy, and other terms.

Disclosure Chart

Type of Product	Fixed Rate
Contract Term	36 Months
Do I have a termination fee or any fees associated with terminating service?	Yes Early cancellation fee is the greater of one-sixth of the estimated billing for the remainder of the term for electric service per ESI ID, or $300.00 per ESI ID.
Can my price change during the contract period?	Yes
If my price can change, how will it change, and by how much?	TXU Energy believes that customers should be fully informed about their price. Your price will not change during the term of this plan except in the limited circumstances of changes made to reflect actual changes in TDU Delivery Charges; changes to the Electric Reliability Council of Texas or Texas Regional Entity administrative fees charged to loads; or changes resulting from federal, state, or local laws that impose new or modified fees or costs that are beyond our control.
What other fees may I be charged?	See Pricing and Fees Section of your Terms of Service Agreement for non-recurring fees.
Is this a pre-pay or pay in advance product?	No

	Does the REP purchase excess distributed renewable generation?	No	
	Renewable Content	This product is 9 % renewable	
	The statewide average for renewable content is	11%	
	TXU Energy Retail Company LLC P.O. Box 650764, Dallas, TX 75265-0764 972-791-2830 or 1-888-399-5501 (toll free) M-F 7a-7p; Sat 8a-5p CT E-mail address: txuenergy@txu.com Website: txu.com	REP Certificate No. 10004	Version: ALBIZMOSVR36AB January 29, 2015 V20140211
Additional Detail	For an explanation of how your Billing Demand is determined, see the Pricing and Fees section of your Terms of Service Agreement.		

COMMERCIAL GREATER THAN 10kW CHARGE

Description (Online): Updated February 2015	Charge Type by TDU:						
	ONCOR	CenterPoint Energy	AEP TX Central	AEP TX North	TNMP	Sharyland Utilities	Sharyland - McAllen
Per Month Charges:							
Customer Charge	$6.80	$2.26	$3.26	$4.25	$2.56	$16.71	$26.52
Metering Charge	$22.14	$18.82	$15.81	$18.68	$10.74	$24.53	$15.81
Energy Efficiency Cost Recovery Factor	$0	$0	$0	$0	$0	$0	$0
Energy Efficiency Cost Recovery Factor - Remand Surcharge	$0	$2.5781	$0	$0	$0	$0	$0
Advanced Metering Cost Recovery Factor	$3.98	$3.16	$2.05	$1.46	$13.63	$0	$0
Total Per Month Charges:	$32.92	$26.8181	$21.12	$24.39	$26.93	$41.24	$42.33
Per kWh Charges:							
Transition Charge (TC2)	$0	$0.002695	$0	$0	$0	$0	$0
Transition Charge (TC3)	$0	$0.001375	$0	$0	$0	$0	$0
Transition Charge (TC5)	$0	$0.001302	$0	$0	$0	$0	$0
Rate Case Expense Surcharge 2	$0	$0	$0	$0	$0	$0	$0
Energy Efficiency Cost Recovery Factor	$0.000525	$0.000601	$0.000398	$0.000405	$0.000619	$0.000516	$0.000516
Total Consumptions Charges Per kWh:	$0.000525	$0.005973	$0.000398	$0.000405	$0.000619	$0.000516	$0.000516
Per kW Charges:							
Transmission System Charge	$0	$1.431800	$1.286000	$1.245000	$0	$0	$1.790000
Distribution System Charge	$4.380000	$3.059429	$3.314000	$3.210000	$6.098100	$12.290000	$6.950000
Nuclear Decommissioning Fee	$0.044000	$0.001828	$0.003884	$0	$0	$0	$0
Transmission Cost Recovery Factor	$3.481646	$1.104613	$1.634057	$1.181748	$2.833359	$2.308039	$3.831282
Transition Charge (TC1)	$0.172000	$0	$0.912719	$0	$0	$0	$0
Transition Charge (TC2)	$0.267000	$0	$2.243617	$0	$0	$0	$0
Transition Charge (TC3)	$0	$0	$0.863688	$0	$0	$0	$0
Transition Charge (TC5)	$0	$0	$0	$0	$0	$0	$0
Power Cost Recovery Factor Reconciliation	$0	$0	$0	$0	$0	$0	$0
Rate Case Expense Surcharge	$0	$0	$0	$0	$0	$0	$0
Rate Case Expense Surcharge 2	$0	$0	$0	$0	$0	$0.280000	$0
Rate Case Expense Surcharge 3	$0	$0	$0	$0	$0	$0	$0
Rate Case Surcharge (RCE-R)	$0.011400	$0	$0	$0	$0	$0	$0
Storm Recovery Charge	$0	$0.099644	$0	$0	$0	$0	$0
Storm Recovery Tax Credit	$0	($0.031644)	$0	$0	$0	$0	$0
Energy Efficiency Cost Recovery Factor	$0	$0	$0	$0	$0	$0	$0
Competition Transition Charge	$0	$0	$0	$0	$0.451940	$0.110000	$0
Hurricane Cost Recovery Factor	$0	$0	$0	$0	$0	$0	$0
Total Per kW Charges:	$8.356046	$5.665670	$10.257965	$5.636748	$9.383399	$14.988039	$12.571282

COMMERCIAL LESS THAN 10kW CHARGE

Description (Online): Updated February 2015	Charge Type by TDU: ONCOR	CenterPoint Energy	AEP TX Central	AEP TX North	TNMP	Sharyland Utilities
Per Month Charges:						
Customer Charge	$1.71	$1.61	$3.20	$4.25	$2.50	$9.53
Metering Charge	$5.19	$4.41	$3.68	$7.50	$2.20	$13.17
Energy Efficiency Cost Recovery Factor	$0	$0	$0	$0	$0	$0
Energy Efficiency Cost Recovery Factor - Remand Surcharge	$0	$0.0476	$0	$0	$0	$0
Advanced Metering Cost Recovery Factor	$2.39	$3.14	$4.17	$4.40	$8.20	$0
Total Per Month Charges:	$9.29	$9.2076	$11.05	$16.15	$12.90	$22.70
Per kWh Charges:						
Transmission System Charge	$0	$0.004437	$0.002512	$0.003148	$0	$0
Distribution System Charge	$0.020109	$0.012218	$0.015489	$0.031948	$0.033323	$0.044779
Nuclear Decommissioning Fee	$0.000146	$0.000007	$0.000017	$0	$0	$0
Transmission Cost Recovery Factor	$0.006736	$0.004879	$0.003601	$0.004939	$0.013736	$0.009282
Transition Charge (TC1)	$0.000480	$0	$0.008508	$0	$0	$0
Transition Charge (TC2)	$0.000798	$0.002695	$0.017463	$0	$0	$0
Transition Charge (TC3)	$0	$0.001375	$0.008207	$0	$0	$0
Transition Charge (TC5)	$0	$0.001302	$0	$0	$0	$0
Power Cost Recovery Factor Reconciliation	$0	$0	$0	$0	$0	$0
Rate Case Expense Surcharge	$0	$0	$0	$0	$0	$0.001055
Rate Case Expense Surcharge 2	$0	$0	$0	$0	$0	$0
Rate Case Expense Surcharge 3	$0	$0	$0	$0	$0	$0
Rate Case Surcharge (RCE-R)	$0.000067	$0	$0	$0	$0	$0
Storm Recovery Charge	$0	$0.001349	$0	$0	$0	$0
Storm Recovery Tax Credit	$0	($0.000574)	$0	$0	$0	$0
Energy Efficiency Cost Recovery Factor	$0.000437	($0.000097)	$0.000511	$0.000284	$0.008816	$0.000516
Competition Transition Charge	$0	$0	$0	$0	$0.003090	$0.000505
Hurricane Cost Recovery Factor	$0	$0	$0	$0	$0	$0
Total Per kWh Charges:	$0.028773	$0.027591	$0.056308	$0.040319	$0.058965	$0.056137

Also see our Glossary of Invoicing Terms.

Electricity Services

- Why TXU Energy
- About Variable Rate Plans
- Energy Savings Solutions
- Mobile Solutions
- Personal Energy Advisor
- Moving? Visit Our Move Center
- Online Account Management
- Payment Locations
- Set Up Cable, Internet, Phone
- Refer Friends – Get $50
- TXU Energy Blog

For Your Home

- Start New Service
- View & Pay Your Bill
- Move, Add or Change Service
- Paperless Billing
- AutoPay
- Determine Your Current Price
- Average Monthly Billing

Financial Policies — 2015-16

Policy	Current Status
Austin Energy Financial Policies	
1. The term of debt generally shall not exceed the useful life of the asset, and in no case shall the term exceed 30 years.	In compliance.
2. Capitalized interest shall only be considered during the construction phase of a new facility if the construction period exceeds 7 years. The time frame for capitalizing interest may be 3 years but not more than 5 years. Council approval shall be obtained before proceeding with a financing that includes capitalized interest.	N/A
3. Principal repayment delays shall be 1 to 3 years, but shall not exceed 5 years.	In compliance.
4. Austin Energy shall maintain either bond insurance policies or surety bonds issued by highly rated ("AAA") bond insurance companies or a funded debt service reserve or a combination of both for its existing revenue bond issues, in accordance with the Combined Utility Systems Revenue Bond Covenant.	In compliance.
5. A debt service reserve fund shall not be required to be established or maintained for the Parity Electric System Obligations so long as the "Pledged Net Revenues" of the System remaining after deducting the amounts expended for the Annual Debt Service Requirements for Prior First Lien and Prior Subordinate Lien Obligations is equal to or exceeds one hundred fifty per cent (150%) of the Annual Debt Service Requirements of the Parity Electric Utility Obligations. If the "Pledged Net Revenues" do not equal or exceed one hundred fifty per cent (150%) of the Annual Debt Service Requirements of the Parity Electric Utility Obligations, then a debt service reserve fund shall be established and maintained in accordance with the Supplemental Ordinance for such Parity Electric System Obligations.	In compliance.
6. Debt service coverage of a minimum of 2.0x shall be targeted for the Electric Utility Bonds. All short-term debt, including commercial paper, and non-revenue obligations will be included at 1.0x.	In compliance. Debt service coverage (DSC) for the FY 2015-16 Budget is 3.22x.
7. Short-term debt, including commercial paper, shall be used when authorized for interim financing of capital projects and fuel and materials inventories. The term of short-term debt will not exceed 5 years. Both Tax-Exempt and Taxable commercial paper may be issued in order to comply with the Internal Revenue Service Rules and Regulations applicable to Austin Energy. Total short-term debt shall generally not exceed 20% of outstanding long-term debt.	In compliance.
8. Commercial paper may be used to finance capital improvements required for normal business operation for Electric System additions, extensions, and improvements or improvements to comply with local, state and federal mandates or regulations. However, this shall not apply to new nuclear generation units or conventional coal generation units.	In compliance.

Financial Policies — 2015-16

Policy		Current Status
	Commercial paper will be converted to refunding bonds when dictated by economic and business conditions. Both Tax-Exempt and Taxable refunding bonds may be issued in order to comply with the Internal Revenue Service Rules and Regulations applicable to Austin Energy. Commercial paper may be used to finance voter approved revenue bond projects before the commercial paper is converted to refunding bonds.	
9.	Ongoing routine, preventive maintenance should be funded on a pay-as-you-go basis.	In compliance.
10.	Austin Energy shall maintain a minimum quick ratio of 1.50 (current assets less inventory divided by current liabilities). The source of this information should be the Comprehensive Annual Financial Report.	In compliance.
11.	Austin Energy shall maintain operating cash equivalent to 45 days of budgeted operations and maintenance expense, less power supply costs.	In compliance
12.	Net Revenue generated by Austin Energy shall be used for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies, and other Austin Energy requirements such as working capital.	In compliance.
13.	The General Fund transfer shall not exceed 12% of Austin Energy three-year average revenues less power supply costs, calculated using the current year estimate and the previous two years' actual revenues less power supply costs from the City's Comprehensive Annual Financial Report.	In compliance.
14.	Capital projects should be financed through a combination of cash, referred to as pay-as-you-go financing (equity contributions from current revenues), and debt. An equity contribution ratio between 35% and 60% is desirable.	In compliance.
15.	A Repair and Replacement Fund shall be created and established. Moneys on deposit in the Repair and Replacement Fund shall be used for providing extensions, additions, replacements and improvements to the Electric System. Net revenues available after meeting the General Fund Transfer, capital investment (equity contributions from current revenues) and 45 days of working capital may be deposited in the Repair and Replacement Fund. The targeted balance shall not exceed 50% of the previous year's electric utility depreciation expense, which is at a level necessary to keep the electric system in good operating condition or to prevent a loss of revenues.	In compliance.
16.	A Strategic Reserve Fund shall be maintained. It will have three components:	In compliance by the end of FY 2015-16.

Financial Policies — 2015-16

Policy	Current Status
· An Emergency Reserve with a minimum of 60 days of non-power supply operating requirements. · Up to a maximum of 60 days additional non-power supply operating requirements set aside as a Contingency Reserve. · Any additional funds over the maximum 120 days of non-power supply operating requirements may be set aside in a Rate Stabilization Reserve. The Emergency Reserve shall only be used as a last resort to provide funding in the event of an unanticipated or unforeseen extraordinary need of an emergency nature, such as costs related to a natural disaster, emergency or unexpected costs created by Federal or State legislation. The Emergency Reserve shall be used only after the Contingency Reserve has been exhausted. The Contingency Reserve shall be used for unanticipated or unforeseen events that reduce revenue or increase obligations such as extended unplanned plant outages, insurance deductibles, unexpected costs created by Federal or State legislation, and liquidity support for unexpected changes in power supply costs for Austin Energy customers. In the event any portion of the Contingency Reserve is used, the balance will be replenished to the targeted amount within two (2) years. A Rate Stabilization Reserve shall be maintained, for the purpose of stabilizing electric utility rates in future periods. The Rate Stabilization Reserve may provide funding for: (1) deferring or minimizing future rate increases, (2) new generation capacity construction and acquisition costs and (3) balancing of annual power supply costs. The balance shall not exceed 90 days of power supply costs. Funding may be provided from net revenue available after meeting the General Fund Transfer, capital investment (equity contributions from current revenue), Repair and Replacement Fund, and 45 days of working capital.	
17. Electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to support (1) the full cost (direct and indirect) of operations including depreciation, (2) debt service, (3) General Fund transfer, (4) equity funding of capital investments, (5) requisite deposits of all reserve accounts, (6) sufficient annual debt service requirements of the Parity Electric Utility Obligations and other bond covenant requirements, if applicable, and (7) any other current obligations. In addition, Austin Energy may recommend to Council in the budget directing excess net revenues for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies and other Austin Energy requirements such as working capital.	In compliance.

Financial Policies — 2015-16

Policy	Current Status
In addition to these requirements, electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to ensure a minimum debt service coverage of 2.0x on electric utility revenue bonds.	
A rate adequacy review shall be completed every five years, at a minimum, through performing a cost of service study.	
18. A decommissioning trust shall be established external to the City to hold the proceeds for moneys collected for the purpose of decommissioning the South Texas Nuclear Project. An external investment manager may be hired to administer the trust investments.	In compliance.
19. The master ordinance of the Parity Electric System Obligations does not require a debt service reserve fund. Austin Energy will maintain a minimum of unrestricted cash on hand equal to six months debt service for the then outstanding Parity Electric System Obligations.	In compliance.
20. Current revenue, which does not include the beginning balance, will be sufficient to support current expenditures (defined as "structural balance"). However, if projected revenue in future years is not sufficient to support projected requirements, ending balance may be budgeted to achieve structural balance.	In compliance.
21. A Non-Nuclear Plant Decommissioning Fund shall be established to fund plant retirement. The amount set aside will be based on a decommissioning study of the plant site. Funding will be set aside over a minimum of four (4) years prior to the expected plant closure.	In compliance.

Appendix E: Proposed Future Research Items

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 AE is recommending preserving most components of the rate structure in this proceeding, AE recognizes that more comprehensive changes may be needed in future rate adjustments to keep up with industry changes.

Therefore, in anticipation of future COS analysis and rate adjustments, and to help ease the disparity of each customer class's revenue recovery and reduce inter-class rate subsidies, AE proposes conducting interim studies to help prepare for a dynamic future. Among the issues anticipated to be studied are the following:

Residential Studies

- *Review tier structure of residential rates:* Austin Energy will study whether and to what extent the residential rates tier structure of promotes the Council's goals for energy efficiency.
- *Lifeline study of minimum residential energy uses:* Minimum residential energy consumption can be used to help determine the boundaries of the lower residential tiers. The study will review minimal residential usage and the factors that determine that level.
- *Study customer-related cost recovery charges for multi-family, single-family, and solar-installed residences:* Austin Energy will investigate whether certain components of the Cost of Service vary by type of residence to improve allocation of costs within the residential sector.
- *Charges for three-phase residential customers:* Data will be collected on residential customers receiving three-phase electric service to determine whether certain components of the Cost of Service vary by service type to improve allocation of costs within the residential sector.

Non-Residential Studies

- *Rate structure for Secondary Voltage Service 1:* Unlike residential customers, with which S1 customers most closely share usage characteristics, the S1 class is billed on a simple uniform energy rate without the benefit of a demand charge to incentivize efficiency. Austin Energy will study alternative rate structures, including a tiered structure for the S1 class that is more similar to the structure of the Residential Class.
- *Downtown Network Rates:* Non-Residential customers on the downtown network are currently charged the same rates as comparable non-Residential customers in each rate class receiving conventional service. Austin Energy will study the Cost of Service to provide network service to determine if there are sufficient differences in non-Residential service costs to warrant separate

rates for customers on the downtown network to improve allocation of costs within the non-Residential sector.

- *Peak Usage Measurement:* Under Austin Energy's tariffs, a non-residential customer recording its highest usage outside of the peak hours for Austin Energy's system-wide peak will incur demand charges equivalent to a customer with highest usage during Austin Energy's system peak. Austin Energy will study the characteristics and determinants of non-residential customers' peak usage, including the extent to which individual customers' peaks are coincident with Austin Energy's system peak, and whether the customers' peaks should be banded for certain afternoon hours. Banding the measurement of the peak hours could preclude customers whose highest demand occurs in non-peak hours from assessment of certain demand charges.

- *Power Factor Charges:* Austin Energy assesses charges for customers with monthly Power Factor below 90 percent according to the Power Factor Correction found in the non-residential tariffs. Austin Energy will assess whether a reactive power charge, also known as kilovolt-ampere reactive ("kvar"), is a feasible and appropriate alternative to the Power Factor Correction.

Appendix F: White Paper — Understanding Austin Energy's Market Competitiveness Metric

In February of 2014, the Austin City Council adopted a two part affordability goal for Austin Energy ("AE"): (1) that overall rates rise no more than 2 percent annually, and (2) that AE's rates remain in the lower 50 percent of rates in the State. The second part of the Council goal is the subject of this White Paper. The goal to remain in the lower 50 percent of rates in the State is a measure of the competitiveness of AE's rates with the rates of other entities in the State providing retail electric service.

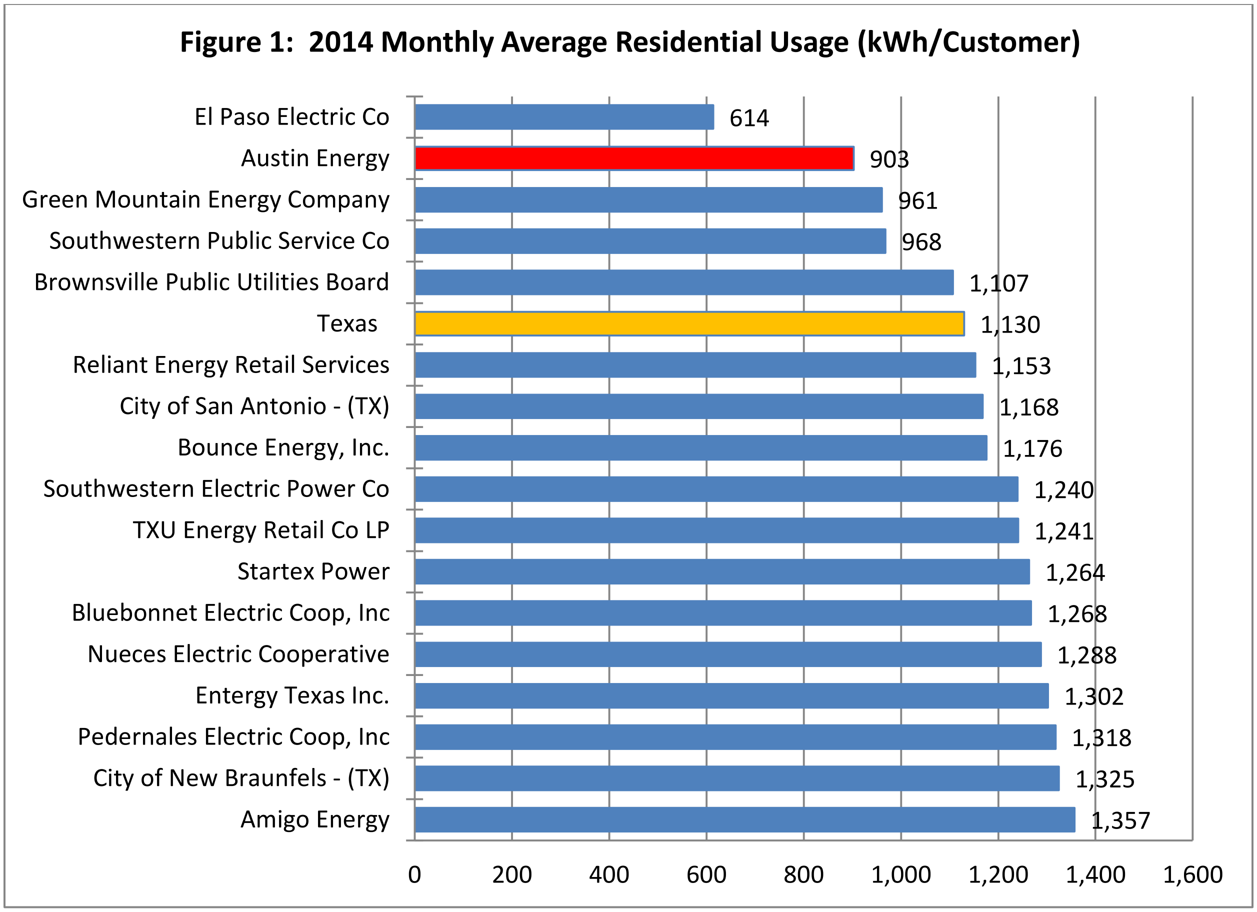
Comparing AE's rates with rates of other electric providers is more challenging than it might at first appear. In much of the State, customers are served in the competitive market by Retail Electric Providers ("REPs"). Austin Energy provides a fundamentally different product, and offers more extensive services than are offered by REPs operating in the competitive market. In providing those services, AE incurs costs that are not incurred by competitive REPs. Those additional costs are reflected in AE's rates.

The prices at which REPs offer electric service are driven by competitive factors, while Austin Energy's rates are set by regulators in a formalized rate-setting process. Competitive market prices and regulated rates may be designed differently and incorporate differing underlying objectives. A further complication is that while AE's rates are published and fully transparent, competitive market prices, particularly for commercial and industrial customers, are often not disclosed publicly. And where direct rate comparisons are possible, the services being provided are not necessarily comparable, creating additional challenges for interpreting results.

Simply comparing electric *rates* may not give a full picture of the differences between Austin Energy and other entities providing electric service in the State. Austin Energy's retail service provides different value components from competitive REPs. In other words, rate comparisons are not necessarily an "apples-to-apples" comparison. Particularly relevant to a more robust comparison are (1) *electric bills*—the full cost of electric service taking usage and other fees/costs into account and (2) services provided by AE that are not provided in competitive territories. Data comparisons presented below indicate that average electric usage is lower for AE customers than for other electric service providers. As a result, average residential *bills* in AE's territory are among the lowest in Texas.

Customer Usage Comparison

Comparing residential usage from the most recently released federal data shows that AE remains a good value for its customers when both usage and rates are taken into account. Figure 1 presents average residential usage for customers of Austin Energy compared to a set of retail electric providers from across the State using recently released federal data for calendar year 2014. The figure clearly shows that average usage by customers of Austin Energy is among the lowest in the State (more than 20 percent lower than the State average), and far lower than several of Austin's neighboring suppliers, including Pedernales and Bluebonnet Electric Cooperatives, City Public Service of San Antonio, and New Braunfels Utilities. These results, which are discussed in more detail below, reinforce that Austin Energy provides a different value than other retail providers.



The total cost of electric service for any customer is determined by the amount of electricity used by that customer and the rates paid for electric service. That Austin Energy customers have significantly lower usage than customers in other parts of the State translates directly into *lower total costs* for AE's customers.

Austin Energy's Rate Design

As a municipal electric utility, AE's rates and its rate-setting process must follow State and local laws and regulations. Austin Energy's rates are set based on cost-of-service—in other words, the rates for each class of customers (*e.g.*, residential, small commercial, large commercial, etc.) must be designed to recover the historical costs of providing those customers' electric service. While Austin Energy's rate structure includes a number of highly innovative features, Austin Energy follows traditional utility rate structure practices, modified within legal guidelines for AE's rate-setting objectives. In AE's 2012 rate review, the rates adopted by City Council reflected a number of policy objectives, a few examples of which included, a higher customer charge to improve fixed cost recovery, tiered residential rates to encourage investments in energy efficiency measures, and compressed summer pricing providing greater incentive for conservation during the summer peak period. The Council also included several "community benefit" charges within AE's rates to create funding sources for specific programs, namely, the Customer Assistance Program (CAP), energy efficiency services, and streetlighting.

Pricing in the Competitive Retail Marketplace

Retail electricity prices of REPs are set according to competitive market and profitability objectives, rather than in a structured rate-setting process. As a REP may change its pricing at any time, prices may vary from one customer to another based on the timing at which each customer entered a service agreement. A REP will bill a retail customer for power and wires services, even though the wires services are provided by a different company, a Transmission and Distribution Utility, which is regulated by the Public Utility Commission of Texas ("PUC" or "Commission"). The REP embeds the costs of wires services into its retail pricing offers.[1]

For residential services, REPs are required by rules of the PUC to present retail pricing offers in a standard format listed on the "Powertochoose.org" website operated by the Commission. Commercial and industrial rates are typically not disclosed publicly, making rates comparisons difficult to carry out.

A review of the Powertochoose.org website reveals a variety of residential electricity pricing structures. Offers are available for a variable or fixed term, with lower prices for shorter terms. Month-to-month offers are typically available for very low prices, with prices rising for offers of six months, one year, two years, and even some three year offers. All prices are denominated in cents per kWh, and there is usually a minimum charge, which may be waived if monthly usage exceeds a predetermined level. And while AE's rates are tiered—increasing with usage—to encourage conservation, in some cases offers on Powertochoose.org are declining with usage, creating an incentive to consume even more. A recent search for retail offers in a Houston zip code resulted in 330 offers. A recent trend apparent in the offers listed on Powertochoose.org is attractive pricing at a narrow usage level, but with higher pricing for lower or higher usage. For example, one 24-month offer from a long-established REP[2] shows pricing at 6.7 cents per kWh at 1,000 kWh per month, 14.5 cents at 500 kWh per month, and 8.7 cents for 2,000 kWh per month.[3] Such a pricing pattern would never be seen in the rates of Austin Energy as this offering does not meet Austin Energy's objectives for transparency, simplicity, and consistency with energy efficiency objectives.

Current pricing offers in the competitive market change—sometimes rapidly—over time by season and with market conditions. Figure 2 below was captured in early 2015 from a website maintained by Centerpoint Energy.[4] It shows the volatility of residential market offers in the Houston area over a 24

[1] Whether a customer's bill shows Transmission and Distribution charges as a separate line item or includes those charges into a single retail cost varies from REP to REP.

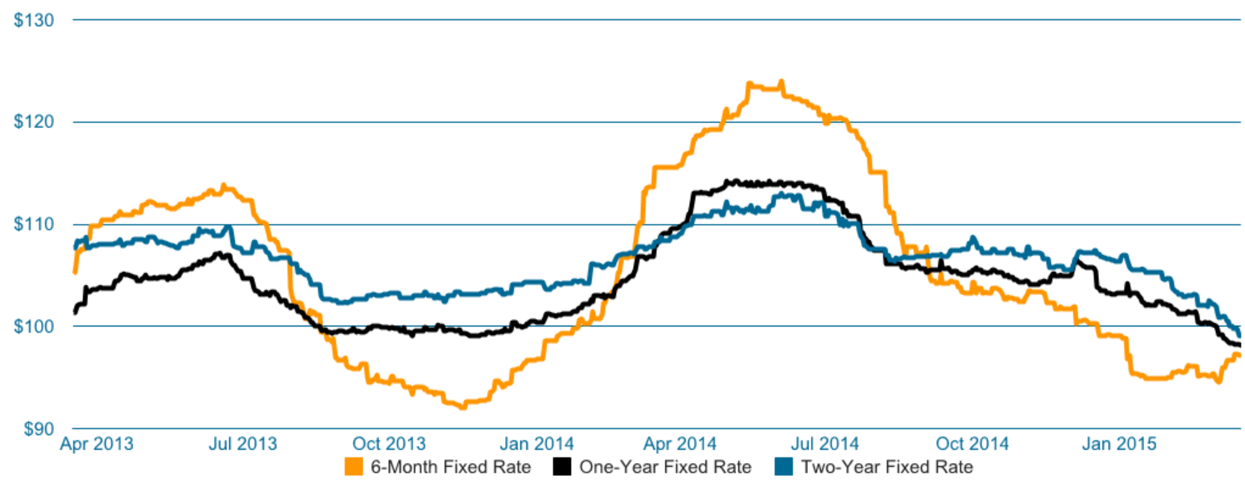
[2] GEXA Choice Select 24 month, from a search on Powertochoose.org on October 19, 2015.

[3] Pricing pattern like that in this example are created through application of a variety of fees and credits. This particular offer includes a fixed fee of $14.95 for use below 1,000 kWh per month and a credit of $40.00 if usage is greater than 999 kWh and less than 2,001 kWh per month. Thus, the customer will see a low average rate between 1,000 and 2,000 kWh, but a substantially higher rate if usage is outside this boundary. There are also a variety of other fees, for example, a fee of $295 for early termination of the 24 month agreement.

[4] See www.mytruecost.com.

month period, for fixed price contracts of 6, 12, and 24 months. The cycles seen in the chart follow closely the price of natural gas, reflecting the process of competitive pricing formation. Wholesale prices in the ERCOT market are set every five minutes based on supply and demand conditions. Typically that price is set at the cost of production of a natural gas fired power plant. Retail Electric Providers will try to lock in the wholesale supply of power for the term of a retail supply contract or for an aggregated set of smaller contracts. Thus, as the price of natural gas varies, a REP will lock in a forward price supporting its expected sales. This is quite different than AE's rate-setting process, where fuel and power supply rates are set based on historic costs.

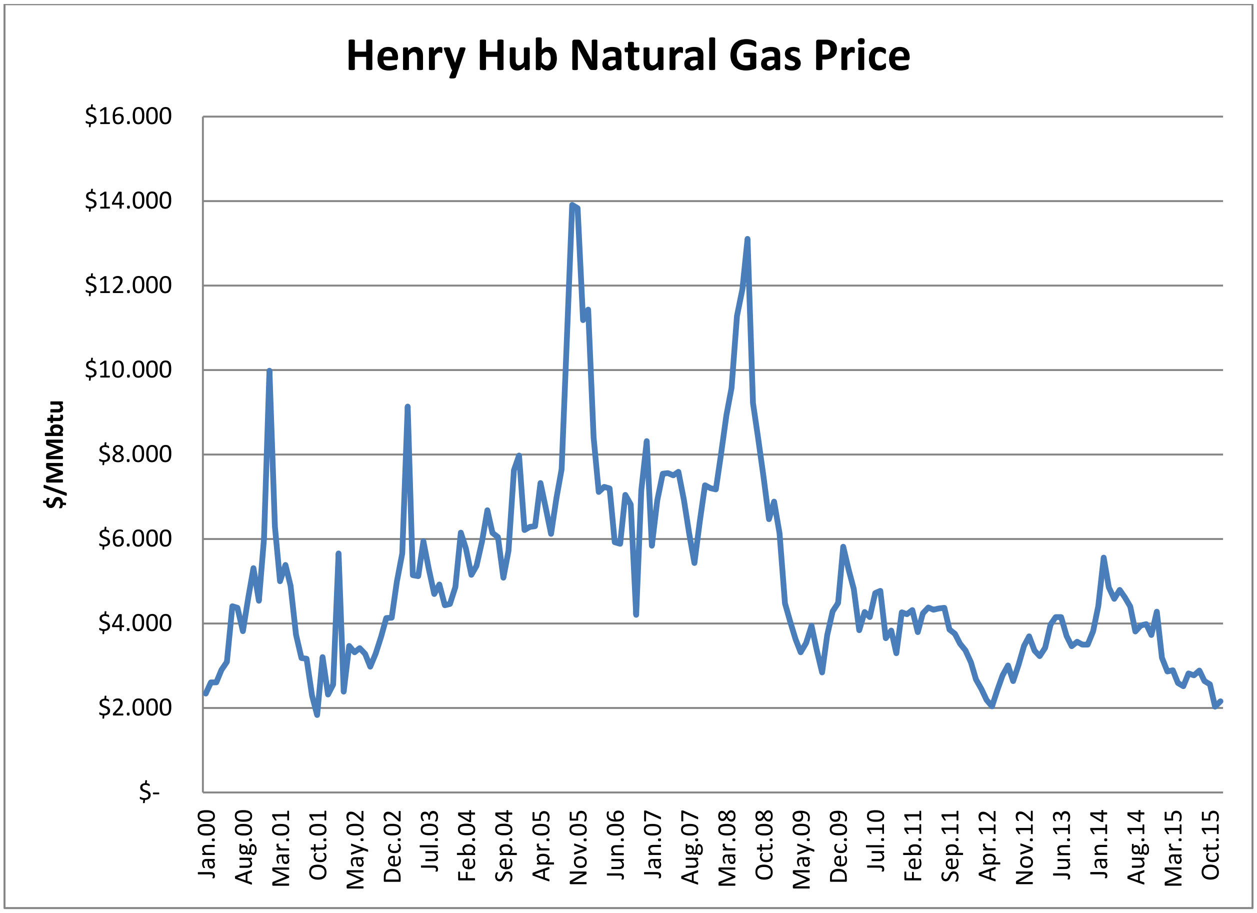
Figure 2: Two-year Trend in ERCOT Residential Pricing Offers (Houston Area)



<u>Austin Energy's Rates vs. Competitive Market Prices</u>

While the energy component of competitive market prices is driven by the current cost of natural gas power production, the energy-related rates of a regulated utility like AE are determined based on the embedded, *i.e.*, historical, costs of its assets and operations. From an economics perspective, market prices are driven by *marginal* costs, while regulated rates are determined by *average* costs. Austin Energy's rates reflect the costs of nuclear, coal, and renewables, as well as natural gas sources. And since the costs of AE's diversified generation portfolio of nuclear, coal, natural gas and renewable resources are more stable than the costs of natural gas-fueled generation resources alone, AE's rates will be more and less competitive with the prices of REPs as gas prices rise and fall. Figure 3 shows the variability in the price of natural gas since the initial deregulation of the retail electric market. Over that time, natural gas prices have varied dramatically in the range of $2.00 per MMbtu to as high as $14.00. The higher the cost of natural gas, the more competitive AE will appear compared to the market, and when the price of gas is in a downcycle, as seen currently with prices below $3.00, AE's rates will appear less competitive. *Should the price of natural gas rebound in the future, AE's rates will again be much more competitive with the deregulated market*. Thus, the relative competitiveness of AE's rates is continually changing with the price of natural gas. The market competitiveness metric of being in the lower 50 percent of rates in the State should be assessed carefully, taking into account long-term trends as well as the then current state of the market for natural gas.

Figure 3: Fifteen-year History of Natural Gas Market Prices



<u>Customer Value Reflected in Electric Rates</u>

Austin Energy offers its customers a different value bundle than the services provided to customers in competitive territories of the State. These differences in value are due to policy objectives of AE and the City Council, in contrast to the profitability objectives driving REP pricing policies. For example, the Council has set aggressive goals for the community for achieving carbon reductions through energy efficiency investments and renewable energy.[5] Accomplishment of these goals brings value to members of the community by reducing electric usage across the entire territory—thereby reducing costs incurred by AE—and reducing the consumption of individual customers. Thus progress toward these goals

[5] State law and Public Utility Commission regulations require that Transmission and Distribution Utilities across the State make investments in energy efficiency programs; however, the scale of programs in AE's territory is believed to be 4 to 5 times the magnitude of those programs in most instances.

reduces the total cost of electricity consumption for the community—a value not necessarily demonstrated in a simple rate comparison.

A variety of other policies embedded in AE's rates produce value for AE's customers. Austin Energy serves all customers in the service territory. In competitive territories, a household or business with difficulty paying its monthly bill may face disconnection in as few as 18 days after the payment due date. Austin Energy's customers, however, are given the option of several deferred payment arrangements before service is disconnected. Among the many community policy priorities embedded in AE's rates are promotion of infrastructure for electric vehicles, "dark sky" compliant street lights, support for the local 311 call center, value of solar pricing for distributed solar installations, forthcoming Community Solar installations, financial support for local economic development initiatives, green building initiatives and programming, utility discounts for residential customers in need, one time bill payment assistance for residential customers facing household emergencies, free weatherization for qualifying low-income households, and walk-up payment centers in otherwise underserved locations in the community. All of these programs provide services to members of the local community that are not typically afforded electric customers in competitive territories of the State.

Austin Energy also provides direct value to the community in its transfer to the City's general fund. Each year, AE transfers 12 percent of its non-power supply revenues to the general fund, providing support for the array of City services and helping to reduce City taxes. The transfer is analogous to the profit of an investor-owned utility, but in this case, all of those profits stay in the local community. Austin Energy also pays a franchise fee to other communities in its service territory, including West Lake Hills, Rollingwood, and Lakeway among others, to assist Austin's neighbors in defraying electric infrastructure costs.

Looking only at AE's rates in comparison to market prices overlooks a fundamental difference between the value provided by AE and the value found in the market. Retail Electric Providers across the State provide electric services. Austin Energy provides electric services and much more. Austin Energy's programs help customers reduce their electric bills and provide a wide array of services to the community. As well, AE's "profits" help fund City services and offset taxes. A simple comparison of average rates and prices therefore overlooks that customers of AE are getting a different value for their dollars. If the sole motivation of the City in its ownership of AE was to generate short-term profits, a number of community programs would be dropped and electric rates would likely be structured differently.

Comparative Data Collected by the U.S. Energy Information Administration

Each year, the Energy Information Administration (EIA) of the U.S. Department of Energy collects and disseminates data on the revenues, sales, and customer counts of electric service providers from across the country. These data can be used at a highly aggregated level to make pricing, usage, and customer bill comparisons. The data—commonly referred to as the "EIA Form 861 data" for the reference number of the form used to collect it—is a lagging indicator. Typically, the data are published in the fourth calendar quarter for the prior calendar year, nearly a year after the year in which it was collected. Thus, the recently released EIA Form 861 data is based on market conditions in place during a window spanning the 12 months of calendar year 2014.

The EIA Form 861 data are reported by each retail entity operating in Texas. These entities include municipally owned utilities, cooperatives, REPs operating in the deregulated portions of the State (essentially the ERCOT region), and Investor-owned Utilities operating in the non-ERCOT portions of the State. Each entity reports on the revenues, sales, and number of customers by customer class. The classes reported include residential, commercial, industrial, and transportation. Using these data, it is possible to calculate for each reporting entity the average price of electric service by customer class for that year (average price = total revenue divided by total usage). The data can also be used to calculate the average usage by customer in each class for that year (average usage = total usage divided by number of customers), as well as average customer bills (average bill = average usage times average price).[6]

Using the EIA Form 861 data for comparing the prices, usage and bills of various entities has advantages and drawbacks. The data are collected and disseminated by an independent third party using generally consistent reporting standards. Because the data are highly aggregated, variations which may arise in a more granular comparison are avoided, making the results more directly comparable. As discussed above, in competitive territories, the price at which each individual customer is served may differ based on the agreed to term of service (*e.g.*, 6 month contract vs. 2 year contract) and the timing at which each customer initiated service. These differences are controlled for by using aggregated data. The results, however, remain somewhat stale due to the time lag in release of the data. Comparisons of residential customer data are likely to be more reliable than for commercial customers, which in turn are more likely to be valid than for industrial customers. The lesser comparability of commercial and industrial customer data is due to several issues. Most fundamentally, different communities may have very different mixes of commercial and industrial customers with varying electricity usage characteristics (*e.g.*, one community is heavily industrial while another hosts more small commercial entities), making those customers more difficult to compare than residential customers, who will generally have more uniform usage characteristics. In addition, the definition of an "industrial" customer may not be entirely uniform from one reporting entity to another. In the non-ERCOT territories of Investor-owned Utilities, the definition of industrial vs. commercial customers will likely be spelled out in the utility's tariffs, but for a REP, the distinction may not be so clear. In its annual filing, AE classifies as an industrial customer any customer equal or greater than 3 MW served on primary service, customers served at transmission voltage, and all customers served under the Large Primary Service Special Contract Rider. Finally, some REPs my specialize in certain types of customers, *e.g.*, a REP selling exclusively to industrial customers or to some other market subsegment, making it difficult to compare between a specialty provider and one that supplies a more general customer base.

[6] Note that "average bill" as defined here is not the same as an actual bill calculated at average usage. For example, because AE has tiered rates, an actual bill at the average 2014 residential usage level of 903 kWh will be computed according to the rate for Tier 2. An "average bill" using the Form 861 data would instead take the average of all usage by all customers being served at every tier level.

In the comparisons presented here, AE has adjusted the data reported for industrial customers to eliminate results reported for entities that exclusively serve industrial customers. In many cases, the excluded entries are "self-serve REPs" that produce power on site to support industrial processes. Examples of these self-serve REPS include refineries and chemical manufacturing. As there are no businesses of this type in AE's territory and no prospects that one of AE's large high tech customers will install utility scale generation resources, it is appropriate to control for self-serve resources. This adjustment improves the comparability of the data to AE's customer base.

Competitiveness as Measured by Average Rates for 2014

In October 2015, the EIA released the Form 861 data for 2014. The time period covered by the report is the second full reporting year following AE's adjustment of base rates—the first base rate adjustment in 18 years. Also during 2014, the price of natural gas hovered near the lowest price for the entire prior decade. Table 1 shows that AE is outside of the lower one-half of all average rates in the State. Austin Energy remains in the lower half for residential customers, but not for commercial and industrial customer classes. Looking further into the data at rates trends over time shows the impact of the natural gas market and AE's recent rate increase on its relative pricing.

Table 1: 2014 Average Electricity Price by Customer Class (cents/kWh)

	Residential	Commercial	Industrial	Total
Austin Energy	11.31	10.40	7.00	9.96
Texas Average	11.82	8.13	6.16	8.94

Source: EIA Form 861. Industrial totals exclude REPs serving industrial customers only.

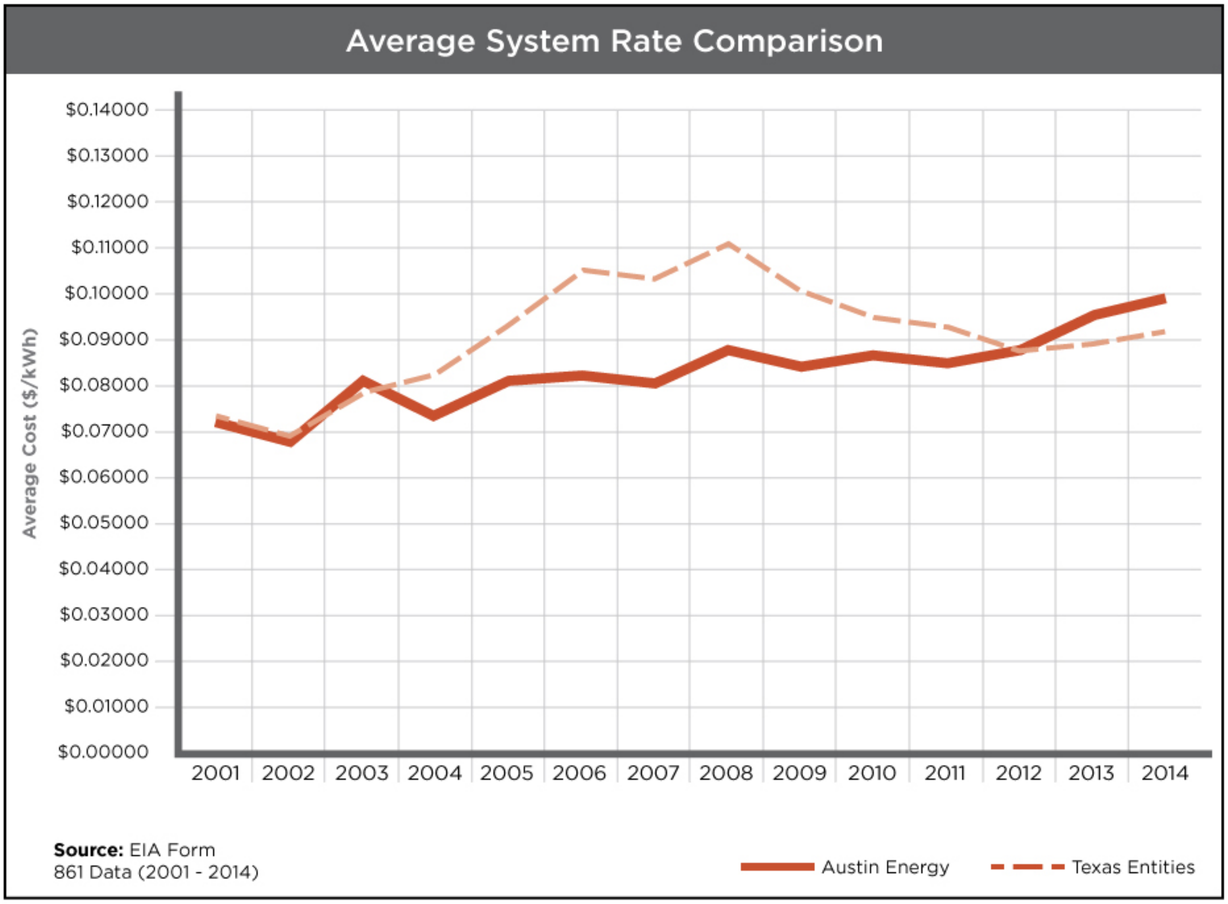
Average Pricing Trends

Reviewing the EIA Form 861 data over the last decade indicates that the average prices of REPs rise and fall with the long term trends in the price of natural gas. During that period, AE's average rates were more stable than competitive market prices of REPs. Figure 4 shows the year-to-year changes in the price of electricity in AE's territory for all customers combined from 2001 to 2014 compared to the Texas average.[7] The average system rates of Austin Energy tracked tightly with the State average during the first years following deregulation. As the price of natural gas rose beginning around 2003, market prices for electricity rose in tandem, while Austin Energy's rates remained more stable. Market prices began to fall after natural gas prices peaked around 2008, while again, Austin Energy's rates remained more stable. From 2003 to 2012, Austin Energy provided its customers millions and millions of dollars of savings below prices they would have otherwise paid in the competitive market. Austin Energy's rates rose in 2013 following the first base rate increase in 18 years at the same time that the natural gas market hit the lowest level seen in a decade. Thus 2012 is the first year since deregulation that Austin Energy's rates exceeded 50 percent of the market. Should the price of natural gas again begin to rise or

[7] To control for "self-serve REPs," resulting in greater comparability to AE's customer base, the Texas average has been adjusted to exclude REPs serving exclusively industrial load. A similar approach is applied in all the values/figures in this report.

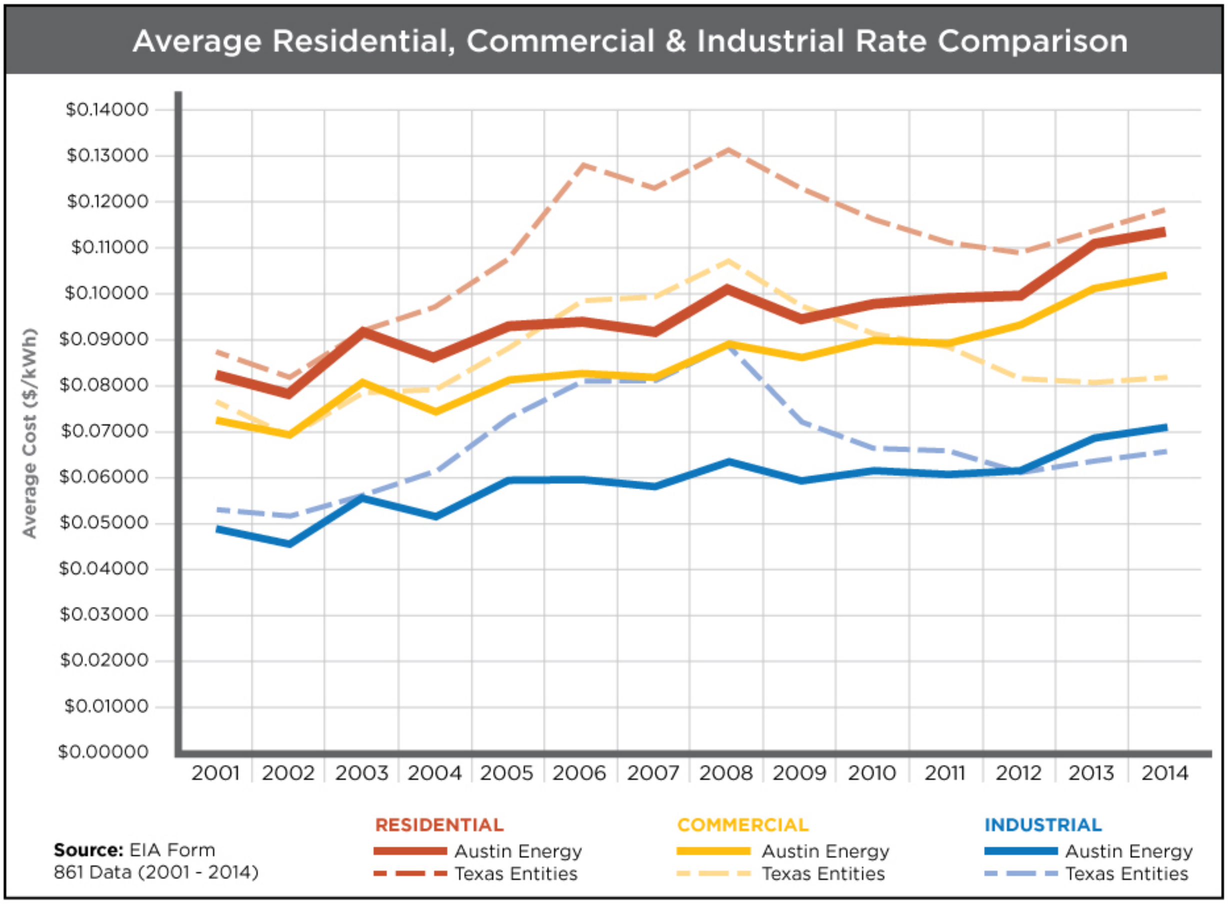
should the price of power in ERCOT rise due to resource limitations, the same pattern will likely repeat where Austin Energy's rates become more competitive with the market.

Figure 4: Austin Energy System Rates Compared to Texas Market Average (2001 – 2014)



During this period, the average rate for power for all AE customers rose from just over 7 cents per KWh to 9.96 cents per kWh in 2014. Figure 5 compares average rates in AE's territory with the Texas average broken out by customer class. For residential customers, AE's rates have remained below the State average from 2003 through 2014. Average rates for AE's industrial customers exceeded the State average for the first time in 2012, and remain somewhat above the State average of 6.16 cents per kWh. In the commercial sector, AE's rates exceed the State average by the largest margin, crossing above the State average initially in 2011.

Figure 5: Austin Energy Rates by Class Compared to Texas Market Average (2001 – 2014)



Comparison of Average Bills

It is also important to recognize that a simple comparison of average prices doesn't capture the value of AE's full array of services. Particularly relevant is a comparison of customer *bills* because a bill is a function of both price and usage. For decades, Austin Energy has emphasized conservation and energy efficiency through a wide array of initiatives, including efficient building codes, rebates and educational programs. Figure 1 (above) presents a comparison of average residential usage in 2013 for a variety of service providers. Average usage by residential customers of Austin Energy is well below that of most other residential retail market participants and well below the Texas average. There are a number of contributing factors to the lower usage of AE's customers, including the mix of multi-family and single-family housing in Austin and characteristics of the housing stock, but in addition to those factors, Austin Energy's decades-long emphasis on providing incentives to install efficiency measures has produced results. Those energy efficiency measures have a demonstrable impact on electricity consumption in the Austin area. As a result, average bills for customers of Austin Energy are lower than those for customers of many other suppliers.

Figure 6: Average Monthly Residential Bill at Actual Average Usage for each Utility (2014 tariffs)

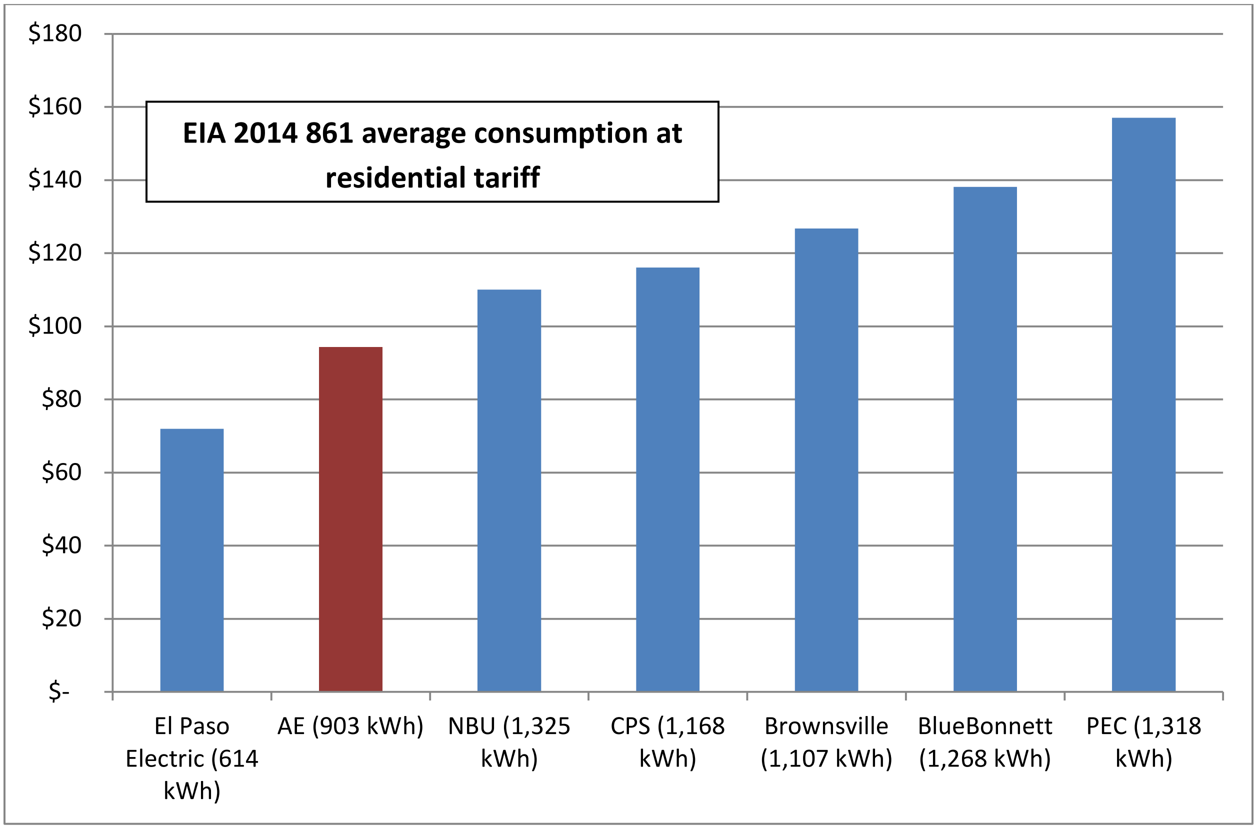


Figure 6 compares average residential bills of Austin Energy customers with other utilities that sell to residential customers at a known rate.[8] The bill is calculated at the 2014 annual average usage level published from the EIA Form 861 data. An average residential bill for a customer of Austin Energy is significantly lower than for any of the neighboring utilities listed. Only customers of El Paso Electric, which has a quite different climate and housing stock, see lower residential bills than customers of Austin Energy.

Summary and Conclusions

Austin Energy's two part affordability goal establishes a goal that AE's rates remain in the lower 50 percent of rates in the State. At this time, federal data for 2014 shows that AE is not meeting that goal for commercial and industrial customers, though the goal is being met for residential customers. Prices in competitive territories of the State track the price of natural gas. As today's prices for natural gas are at the lowest point in over a decade, competitive market prices have fallen below AE's rates, which typically remain much more stable. Should natural gas prices rise in the future or should the market

[8] This comparison includes only electric providers that serve customers under a tariff rate adopted by a local governing body or the Public Utility Commission. Retail Electric Providers offer service to different customers at a variety of different rates. As a result, AE cannot calculate an actual bill for a residential customer of a REP.

price of power in ERCOT rise as the result of resource shortages, market prices may swing back higher dramatically, while AE's rates will remain relatedly stable.

In addition to looking at the relative prices of electric service, AE's rates will differ because AE offers a very different set of services. Community priorities adopted by the City Council are reflected in AE's programs. Those programs, most of which are not available to customer in competitive territories of the State, provide significant value to the community over and above the price of electricity service. For residential customers in particular, AE continues to provide consumer value as average bills for residential customers remain low due to lower average residential consumption in AE's territory.

Appendix G: AE Rate Filing Package

This document is attached separately.

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

US Public Power Electric Utilities With Generation Ownership Exposure

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Summary

This rating methodology explains Moody's approach to assessing credit risk for US Public Power Electric Utilities with Generation Ownership Exposure. This document provides general guidance that helps issuers, investors, and other interested market participants understand how qualitative and quantitative risk characteristics are likely to affect rating outcomes for US public power electric utilities whose credit profile is largely influenced by power generation ownership. This document does not include an exhaustive treatment of all factors that are reflected in Moody's ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.

This rating methodology replaces the US Public Power Electric Utilities with Generation Ownership Exposure Methodology published in November 2011. While reflecting many of the same core principles as the 2011 methodology, this updated document provides a more transparent presentation of the rating considerations that are usually most important for issuers in this sector and incorporates refinements in our analysis that better reflect credit fundamentals of the industry. No rating changes will result from the publication of this rating methodology.

This report includes a detailed rating grid and illustrative examples that compare the mapping of various issuers against the factors in the grid. The grid is a reference tool that can be used to approximate credit profiles within the US public power electric utilities with generation ownership exposure sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to issuers in the US public power electric utility sector whose credit profile is largely influenced by power generation ownership. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the illustrative mapping examples in this document use historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each issuer.

The grid contains five factors that are important in our assessment for ratings in the US public power electric utilities with generation ownership exposure sector:

1. Cost Recovery Framework Within Service Territory

2. Willingness and Ability to Recover Costs with Sound Financial Metrics

3. Generation and Power Procurement Risk Exposure

4. Competitiveness

5. Financial Strength and Liquidity

The scoring for factors 1-5 is aggregated to produce a preliminary grid-indicated rating that is adjusted upwards or downwards based on our view of scoring for factors 6, 7 and 8. Scoring for factors 6-8 can result in upward or downward notching for issuers that exhibit better or worse than typical positions in these areas.

6. Operational Considerations

7. Debt Structure and Reserves

8. Revenue Stability and Diversity

The combination of factors 1-8 results in the grid-indicated rating.

Since an issuer's scoring on a particular grid factor or sub-factor often will not match its overall rating, in Appendix C we include a discussion of some of the grid "outliers" – issuers whose grid-indicated rating for a specific factor or sub-factor differs significantly from the actual rating – in order to provide additional insights.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, legal structure, governance and country related risks, which are not explained in detail in this document, as well as factors that can be meaningful on an issuer-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that would map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A description of factors that drive rating quality

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), a list of the 138 entities currently covered by this rating methodology (Appendix B), tables that illustrate the application of the grid to a representative sample of the covered issuers, with explanatory comments on some of the more significant differences between the grid-implied rating for each factor or sub-factor and our actual rating (Appendix C), and a brief summary of industry issues over the medium term (Appendix D).

Due to the prevalence in this sector of financing secured by a senior net revenue pledge (senior revenue bonds), the grid in this methodology is calibrated for this rating class, and the rating utilized for comparison to the grid-indicated rating is the issuer's senior revenue bond rating. Ratings for individual debt instruments also factor in assessments reflected in notching for seniority level and collateral. The document that provides broad guidance for such notching decisions is the methodology for aligning corporate instrument ratings based on differences in security and priority of claim, which can be found here. All issuers in this sector are owned by government entities in the US, and the grid is calibrated to incorporate the benefits of government ownership. As a result, uplift under Moody's Rating Methodology entitled "Government-Related Issuers" does not apply to this sector.

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. Documents that describe our approach to such cross-sector methodological considerations can be found here.

What Has Changed?

While incorporating the core principles of the 2011 publication, this methodology introduces certain relatively minor changes that better reflect our current thinking.

More specifically, we have extended the lower end of each grid factor to include the B scoring category in order to better capture our views of more challenging political and/or regulatory environments and weaker business models. We have refined the title and scoring descriptions for Factor 3 (Generation and Power Procurement Risk Exposure) to clarify that there is potential risk exposure in both the generation and procurement strategies that a public power electric utility employs to meet its service obligation. We have also refined our definition for Factor 4 (Competitiveness) to better reflect that our view of a public utility's competitiveness is not confined to the historical percentage comparison above or below the state average system price of power as reported by EIA. Instead, our view of competitiveness is forward looking, and a comparison of rates for a key customer class or rates vis-á-vis neighboring utilities may in some cases be more important than a comparison to the state average. In Financial Strength and Liquidity, we have slightly revised the percentage ranges for the Debt Ratio to reflect the leverage we consider to be reasonably consistent with a particular rating category, which takes into consideration the monopolistic but capital intensive nature of this sector and the rate autonomy that public power utilities generally enjoy. Finally, to further improve transparency, we have introduced a new notching factor, "Stability and Diversity of Revenue", and eliminated the less specific "Other" notching factor. We considered all of the previously existing notching assigned under the "Other" category and determined that it could be incorporated into the previously existing "Operational Considerations" and "Debt Structure and Reserves " factors or under "Stability and Diversity of Revenue."

About the Rated Universe

This methodology is applicable to US public power utilities that own significant generation assets or that obtain at least 20% of their capacity/energy from directly owned power generation assets and/or from participation in municipal joint action agencies (JAAs). The issuers rated under this methodology include autonomous US federal, state and local power authorities (e.g. the Bonneville Power Administration, WA

(Aa1/Stable, the Salt River Agricultural Improvement and Power District (Salt River Project; Aa1/stable)), departments of a municipality (e.g., the Los Angeles Department of Water and Power (Aa3/positive) or the San Antonio CPS (Aa1/stable)). The bonds issued by all of these entities are serviced solely from their utility and related operations; they do not represent general obligations of the governments that own or control them. Some of the utilities rated under this methodology are integrated, combining generation with high voltage transmission and lower-voltage distribution systems to sell power directly to end-users. Some issuers rated hereunder do not have distribution systems – they sell the power they generate and/or procure on a wholesale basis to other utilities.

Further characteristics that typify US public power utilities with generation exposure include:

» Near monopoly position in providing an essential service

» Unregulated and independent local rate-setting authority[1]

» Cost structure that is generally lower than investor-owned utilities due to the ability to issue lower cost tax-exempt debt and, for some, the availability under federal statute of federal low cost preference power

» Although not typically subject to income taxes or property taxes, most make payments in lieu of taxes (PILOTs); some also may make payments referred to as General Fund Transfers (GFTs)

» Lack of profit motive or need to generate a return on equity

US public power utilities with generation exposure under the 20% threshold on a sustained basis and those that have only transmission and distribution operations are rated under the US Municipal Utility Revenue Debt methodology. Municipal joint action agencies are entities formed by a group of US municipal utilities (participants) to provide reliable and competitively priced energy or energy related services – typically power, though they may also provide natural gas, electric transmission, or telecommunications services for energy assets. The participating municipal utility systems share an obligation established through a long-term contractual arrangement to cover the JAA's operating, capital, and debt service costs. JAAs are rated under the US Municipal Joint Action Agencies methodology.

Approximately 138 US public power electric utilities with generation exposure are currently rated under this methodology, representing approximately $130 billion of debt outstanding. Of this group, approximately half, with approximately $127 billion of debt outstanding, are issuers that have direct ownership of generation, while the other half, with approximately $3 billion of debt outstanding, are issuers that do not own material generation directly but are participants in one or more JAAs. Most of the electric revenue bond debt outstanding for the US public power sector has been issued by public power electric utility generators, like the Los Angeles Department of Water and Power (Aa3/positive) or San Antonio CPS (Aa1/stable), that own their transmission, distribution and power generation facilities, and correspondingly have ongoing capital programs.

Public power electric utilities that either own significant generation assets or obtain at least 20% of their electricity from directly owned power generation assets and/or from JAA participation generally have more fundamental credit risks than other essential purpose enterprises such as public power electric utilities that do not own generation assets. These fundamental risks include exposure to commodity markets, environmental regulation and larger capital requirements to maintain, refurbish or replace generation assets.

The ratings and outlooks for the 138 entities currently covered by this rating methodology are reflected in Appendix B (e.g.; 71 public power electric utilities that own generation directly and 67 public power electric

[1] Certain exceptions may apply; for example public power utilities in Wisconsin, Indiana, and the US Virgin Islands are subject to regulation

utilities that do not own material generation but are participants in JAAs and receive more than 20% of their power supply through one or more JAA agreements).

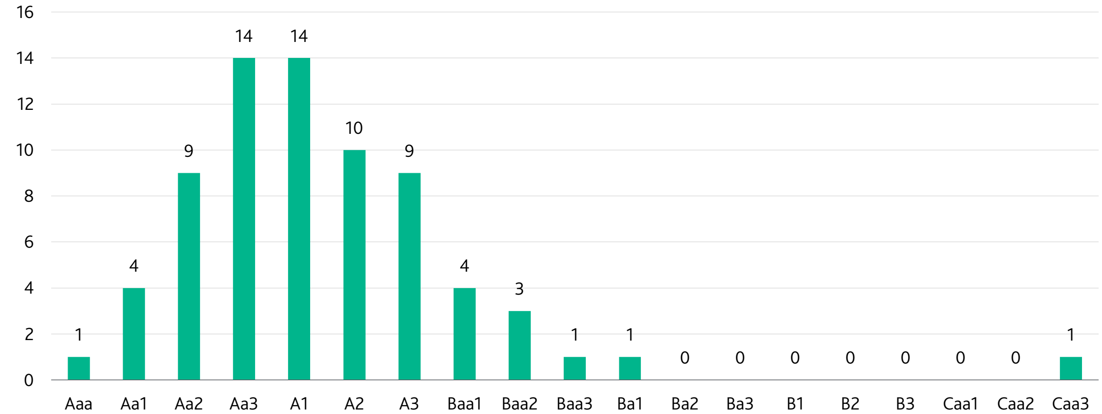
The ratings distribution and history of US public power utilities with generation exposure generally reflects the essentiality of their service, monopoly positions, and, in most cases, autonomous rate-setting ability. However, US public power electric utilities that own generation have a higher degree of business complexity and credit risk than other essential municipal services such as electric and gas distribution, water, sewer, and storm water systems. Specifically, generation-owning electric utilities have greater operating and capital deployment risks, because they have a more complex asset conversion cycle and are subject to ongoing changes in regulations and commodity price that can affect the relative cost-efficiency of their generating fleets. While there remain many similarities with other essential purpose revenue bonds such as governance, bondholder security provisions and rate-setting flexibility, the challenging operating environment for a generation-owning electric utility is more pronounced. While there are some nuanced differences between direct ownership and JAA participation, in broad terms, a public power electric utility shares in the risks associated with JAA generation, and the grid factors are mostly the same for these two sub-groups.

Broad industry changes continue to introduce uncertainty to the public power sector, such as deregulation initiatives that have introduced a degree of competition, ongoing environmental policy changes, and supply and demand factors. Electric generation is capital intensive, and US public power electric utilities with generation exposure must make decisions that result in long-term obligations amidst a changing operating environment.

There have been no bond defaults and no bankruptcies in the past 50 years among US public power utilities with generation exposure, reflecting the sector's fundamental strengths. However, the current rating of one issuer, Puerto Rico Electric Power Authority (Caa3/negative) reflects the expectation of a near-term default. There was a major default in a related public power sector. In 1983, the Washington Public Power Supply System (WPPSS), a JAA, defaulted on approximately $2.25 billion of revenue bonds.

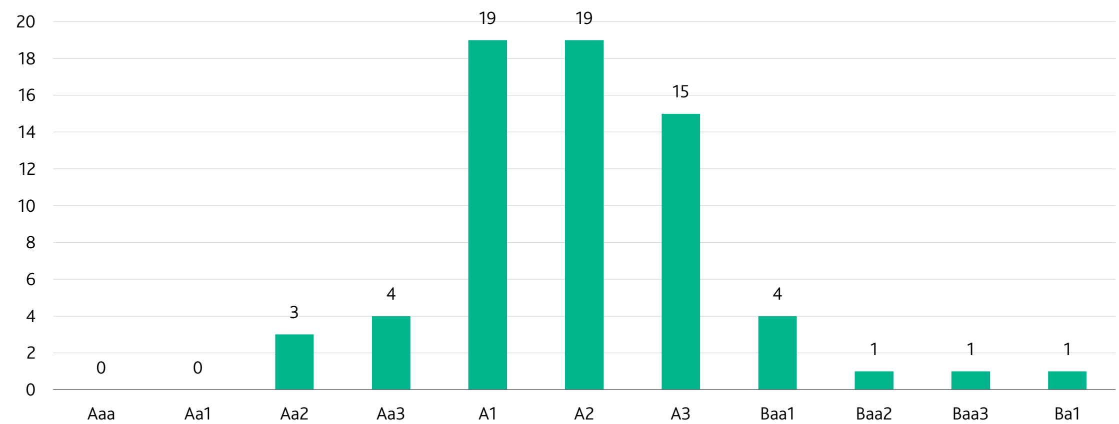
The rating distribution in this sector currently ranges from Aaa to Caa3. The rating distribution of those with directly owned generation is summarized in Exhibit 1, while the distribution for those owning generation through a JAA is summarized in Exhibit 2. In broad terms, the issuers that own material generation have higher ratings on average than those with generation exposure solely via JAAs. This reflects greater fundamental credit strengths in the former sub-group. While issuers that have generation exposure via JAAs have lower ratings on average, this does not typically stem from their JAA participation, which in many cases is an effective generation procurement and diversification strategy for these utilities relative to direct plant ownership.

EXHIBIT 1
Owned Generation Rating Distribution



Source: Moody's Investors Service

EXHIBIT 2
Owned Generation Through JAA Rating Distribution



Source: Moody's Investors Service

About this Rating Methodology

This report explains the rating methodology for US public power electric utilities with generation ownership exposure in several sections, which are summarized as follows:

1. Identification and Discussion of the Grid Factors

The grid in this rating methodology focuses on eight rating factors. One of these factors is comprised of sub-factors that provide further detail. Factors 6-8 are used to make notching adjustments for operational considerations, debt structure and reserves, and revenue stability and diversity.

EXHIBIT 3
US Public Power Electric Utilities with Generation Ownership Exposure Methodology Factor Grid

Grid Factors	Factor Weighting	Sub-Factors	Sub-Factor Weighting
Cost Recovery Framework Within Service Territory	25%		25%
Willingness and Ability to Recover Costs with Sound Financial Metrics	25%		25%

Generation and Power Procurement Risk Exposure	10%		10%
Competitiveness	10%		10%
Financial Strength and Liquidity	30%	Adjusted days liquidity on hand (3-year avg) (days)	10%
		Debt ratio (3-year avg) (%)	10%
		Adjusted Debt Service Coverage OR Fixed Obligation Charge Coverage (3-years avg) (x)	10%
Total	**100%**	**Total**	**100%**
Operational Considerations	(notching adjustment)		
Debt Structure and Reserves	(notching adjustment)		
Revenue Stability and Diversity	(notching adjustment)		

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor or sub-factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the factors and sub-factors is generally found in or calculated from information in utility financial statements, derived from other observations or estimated by Moody's analysts.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of an issuer's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in this document to illustrate the application of the rating grid. However, the factors and sub-factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of one year, several years or more.

The quantitative credit metrics in the grid incorporate any Moody's adjustments to the income statement, cash flow statement and balance sheet amounts.

3. Mapping Grid Factors to the Rating Categories

After estimating or calculating each factor or sub-factor, the outcomes for each of the factors and sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, or B).

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

In Appendix C, we provide a table showing how a representative sampling of 30 utilities in this sector map to grid-indicated ratings for each rating sub-factor and factor. We highlight utilities whose grid-indicated performance on a specific factor or sub-factor is two or more broad rating categories higher or lower than its actual rating and discuss some general reasons for such positive and negative outliers for a particular factor or sub-factor.

5. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

6. Determining the Overall Grid-Indicated Rating

To determine the preliminary grid-indicated rating before notching considerations, we convert each of the factor and sub-factor scores into a numerical value based upon the scale below.

Sub-factor score to numeric value

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

The numerical score for each grid factor or sub-factor is multiplied by the weight for that factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	$x < 1.5$
Aa1	$1.5 \le x < 2.5$
Aa2	$2.5 \le x < 3.5$
Aa3	$3.5 \le x < 4.5$
A1	$4.5 \le x < 5.5$
A2	$5.5 \le x < 6.5$
A3	$6.5 \le x < 7.5$
Baa1	$7.5 \le x < 8.5$
Baa2	$8.5 \le x < 9.5$
Baa3	$9.5 \le x < 10.5$
Ba1	$10.5 \le x < 11.5$
Ba2	$11.5 \le x < 12.5$
Ba3	$12.5 \le x < 13.5$
B1	$13.5 \le x < 14.5$
B2	$14.5 \le x < 15.5$
B3	$15.5 \le x < 16.5$
Caa1	$16.5 \le x < 17.5$
Caa2	$17.5 \le x < 18.5$
Caa3	$18.5 \le x < 19.5$
Ca	$x \ge 19.5$

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 preliminary grid-indicated rating

Finally, we consider whether the preliminary grid-indicated rating score that results from factors 1-5 should be notched upward or downward based on operational considerations, debt structure and reserves, and revenue stability and diversity, in order to arrive at a final grid-indicated rating.

We used a similar approach to derive the grid-indicated ratings shown in the illustrative examples in Appendix C.

7. Appendices

The Appendices provide illustrative examples of grid-indicated ratings based on historical financial information and also provide additional commentary and insights on our view of credit risks in this industry.

Factor 1: Cost Recovery Framework Within Service Territory (25% Weight)

Why It Matters

The ability to recover prudently-incurred costs in a timely manner is one of the most important credit considerations for US public power electric utilities with generation ownership exposure, as a delay in cost recovery may cause financial stress. Therefore, the monopoly status, rate autonomy and where applicable, predictability and supportiveness of the regulatory framework in which a public power utility operates – as well as the legal and political framework that underpins it - are key credit considerations that differentiate this sector from most corporate sectors. In addition, the strength and diversity of the service territory is important because it can indirectly influence a public power electric utility's cost recovery framework. Larger, more diverse service areas with greater economic wealth are better able than smaller, less diverse areas to support rate increases that may be required as a result of changes in fuel and operating costs, required capital expenditures, or other causes.

In general, the US public power electric utilities with generation ownership exposure rated under this methodology are effectively monopoly providers of essential electric services, which limits competitive threats. With few exceptions, they are not subject to rate regulation, i.e. their revenues are not subject to price controls under the jurisdiction of any state public utility service commission as part of the process to reset them periodically. Price-setting mechanisms are generally structured by management, governing boards and or city councils at their sole discretion to limit volatility wherever possible and therefore tend to be highly predictable. The benefits of monopoly status and rate autonomy are further bolstered for most public utilities by minimum bond security covenants that require current revenues to match current expenses, including payment of debt service. There are some instances where regulation of rates by state public utility service commissions does apply. In these instances, the regulators may also have an effect on capital spending decisions and efficiency targets to reduce operating costs, which can affect the public utility's business position.

How We Assess the Cost Recovery Framework Within Service Territory for the Grid

Collectively three components, [1] the strength of monopoly control over a service area, [2] unregulated rate raising ability, and [3] the strength of a public power utility's customer base and service area economy are core characteristics in assessing this factor. In the US, public power electric utilities have maintained a near monopoly role in their service area, limiting competitive threats to their customer base. This monopoly control, in combination with an unregulated rate setting process, provides a greater certainty of the utility's ability to access its revenue requirement from the region served. Among utilities with strong monopolies and autonomous rate-setting (currently the large majority of issuers), assessment of the customer base and service area economic strength provides differentiation for this factor.

When evaluating the credit characteristics of the utility's service area, we consider population, employment trends, wealth indicators, and local economic diversity and growth projections. For example, we often utilize Moody's Economy.com for an assessment of current and projected economic strength of a particular service area. Weak economic characteristics and limited economic diversity would contribute to a lower score for Factor 1.

We also evaluate the wealth indicators of the population that a utility serves to gauge the ability of customers to pay their electric bills, both currently and in the future, if rates rise. Affluent residential customers generally have a higher tolerance for higher overall rates, since the electric bill is a small part of their disposable income.

We look at the relative mix of residential, commercial and industrial customers when assessing the stability of the customer base. Factor scoring for US public power electric utilities that serve a primarily residential customer base (e.g., more than 50% residential sales) would generally be favorably influenced because of benefits from the more stable load and revenue trends that typify the customer class. Alternatively, a customer base dominated by industrial load, particularly if concentrated in one or just a few industrial customers, would exert negative influence on scoring because public utilities with such a characteristic are more susceptible to economic cycles and demand changes that could affect revenue stability.

US public power electric utilities with generation ownership exposure that are subject to rate regulation typically receive lower scores for Factor 1, because rate regulation can sometimes limit or delay cost recovery. Public power electric utilities predominantly have amortizing debt and a debt service coverage requirement, so regulatory lag or cost disallowance that creates uncertainty could increase default risk. For utilities with regulated rate-setting, the regulatory framework can vary by state and may provide greater or lesser predictability in the certainty and timing of cost recovery depending on its details and the manner in which it is applied by regulators. Some states like Wisconsin and Indiana regulate public power electric utilities, but the regulation tends to be credit supportive, and regulators are required to consider bond covenants in their rulemaking. As reflected in the grid, regardless of other considerations in this factor, including service area economic strength and customer concentration, if a public power electric utility falls under typical state regulation (as normally applied to investor owned utilities) our assessment of Factor 1 would typically not exceed a Baa score.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Cost Recovery Framework Within Service Territory	25%	Monopoly with unregulated rate setting and very strong customer base and service area economy	Monopoly with unregulated rate setting and strong customer base and service area credit economy	Monopoly with unregulated rate setting; average customer base and service area economy	Regulation of rates by state; weak customer base / service area economy	Regulation of rates by state with some inconsistency; or very weak customer base or service area economy	Regulation of rates by state is unpredictable; or extremely weak customer base or service area economy

Factor 2: Willingness and Ability to Recover Costs with Sound Financial Metrics (25% Weight)

Why It Matters

Willingness to use the independent and local rate-setting authority guided by sound bond covenants and governance is an extremely important consideration and a heavily weighted rating factor. Unregulated public power utilities may have the ability to raise rates but there can be meaningful differences in their willingness to do so, for a variety of public policy reasons that may have the effect of placing rate-payer concerns ahead of sound financial policy. Regulated public power utilities must have both the willingness to seek rate increases and the ability to obtain the necessary regulatory approvals. In either case, implementing rate increases in a timely fashion in order to maintain sound financial credit strength has been a fundamental credit strength for most issuers in the sector. Credit risk increases in the absence of the stability and certainty that maintenance of a financial buffer provides in mitigating the impact of modest credit stress events. Political risk or (when applicable) lack of regulatory support can result in an unwillingness or inability to establish sufficient rates to maintain sound financial metrics. Without sound rate-setting that is predictable and timely, debt service coverage ratios or liquidity are likely to be compromised. This factor may be a leading indicator of the direction of future financial performance for a US public power electric utility with generation ownership exposure.

Another important aspect is the degree of support, or lack thereof, from a related governmental entity, since most public power electric utilities are owned by local governments. This matters because a city may use its broader governance authority and or financial resources to prevent financial deterioration of the utility, which serves to protect revenue bond holders. Conversely, the government owner can take distributions from the utility, typically in the form of General Fund Transfer (GFTs), that limit the latter's financial flexibility, and the government can pressure the utility to hold down rates or increase capital expenditures in a manner that is detrimental to the maintenance of sound financial metrics.

The ability to automatically adjust rates for changes in fuel or power purchase costs has become a more notable credit factor in the past decade given wide fluctuations in natural gas prices, ongoing hydrology risk, and the volatility of the wholesale power market. Some utilities source a portion of their energy needs in the wholesale market, while others have used profits from wholesale sales to reduce the revenue requirement from retail users.

Rate-setting is a dynamic process that will continue to be tested in the next several years as power supply costs rise due to increased environmental regulation, demand growth remains slow due to the slow economic recovery, and utilities shift to cleaner but sometimes more expensive sources of supply (i.e., to comply with renewable portfolio standards). A forward view of a utility's ability and willingness to set rates to recover all costs has high importance.

How We Assess Willingness and Ability to Recover Costs with Sound Financial Metrics for the Grid

In assessing this factor, we evaluate the governing board's rate-setting process for its transparency, timeliness and supportiveness in setting the rates and charges necessary to ensure that costs, including debt service, are fully recovered. This may include considerations regarding the utility's ability to generate targeted revenue based on underlying volume assumptions. Rate mechanisms that mitigate the impact of revenue volatility are viewed positively.

Another key part of our assessment for this factor is length of time it takes to implement new rates and collect the additional revenues. A demonstrated record of ability and willingness to change rates on a timely or pro-active basis as required to recover operating and capital costs, to provide a cushion for debt service coverage, and to maintain sound liquidity are credit positives and would likely lead to scores at the mid-to-higher end of the rating scale for this factor, when that record is expected to continue. In those cases where utilities waiver and delay on actions to adjust rates as necessary to provide timely assurance of cost recovery, we would likely score them lower for this factor than we would for those who are more proactive in adjusting their rates.

Utilities that have an automatic fuel and purchased power cost adjustment mechanism are able to recover these costs on a more timely basis. Such adjustment mechanisms would typically contribute to a higher score for this factor because the mechanisms serve to narrow the potential drain on liquidity and the resulting impact on credit quality and are of particular importance should there be a fuel price spike or a forced outage of a generating unit. A material lag before the utility can recover these costs would likely contribute to a lower score.

When assessing this factor we also consider the relationship of the local government with the electric utility. This will not always be a material consideration, as some utilities have no fiscal relationship with a local government, or the utility may have been established as a separate and independent authority. We consider who governs the utility, who sets its rates, and who issues the revenue bonds for the utility, as well as the degree to which the general government is responsible for supporting the utility in times of financial stress.

Higher scores for this factor would be likely under circumstances where the interests of the utility and the government are aligned, and where a highly-rated local government has a strong record of supporting their public power electric utility in times of fiscal stress. Political risks and/or regulatory barriers that impede a utility's willingness to enact rates and charges on a timely basis that are sufficient to maintain the associated financial metrics for a utility's rating category would likely result in a lower score for this factor.

Finally, we focus on GFT policies when assessing this factor because the policies are an example of the relationship between a utility and their local government. The GFT is the transfer of surplus utility revenues from the utility to the city's General Fund. Policy-driven GFTs in very limited or conservative amounts typically contribute to higher scores for this factor, while ad hoc, larger amounts of GFTs not governed by policy typically contribute to a lower score. Established, prudent GFT policies that are accepted by both the utility and the local government add credit strength because they increase the predictability of the amount to be transferred. Alternatively, a policy established after a contentious debate for a transfer amount that represents a substantial portion of the utility's own revenues could have a negative impact, (i.e. if it produces uncompetitive electric rates or leaves limited internal funds available for utility operations, maintenance, and repairs) and contribute to a lower score for this factor.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Willingness and Ability to Recover Costs with Sound Financial Metrics	25%	Excellent rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments less than 10 days; No political intervention in past or extremely high support from related government; Very limited General Fund transfers governed by policy	Strong rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 10 to 30 days; Limited political intervention in past or high support from related government; Conservative and well-defined General Fund transfers governed by policy	Adequate rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 31 to 60 days; Some political intervention in past or average support from related government; Moderate General Fund transfers	Below average rate-setting record; Rates, fuel, & purchased power cost adjustments 61 to 99 days; Persistent political intervention or below average support from related government; Large General Fund transfer not governed by policy	Some history or expectation of insufficient rate-setting; Rates, fuel, & purchased power cost adjustments 100 to 120 days; Highly political climate or very limited support from related government; Sizeable General Fund transfer not governed by policy	Lengthy record of, or expectation for a prolonged period of insufficient rate-setting ; Rates, fuel, & purchased power cost adjustments 120 days or more; Highly contentious political climate or clear lack of support from related government; Very sizeable General Fund transfer not governed by policy

Factor 3: Generation and Power Procurement Risk Exposure (10% Weight)

Why It Matters

Generation and power procurement risks, power supply costs and system reliability have an important influence on a utility's ability to meet its service obligations, the competiveness of current and future rates, and financial metrics over time. Efficiently meeting its current electricity demand and planning effectively for future demand has direct bearing on a utility's leverage, customer satisfaction, rate levels, service reliability, and often on the political support for the utility. Political and regulatory support rooted in customer satisfaction can translate into a greater willingness and ability to establish the rate levels needed to keep the utility in sound financial condition.

Successful resource planning, most often accomplished through fuel source diversity and the maintenance of a sufficient but not excessive reserve margin, is fundamental to the utility's future health given the objective to provide low-cost, safe and reliable power supply to its customers. The continuing challenge of managing environmental regulations related to clean air and renewable standards underscores the importance of this factor. These standards can vary by state, have been increasing over time and are often litigated, which typically delays implementation, but may cloud the visibility into the standards that will eventually be enforced.

How We Assess Generation and Power Procurement Risk Exposure for the Grid

When assessing generation and power procurement risks, we consider the mix and diversity of a utility's power supply, as well as the cost and reliability. Maintaining a diverse fuel and resource mix increases the utility's flexibility to manage peak demand while limiting the utility's exposure to volatile commodity and energy market prices, disruptions in the delivery of a single fuel source, or increased costs associated with a particular asset, for instance the cost of environmental compliance for a coal plant. Our review of the utility's generation performance record may include indicators such as availability (% of time a generation unit is operational); capacity factor (% of capacity the generation fleet runs); and heat rates (efficiency of a generator to convert fuel into electrical energy). Additional considerations may include the primary terms and conditions of any purchase power agreements in the context of the utility's overall power supply mix, the positioning of the assets on the regional dispatch curve and the associated impact on the all-in cost of power supply, and the main drivers of the overall retail price charged to the end-use customer. Above-market power supply costs could lead to higher retail charges to end-use customers, which would likely contribute to a lower score for this factor.

We consider the utility's main generation sources, whether owned or purchased under contract, since each type (e.g. natural gas, coal, nuclear, hydro) has risks which must be properly managed. Such risks include fuel price (for instance, natural gas prices can demonstrate high seasonal volatility), transportation issues (e.g., availability of rail and barging delivery for coal, availability of peak period pipeline capacity for natural gas), safety regulations (e.g., Nuclear Regulatory Commission (NRC) regulations for nuclear generation facilities), hydrology risks for hydroelectric generating units, and environmental compliance issues for coal-fired generating units.

In evaluating the generation strategy, we consider the utility's flexibility with regard to fuel-switching. Alternate transportation modes/routes and fuel storage may also be meaningful considerations. By maintaining sufficient power resource reserve margin, a utility is better positioned to manage an unexpected forced outage of a large generating facility. Risk exposures that are not adequately mitigated would contribute to a lower score on this factor.

Public power electric utilities with limited diversification or that are heavily reliant on a single type of generation and fuel source typically score lower on this factor. In some cases, such as high reliance on hydro, the risk may be mitigated somewhat by the cost competitiveness of the fuel source, provided there is ready access to alternative sources of generation. Utilities with a high reliance on coal-fired generation are likely to score lower on this factor due to their vulnerability to future EPA regulations, including under the Clean Power Plan.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Generation and Power Procurement Risk Exposure[2]	10%	Very limited exposure to negative repercussions from generation, procurement and commodity price risks; High degree of diversification of generation and/or fuel sources; Single generation asset typically provides less than 20% of power; or up to 20% of energy from coal-fired generation with carbon mitigation strategy	Limited exposure to negative repercussions from generation, procurement and commodity price risks; Some diversification of generation and/or fuel sources; Single generation asset typically provides less than 40% of power; or up to 40% of energy from coal-fired generation with carbon mitigation strategy	Moderate exposure to negative repercussion from generation, procurement and commodity price risks; Some reliance in one type of generation and/or fuel source, but diversified with purchased power sources; Single generation asset may provide up to 55% of power; or up to 55% of energy from coal-fired generation with carbon mitigation strategy	Moderate to high exposure to negative repercussion from generation, procurement and commodity price risks; Reliance on a single type of generation or fuel source, with somewhat limited diversification via purchased power; Single generation asset typically provides up to 75% of power; or up to 70% of energy from coal-fired generation with carbon mitigation strategy	High exposure to negative repercussion from generation, procurement and commodity price risks; Very high concentration in a single type of generation or very high reliance on a single fuel source, with limited diversification via purchased power; Single generation asset typically provides up to 75% of energy from coal-fired generation with carbon mitigation strategy, or up to 50% of energy from coal with no mitigation strategy	Very high exposure to negative repercussion from generation, procurement and commodity price risks; very high concentration in a single type of generation, almost entirely reliant on a single fuel source, with very limited diversification via purchased power; Single generation asset typically provides over 85% of power; or over 85% of energy from coal-fired generation with carbon mitigation strategy, or over 50% of energy from coal-fired generation with no mitigation strategy

Factor 4: Competitiveness (10% Weight)

Why It Matters

Despite the closed retail market for almost all public power electric utilities, an important advantage of the sector is the price competitiveness for retail and/or wholesale customers, especially relative to investor-owned utilities. We would expect increased political and regulatory risks if the utility has uncompetitive rates, leading to a potentially more challenging rate setting environment despite the rate autonomy that is prevalent in the sector. High retail rates cause pressure on the governing board (and regulators when applicable) to delay rate increases or perhaps even lower rates, which could affect the utility's ability to recover costs and weaken debt service coverage. In addition, high rates may discourage economic development and contribute to a stagnant or declining revenue base, which could impact debt service coverage in the long-run. Public power electric utilities with large, energy-intensive customers that contribute significantly to their net income could face pressure if high industrial or commercial retail rates motivate those large customers to relocate. The shuttering/relocation of large users can weigh negatively on the local economy and also place additional upward pressure on electric rates for the utility's remaining customers.

How We Assess Competitiveness for the Grid

In assessing this factor, we consider a utility's average system retail rate in the context of its regional peers. In many cases, the state average rate is very relevant, but a competiveness comparison to neighboring utilities may be more important for some issuers. For instance, in some states a single utility may dominate, rendering in-state comparisons less meaningful. For public utilities near major metropolitan areas, the

[2] In scoring this factor, generation includes generation from owned assets and via participation in JAAs, unit power agreements and similar arrangements.

important comparison may be to neighboring utilities, especially if there are transmission constraints to in-state utilities that may have a different cost base.

A comparison of retail rates is generally considered in terms of the system average revenue per kilowatt hour (cents/kwh). The average system rate is a useful benchmark that can allow comparisons among regional markets, but it does not distinguish between different customer classes and rate designs. For instance, for some utilities with heavy industrial loads, competitiveness of the industrial rate may be more important than the system average rate, especially if industry is a major driver of employment. For utilities in a contentious political/regulatory environment, residential rates may be most important. For utilities with meaningful wholesale generation, we typically also compare wholesale rates against regional benchmarks to assess the competitive position of that portion of the utility's business, which can be a meaningful consideration, because in most cases the wholesale business is less stable than regulated retail supply.

Our view in this factor is forward-looking, and when relevant we consider future capital spending plans and other cost pressures, such as those for environmental compliance, to assess the likelihood they will create a need for rate increases that pressure the utility's competitive standing.

Generally, those utilities with a stronger competitive starting point compared to the relevant benchmark and that are not facing material cost pressures have more flexibility to withstand competitive challenges and score toward the higher end of the grid for this factor. Competitively challenged utilities, whether on a current basis or prospectively would typically score in the mid-to-lower portion of the grid for this factor.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Competitiveness	10%	Extremely competitive current and expected rates[3] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 25% below state average); and virtually no material prospective cost pressures that could lead to higher rates	Very competitive current and expected rates[3] in the state and/or compared to neighboring utilities on a consistent basis (e.g. average system rates in a range of 7.5% to 25% below state average); very low likelihood of material prospective cost pressures that could lead to higher rates	Competitive current and expected rates[3] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% below state average to 7.5% above state average); modest likelihood of material prospective cost pressures that could lead to higher rates	Somewhat competitive current and expected rates[3] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% to 25% above state average); high likelihood of material prospective cost pressures that could lead to higher rates	Uncompetitive current or expected rates[3] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 25% to 35% above state average); or high likelihood of imminent, material cost pressures that could lead to higher rates	Extremely uncompetitive current or expected rates[3] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 35% above state average); or currently in a period of persistent cost pressures that are causing material rate increases

[3] Retail rates are typically calculated as average revenue per kilowatt hour sold; however, this factor may also be assessed based on competitive positioning of rates in a dominant customer class (residential, commercial, industrial or wholesale).

Factor 5: Financial Strength and Liquidity (30% Weight)

Why it Matters

A utility's ultimate credit profile must incorporate its financial metrics, as any public power utility that is substantially weaker than its peers in terms of liquidity, cash flow generated in relation to debt service, or debt relative to the value of its asset base will generally have a higher probability of default. Public power electric utilities, and especially those that own generation, are typically capital intensive with an ongoing need to invest in their assets and a higher leverage profile than their than their investor-owned counterparts, which typically necessitates consistent access to debt capital markets to assure adequate sources of funding. A utility's financial strength is key to its maintaining this market access and, in general, its long-term viability. Public power electric utilities with weaker metrics may find that their access to markets decreases rapidly when markets shift or their debt load is viewed as unsustainable.

When examining financial strength, there is no single measure that can predict the likelihood of default. We utilize metrics that are indicators for liquidity resources in relation to operating and maintenance expenses, the capacity of the issuer to service its debt and the size of its debt burden relative to its assets. Comparison to peers is typically useful.

How We Assess Financial Strength and Liquidity for the Grid

Adjusted Days Liquidity on Hand Ratio (10% weight)

The formula for Adjusted Days Liquidity on Hand Ratio (days) is as follows:

(Available unrestricted cash and investments + Eligible unused bank lines and capacity under commercial paper programs) x 365 days / (Utility's annual operating and maintenance expenses exclusive of depreciation and amortization expenses)

For the numerator, certain designated reserves (but excluding debt service funds and reserve requirement) that are available when needed by the utility are included in unrestricted cash and investments. The unused portion of eligible bank lines (described below) are included. Capacity under commercial paper programs is included without duplication to unused eligible bank lines. Some utilities have commercial paper programs that are backed by letters of credit, and the unused portion is included when the LC issuing bank is rated P-1.

To be included in this ratio, eligible bank lines must meet all of the following criteria:

- Committed facilities
- Remaining tenor of committed drawdown availability is at least one year
- Absence of impediments to drawdown, including:
  - No material adverse change (MAC) representation requirement for borrowings
  - No material adverse litigation (MAL) representation requirement for borrowings
  - No covenants set at a level reasonably expected to restrict borrowings
- If bilateral, provided by a bank rated P-1
- If syndicated, provided by a group of banks predominantly rated P-1

Bank lines that do not meet the eligibility requirements are not included in calculating the ratio. However, depending on their strength, they may be assessed qualitatively as a credit positive if they constitute incremental liquidity as part of prudent financial policies. While bank lines over a year are included in the ratio, bank line maturities are considered in the broader context of a utility's future cash flow requirements, including capital expenditures, and loan/bond amortizations. Longer dated tenors are more favorable from a credit perspective.

Debt Ratio (10% weight):

(Gross debt – Debt service funds – Interest payable and debt service reserve funds) / (Gross fixed plant assets –Accumulated depreciation on plant + Net working capital)

Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

Adjusted Debt Service or Fixed Obligation Charge Coverage Ratio (10% weight)

In order to improve comparability between utilities that have chosen different generation procurement and financing strategies, there are some differences between their coverage ratios. For public power electric utilities that own all of their generation assets, we use the Adjusted Debt Service Coverage Ratio. For utilities whose generation exposure is undertaken through JAAs (whether entirely or in any part), we use the Fixed Obligation Charge Coverage Ratio.

Adjusted Debt Service Coverage Ratio:

(Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFTs) / Aggregate annual debt service

In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

Most public power utilities transfer a portion of their surplus revenues to a municipal government at an agreed upon level. While the transfers typically come after debt service in the legal flow of funds, in practical terms the transfer is a requirement that in many cases is made on a monthly basis. Therefore, our Adjusted Debt Service Coverage Ratio treats the transfer as akin to an operating expense, which differentiates it from the traditional bond ordinance debt service coverage ratio. We utilize the adjusted debt service coverage ratio in the grid because it provides a better overall indicator of a utility's operating results that provides greater comparability among public power electric utilities. In some cases, the bond ordinance coverage ratio may also be important to our analysis.

Fixed Obligation Charge Coverage Ratio:

(Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFT + Debt service portion of annual payment to JAAs) / (Aggregate annual debt service + Debt service portion of annual payment to JAAs)

In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

Many public power enterprises finance the development or purchase of generation assets through JAAs to increase power reliability, diversify the power resource mix, and lower power costs. We view these contractual obligations as fixed and the annual payments as akin to debt service obligations.

Financial Strength and Liquidity	Weight	Aaa	Aa	A	Baa	Ba	B
Adjusted days liquidity on hand[4] (3-year avg) (days)	10%	≥ 250	150 - 250	90 - 150	30 - 90	15 - 30	< 15
Debt ratio (3-year avg)[5] (%)	10%	< 35%	35% - 60%	60% - 75%	75% - 90%	90% - 100%	≥ 100%
Adjusted Debt Service Coverage[6] OR Fixed Obligation Charge Coverage[7] (3-years avg) (x)	10%	≥ 2.5x	2x - 2.5x	1.5x - 2x	1.1x - 1.5x	1x - 1.1x	< 1x

Factors 6, 7, and 8

These factors result in upward or downward adjustments to the preliminary grid indicated rating resulting from factors 1-5. In aggregate, these factors can result in a total of 3 notches up or down from the preliminary grid-indicated rating to arrive at the grid-indicated rating. In the unusual circumstance that the importance of these factors in assessing the issuer's credit profile is greater than can be incorporated within the range of this notching band, they may nonetheless be incorporated in the actual rating – please see Other Rating Considerations.

Factor 6: Operational Considerations

Operational considerations include construction risks and whether the utility is a vital service provider. In aggregate, operational considerations can result in adjustments ranging from 2 notches down to one notch up.

We assess each utility's construction risks and may apply up to 2 negative notches to the preliminary grid-indicated rating in accordance with the construction program's complexity, technical difficulty, scale relative to the size of the utility, and risk-allocation between the utility and its contractors for cost over-runs and delays, including liquidated damages. We may consider feasibility studies and other reports provided by third-party consulting engineers to inform our assessment of the risks associated with a particular project. Risk mitigation may include fixed-price contracts with liquidated damages, performance and payment bonds, and program management oversight. Technological risk is heightened for first-in-kind engineering risks.

[4] Defined as: (Available unrestricted cash and investments + Eligible unused bank lines and capacity under commercial paper programs) x 365 days / (Utility's annual operating and maintenance expenses exclusive of depreciation and amortization expenses). For the numerator, certain designated reserves (but excluding debt service funds and reserve requirement) that are available when needed by the utility are included in unrestricted cash and investments. The unused portion of eligible bank lines are included. Capacity under commercial paper programs is included without duplication to unused eligible bank lines. To be included in this ratio, eligible bank lines must meet all of the following criteria:

- » Committed facilities
- » Remaining tenor of committed drawdown availability is at least one year
- » Absence of impediments to drawdown, including:
  - No material adverse change (MAC) representation requirement for borrowings
  - No material adverse litigation (MAL) representation requirement for borrowings
  - No covenants set at a level reasonably expected to restrict borrowings
- » If bilateral, provided by a bank rated P-1
- » If syndicated, provided by a group of banks predominantly rated P-1

[5] Defined as: (Gross debt – Debt service funds – Interest payable and debt service reserve funds) / (Gross fixed plant assets –Accumulated depreciation on plant + Net working capital). Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

[6] Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFTs) / Aggregate annual debt service. In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

[7] Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFT + Debt service portion of annual payment to JAAs) / (Aggregate annual debt service + Debt service portion of annual payment to JAAs).

We assess whether the utility provides vital services to a very large economic region and may apply up to one positive notch, for instances where the utility serves as a vital transmission provider and generation resource for a variety of utilities in a very large economic region.

Factor 7: Debt Structure and Reserves

In this factor, we consider the utility's debt service reserves, special borrowing arrangements and debt structure. In aggregate, these considerations can result in adjustments ranging from 2 notches down to 2 notches up.

Public power utilities have different approaches to debt service reserve funds. We consider fully funded maximum annual debt service reserve funds to be an important part of revenue bondholder security, particularly during periods of uncertainty in the credit markets. The lack of a debt service reserve fund could result in a downward adjustment of up to one notch. Some utilities have fully cash funded reserves equal to a full year's debt service requirements, others have no debt service reserve fund, and the rest have something in between. For a utility that has less than a full year debt service reserve fund, we also consider the other elements of its liquidity position in determining the level of downward adjustment, which is typically one half or one notch. However, in cases where the utility maintains at least 100 days of liquidity on hand on a sustained basis (see Factor 6: Financial Strength and Liquidity), the downward adjustment may be reduced or eliminated.

Some utilities benefit from preferential borrowing or guarantee arrangements with strong governmental entities. These may provide alternate sources of liquidity, assured borrowing access even when markets are in turmoil, or patient capital that is willing to provide flexibility in the debt terms, e.g. payment-in-kind in lieu of cash interest or deferrable principal payments. When such arrangements are particularly important and are provided by very highly rated government lenders, we may apply uplift of up to two notches.

Most public power utilities primarily use fixed-rate amortizing debt. The use of other types of debt or financing instruments may add meaningful incremental risk that can result in a downward rating adjustment of up to 2 notches. In most cases, the principal risk is an unexpected drain on liquidity resulting, for instance, from short or long-term debt maturities, suddenly higher interest expense, unexpected collateral calls, a decrease in available bank and commercial paper backstop facilities, or market disruptions.

In assessing debt structure, we typically evaluate the existing and projected debt structure, including reliance on short-term debt, bond-covenanted legal protections, the amortization profile (especially bullet, balloon or other large maturities), use of variable rate debt, exposure to interest rate swap agreements, any use of unusual derivatives, and collateral posting requirements. We generally evaluate exposure to unhedged variable rate instruments in relation to the utility's liquidity and its debt management record, including the absolute level of variable rate debt. We may also consider debt management and interest rate swap policies, board oversight of interest rate swaps, and a utility's disclosure of the risks and exposures associated with its debt. Some potential concerns with swaps and other derivatives, depending on their terms, are requirements the utility may face to post mark-to-market collateral and termination rights of the swap counter-party upon occurrence of certain events, such as a downgrade of the utility below a certain rating level. Another important aspect of debt structure is the utility's bond security provisions. Weakness versus the industry norm, for instance a lack of a covenant requiring the utility to set rates sufficient to support a DSCR of at least one times, may lead to a downward adjustment in this factor.

Factor 8: Revenue Stability and Diversity

Revenue stability and diversity considerations include exposure to wholesale power markets and other higher risk businesses, customer concentration and diversity from combined utility operations. In aggregate, revenue stability and diversity considerations can result in adjustments ranging from 2 notches down to one notch up.

In general, public power electric utilities have a very low business risk profile, typically based on their status as monopoly providers of essential services and their ability to set retail rates at a level that allows recovery of all costs, including debt service. Utilities that have meaningful exposure to wholesale power markets or other higher risk businesses (including telephone service) face incremental credit risks, which may include price and revenue volatility, competition, greater liquidity needs and potential asset stranding. Typically, wholesale public power electric utilities sell electricity under long-term power supply contracts with established, financially sound counterparties that ensure cost recovery, and these contracts can insulate them from wholesale markets, provided the counterparty has high credit quality and the contracts can be renewed at maturity. However, some utilities that have excess supply may choose to sell into wholesale energy markets, often utilizing the potentially larger near-term margins earned to limit retail rate increases on native-load retail customers. The latter strategy introduces very meaningful revenue and cash flow volatility, and there is no certainty that wholesale power margins will be achieved, because the price of power and the relative economics of various fuel types can fluctuate widely over time. Wholesale market exposure may be mitigated if the utility has strong liquidity permitting it to withstand a period of lower wholesale energy margins and a timely and transparent rate-setting process that will allow it to recover costs in retail rates when wholesale margins are lower. Material exposure to re-contracting risk, to wholesale purchasers with weak credit quality, to wholesale power markets when mitigants are insufficient, or to other higher risk businesses may result in a downward adjustment of up to 2 notches in this factor.

Large customer concentration can create credit pressure, especially at smaller utilities, because a single large customer (or group of customers in a particular sector) may leave the system without compensating the utility for any outstanding debt used to construct the generation facilities needed to serve that load and may leave the utility with excess power that can only be sold into the wholesale market. Meaningful customer concentration can typically lead to a downward adjustment of one half to one notch in this factor, depending on the level of fixed system costs that would have to be shared with the remaining customer base and the resultant significance of potential rate increases. However, the downward adjustment in this factor may be up to 2 notches in circumstances where a customer is particularly large and engaged in a competitive, cyclical industry or a very weak sector. Customer concentration with a stable university, government, or health care institution may not lead to a downward adjustment unless that customer has a notable weakness.

The presence of other material essential utility services such as water, sewer/wastewater and natural gas in the utility's business mix, i.e. a combined utility enterprise system, may reduce risk by providing revenue diversity that offsets weather-related and seasonal volume fluctuations, or by increasing the enterprise's importance to the municipal owner. When these other utility businesses are well-managed, and depending on the level of diversity and stability they provide, they may result in an upward adjustment of one-half to one notch.

Rating Methodology Assumptions and Limitations, and Rating Considerations That Are Not Covered in the Grid

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that would enable the grid to map more closely to actual ratings. Accordingly, the eight rating factors in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of entities in this sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we cannot disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all entities in any industry such as the quality and experience of management, assessments of governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government or other political interference in some jurisdictions. Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible to precisely express these in the rating methodology grid without making the grid excessively complex and significantly less transparent. Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position, unless these are low rated companies for which liquidity can be a substantial differentiator for relative default risk.

Other Rating Considerations

Ratings encompass a number of additional considerations. These include but are not limited to: the impact of non-core businesses, our assessment of the quality of management, governance, financial controls, liquidity management, event risk, size, and interaction of ratings with government policies and sovereign ratings.

Impact of Non-Core Businesses

This methodology grid is applied to the assessment of issuers whose primary activity is operating a US public power electric utility with generation ownership exposure. Where the utility has or will seek to diversify its operations towards other business types, we consider the impact of such diversification on credit quality. In particular, the ownership of material businesses with a higher credit risk than a US public power electric utility with generation ownership exposure would likely result in an actual rating that is lower than the grid-indicated rating.

Management Strategy

The quality of management is an important factor supporting any issuer's credit strength. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

Governance

Among the areas of focus in governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, ownership structure and working relationship between the board, government stakeholders (e.g., city councils) and management teams.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. The quality of financial statements may be influenced by internal controls, including centralized operations and the proper tone at the top and consistency in accounting policies and procedures. Auditors comments in financial reports and unusual financial statement restatements or delays in regulatory or other required filings may indicate weaknesses in internal controls.

Liquidity Management

Liquidity is an important rating consideration for all US public power electric utilities with generation ownership exposure. We form an opinion on likely near-term liquidity requirements from the perspective of both sources and uses of cash. While liquidity is specifically considered in certain grid factors, when it is very weak, the impact it has on ratings may be much greater than the standard weights for these factors would otherwise imply.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events could include, asset sales, mandated changes in business activities, capital restructuring programs, litigation and material changes that increase payments in lieu of taxes or other similar distributions by the utility to the municipality.

Size

The size and scale of a US public power electric utility with generation ownership exposure has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. However, size can still be a very important factor in our assessment of certain risks that impact ratings, including natural and man-made disasters, event risk, construction risk and access to external funding. While construction risk is specifically considered in certain grid factors, when it is very high relative to the size of the utility, the impact it has on ratings may be much greater than the standard weights for these factors would otherwise imply.

Interaction of Ratings with Government Policies and Sovereign and Sub-Sovereign Ratings

Compared to most industrial sectors, US public power electric utilities with generation ownership exposure are more likely to be impacted by government and related political actions. Credit implications can occur directly through regulation, and indirectly through energy, environmental and tax policies.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

The illustrative mapping of 30 representative issuers results in the following comparison of grid-indicated outcomes to ratings (see Appendix C for details):

» 16 issuers map to their actual revenue bond rating

» 13 issuers have a grid-indicated rating that is one alpha-numeric notch from their actual revenue bond ratings

» 1 issuer has a grid-indicated rating that is two alpha-numeric notches from its actual revenue bond rating

Appendix A: US Public Power Electric Utilities with Generation Ownership Exposure Methodology Factor Grid

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Cost Recovery Framework Within Service Territory	25%	Monopoly with unregulated rate setting and very strong customer base and service area economy	Monopoly with unregulated rate setting and strong customer base and service area credit economy	Monopoly with unregulated rate setting; average customer base and service area economy	Regulation of rates by state; weak customer base / service area economy	Regulation of rates by state with some inconsistency; or very weak customer base or service area economy	Regulation of rates by state is unpredictable; or extremely weak customer base or service area economy

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Willingness and Ability to Recover Costs with Sound Financial Metrics	25%	Excellent rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments less than 10 days; No political intervention in past or extremely high support from related government; Very limited General Fund transfers governed by policy	Strong rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 10 to 30 days; Limited political intervention in past or high support from related government; Conservative and well-defined General Fund transfers governed by policy	Adequate rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 31 to 60 days; Some political intervention in past or average support from related government; Moderate General Fund transfers	Below average rate-setting record; Rates, fuel, & purchased power cost adjustments 61 to 99 days; Persistent political intervention or below average support from related government; Large General Fund transfer not governed by policy	Some history or expectation of insufficient rate-setting; Rates, fuel, & purchased power cost adjustments 100 to 120 days; Highly political climate or very limited support from related government; Sizeable General Fund transfer not governed by policy	Lengthy record of, or expectation for a prolonged period of insufficient rate-setting ; Rates, fuel, & purchased power cost adjustments 120 days or more; Highly contentious political climate or clear lack of support from related government; Very sizeable General Fund transfer not governed by policy

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Generation and Power Procurement Risk Exposure[8]	10%	Very limited exposure to negative repercussions from generation, procurement and commodity price risks; High degree of diversification of generation and/or fuel sources; Single generation asset typically provides less than 20% of power; or up to 20% of energy from coal-fired generation with carbon mitigation strategy	Limited exposure to negative repercussions from generation, procurement and commodity price risks; Some diversification of generation and/or fuel sources; Single generation asset typically provides less than 40% of power; or up to 40% of energy from coal-fired generation with carbon mitigation strategy	Moderate exposure to negative repercussion from generation, procurement and commodity price risks; Some reliance in one type of generation and/or fuel source, but diversified with purchased power sources; Single generation asset may provide up to 55% of power; or up to 55% of energy from coal-fired generation with carbon mitigation strategy	Moderate to high exposure to negative repercussion from generation, procurement and commodity price risks; Reliance on a single type of generation or fuel source, with somewhat limited diversification via purchased power; Single generation asset typically provides up to 75% of power; or up to 70% of energy from coal-fired generation with carbon mitigation strategy	High exposure to negative repercussion from generation, procurement and commodity price risks; Very high concentration in a single type of generation or very high reliance on a single fuel source, with limited diversification via purchased power; Single generation asset typically provides up to 75% of energy from coal-fired generation with carbon mitigation strategy, or up to 50% of energy from coal with no mitigation strategy	Very high exposure to negative repercussion from generation, procurement and commodity price risks; very high concentration in a single type of generation, almost entirely reliant on a single fuel source, with very limited diversification via purchased power; Single generation asset typically provides over 85% of power; or over 85% of energy from coal-fired generation with carbon mitigation strategy, or over 50% of energy from coal-fired generation with no mitigation strategy

[8] In scoring this factor, generation includes generation from owned assets and via participation in Joint Action Agencies, unit power arrangements and similar arrangements.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Competitiveness	10%	Extremely competitive current and expected rates[9] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 25% below state average); and virtually no material prospective cost pressures that could lead to higher rates	Very competitive current and expected rates[9] in the state and/or compared to neighboring utilities on a consistent basis (e.g. average system rates in a range of 7.5% to 25% below state average); very low likelihood of material prospective cost pressures that could lead to higher rates	Competitive current and expected rates[9] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% below state average to 7.5% above state average); modest likelihood of material prospective cost pressures that could lead to higher rates	Somewhat competitive current and expected rates[9] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% to 25% above state average); high likelihood of material prospective cost pressures that could lead to higher rates	Uncompetitive current or expected rates[9] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 25% to 35% above state average); or high likelihood of imminent, material cost pressures that could lead to higher rates	Extremely uncompetitive current or expected rates[9] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 35% above state average); or currently in a period of persistent cost pressures that are causing material rate increases

Financial Strength and Liquidity	Weight	Aaa	Aa	A	Baa	Ba	B
Adjusted days liquidity on hand[10] (3-year avg) (days)	10%	≥ 250	150 - 250	90 - 150	30 - 90	15 - 30	< 15
Debt ratio (3-year avg)[11] (%)	10%	< 35%	35% - 60%	60% - 75%	75% - 90%	90% - 100%	≥ 100%
Adjusted Debt Service Coverage[12] OR Fixed Obligation Charge Coverage[13] (3-years avg) (x)	10%	≥ 2.5x	2x - 2.5x	1.5x - 2x	1.1x - 1.5x	1x - 1.1x	< 1x

9 Retail rates are typically calculated as average revenue per kilowatt hour sold; however, this factor may also be assessed based on competitive positioning of rates in a dominant customer class (residential, commercial, industrial or wholesale).

10 Defined as: (Available unrestricted cash and investments + Eligible unused bank lines and capacity under commercial paper programs) x 365 days / (Utility's annual operating and maintenance expenses exclusive of depreciation and amortization expenses). For the numerator, certain designated reserves (but excluding debt service funds and reserve requirement) that are available when needed by the utility are included in unrestricted cash and investments. The unused portion of eligible bank lines are included. Capacity under commercial paper programs is included without duplication to unused eligible bank lines. To be included in this ratio, eligible bank lines must meet all of the following criteria:

- » Committed facilities
- » Remaining tenor of committed drawdown availability is at least one year
- » Absence of impediments to drawdown, including:
  - No material adverse change (MAC) representation requirement for borrowings
  - No material adverse litigation (MAL) representation requirement for borrowings
  - No covenants set at a level reasonably expected to restrict borrowings
- » If bilateral, provided by a bank rated P-1
- » If syndicated, provided by a group of banks predominantly rated P-1

11 Defined as: (Gross debt – Debt service funds – Interest payable and debt service reserve funds) / (Gross fixed plant assets –Accumulated depreciation on plant + Net working capital). Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

12 Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFTs) / Aggregate annual debt service. In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

13 Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFT + Debt service portion of annual payment to JAAs) / (Aggregate annual debt service + Debt service portion of annual payment to JAAs).

Factors 1-5 Preliminary Grid Indicated Rating

Factors 6, 7, and 8

These factors result in upward or downward adjustments to the preliminary grid indicated rating resulting from factors 1-5. In aggregate, these factors can result in a total of 3 notches up or down from the preliminary grid-indicated rating to arrive at the grid-indicated rating.

Factor 6: Operational Considerations

Operational considerations include construction risks and whether the utility is a vital service provider. In aggregate, operational considerations can result adjustments ranging from 2 notches down to one notch up.

Construction Risks: up to 2 negative notches

Vital Services to a Very Large Economic Region: up to one positive notch

Factor 7: Debt Structure and Reserves

In this factor, we consider the utility's debt service reserves, special borrowing arrangements and debt structure. In aggregate, these considerations can result in adjustments ranging from 2 notches down to 2 notches up.

Debt Service Reserves: up to one negative notch

Preferential Borrowing/Guarantee Arrangements: up to 2 positive notches

Debt Structure: up to 2 negative notches

Factor 8: Revenue Stability and Diversity

Revenue stability and diversity considerations include exposure to wholesale power markets and other higher risk businesses, customer concentration and diversity from combined utility operations. In aggregate, revenues stability and diversity considerations can result adjustments ranging from 2 notches down to one notch up.

Exposure to Wholesale Power Markets and Other Higher Risk Businesses: up to 2 negative notches

Customer Concentration: up to 2 negative notches

Revenue Diversity: up to one positive notch

Grid Indicated Rating

Appendix B: US Public Power Utilities with Generation Exposure - Directly Owned Generation

Electric Enterprise	Rating	Outlook
Anaheim (City of) CA Electric Enterprise	Aa3	STA
Arizona Power Authority, AZ	Aa2	STA
Austin (City of) TX Electric Enterprise	A1	STA
Batavia (City of) IL Electric Enterprise	A1	NEG
Bonneville Power Administration, WA	Aa1[14]	STA
Brownsville Public Utility Board, TX	A2	STA
Bryan (City of) TX Electric Enterprise	A2	STA
Burbank (City of) CA Combined Utility Enterprise	A1	STA
Burlington (City of) VT Electric Enterprise	Baa1	STA
California Dept. of Wtr. Res. (Power Sys.)	Aa2	STA
Chelan County Public Utility District 1, WA	Aa3	STA
Clark County Public Utility District 1, WA	A1	STA
Clatskanie People's Utility District, OR	A3	NEG
Cleveland (City of) OH Electric Enterprise, OH	A3	STA
Colorado Springs (City of) CO Combined Utility Enterprise	Aa2	STA
Colton (City of) CA Electric Enterprise	A2	STA
Confederated Tribes Warm Springs Reservation, OR	A3	STA
Douglas County Public Utility District 1, WA	Aa3	STA
Gainesville (City of) FL Combined Utility Enterprise	Aa2	STA
Glendale (City of) CA Electric Enterprise	Aa3	STA
Grand Island (City of) NE Electric Enterprise	A1	STA
Grand River Dam Authority, OK	A1	STA
Grant County Public Utility District 2, WA	Aa3	STA
Green Island Power Authority, NY	Ba1	STA
Guam Power Authority, GU	Baa2	STA
Hamilton (City Of) OH Electric Enterprise, OH	A3	STA
Hastings (City of) NE Electric Enterprise	A2	STA
Henderson Municipal Power & Light, KY	Baa2	STA
Holland (City of) MI Electric Enterprise	Aa3	STA
Holyoke Gas and Electric Department, MA	A1	STA
Imperial Irrigation District, CA Electric Enterprise	A1	STA
JEA, FL	Aa2	STA
Key West Utility Board, FL	A1	STA
Lafayette (City of) LA Combined Utilities Enterprise	A1	STA
Lakeland (City of) FL Electric Enterprise	Aa3	STA
Lakeview Light and Power, WA	Baa2	STA
Lansing Board of Water & Light, MI	Aa3	STA

[14] Issuer Rating

Electric Enterprise	Rating	Outlook
LCRA Transmission Services Corporation, TX	A1	STA
Lodi (City of) CA	A2	STA
Long Island Power Authority, NY	Baa1	STA
Los Alamos (County of) NM Combined Utility Enterprise	A2	STA
Los Angeles Department of Water & Power, CA Electric Enterprise	Aa3	POS
Lower Colorado River Authority, TX	A2	STA
Manitowoc (City of) WI Electric Enterprise	A1	STA
Memphis (City of) TN Electric Enterprise	Aa2	STA
Modesto Irrigation District, CA	A2	STA
Nebraska Public Power District, NE	A1	STA
New York State Power Authority, NY	Aa1	STA
Omaha Public Power District, NE	Aa2	STA
Orlando Utilities Commission, FL	Aa2	STA
Owensboro (City of) KY Electric Enterprise	A3	STA
Paducah (City of) KY Electric Enterprise	Baa1	STA
Pend Oreille County Public Utility District 1, WA	A3	NEG
Princeton Electric Plant Board, KY	Baa1	STA
Puerto Rico Electric Power Authority, PR	Caa3	NEG
Rochelle (City of) IL Electric Enterprise	A3	STA
Rochester (City of) MN Electric Enterprise	Aa3	STA
Roseville (City of) CA Electric Enterprise	A2	POS
Sacramento Municipal Utility District, CA	Aa3	STA
Salt River Project Agricultural Improvement and Power District, AZ	Aa1	STA
San Antonio (City of) TX Combined Utility Enterprise	Aa1	STA
Seattle (City of) WA Electric Enterprise	Aa2	STA
Snohomish County Public Utility District 1, WA Electric Enterprise	Aa3	STA
South Carolina Public Service Authority, SC	A1	STA
Springfield (City of) IL Electric Enterprise	A3	NEG
Tacoma (City of) WA Electric Enterprise	Aa3	STA
Tallahassee (City of) FL Electric Enterprise	Aa3	STA(m)
Tennessee Valley Authority	Aaa	STA
Turlock Irrigation District, CA	A2	STA
Unified Gov't of Wyandotte Ct/Kansas City, KS Combined Utility Enterprise	A3	STA
Virgin Islands Water & Power Authority, VI	Baa3	STA

US Public Power Utilities with Generation Exposure - Generation through JAA Participation:

Electric Enterprise	Rating	Outlook
Alexandria (City of) MN Electric Enterprise	A1	NOO
Algona (City of) IA Electric Enterprise	Baa1	STA
Atlantic (City of) IA Electric Enterprise	A1	NOO
Azusa (City of) CA Electric Enterprise	A2	STA
Benson (City of) MN Electric Enterprise	Baa2	NOO
Bryan Rural Electric System, TX	A2	NOO
Cedar Falls (City of) IA Electric Enterprise	Aa2	NOO
Coldwater (City of) MI Electric Enterprise	A3	NEG
Cowlitz County Public Utility District 1, WA	A1	NOO
Dalton (City of) GA Combined Utility Enterprise	A2	NOO
Denton (City of) TX Combined Utility Enterprise	A1	NOO
Detroit Lakes (City of) MN Electric Enterprise	A3	NOO
Easley (City of) SC Combined Utility Enterprise	A2	NOO
Elk River Municipal Utilities, MN	Aa3	NOO
Eugene Water & Electric Board, OR Electric Enterprise	Aa3	STA
Fayetteville Public Works Commission, NC	Aa2	STA
Gaffney (City of) SC Combined Utility Enterprise	A3	NOO
Greenville (City of) TX Electric Enterprise	A2	STA
Greenville Utilities Commission, NC	Aa2	STA
Greer Commission of Public Works, SC	A1	NOO
Griffin (City of) GA Combined Utility Enterprise	A3	STA
Harlan Municipal Utilities, IA	A3	NOO
Heber Light & Power Company, UT	A2	STA
Hutchinson (City of) MN Combined Utility Enterprise	A1	NOO
Indianola (City of) IA Electric Enterprise	A2	NOO
Jackson (City of) MN Electric Enterprise	A3	NOO
Jacksonville Beach (City of) FL Combined Utility Enterprise	A1	NOO
Kaukauna (City of) WI Electric Enterprise	A3	NOO
Kissimmee Utility Authority, FL	A1	NOO
Klickitat County Public Utility Dist. 1, WA	A2	NOO
Leesburg (City of) FL Electric Enterprise	A2	NOO
Marshall (City of) MN Combined Utility Enterprise	A3	NOO
Miller (City of) SD Electric Enterprise	Baa1	Neg
Monroe (City of) NC Combined Utility Enterprise	A2	NOO
Moorhead (City of) MN Combined Utility Enterprise	Aa3	NOO
Mount Horeb (Village of) WI Electric Enterprise	A1	NOO
Murray City (City of) UT Electric Enterprise	A2	NOO
New London (City of) WI Combined Util. Ent.	A3	NOO
New Richmond (City of) WI Electric Enterprise	A2	NOO

Electric Enterprise	Rating	Outlook
Newberry (City of) SC Combined Utility Ent	A3	NOO
Newnan Water, Sewerage & Light Commission, GA	A1	NOO
North Branch (City of) MN Electric Enterprise, MN	Baa3	STA
North St. Paul (City of) MN Electric Ent	A2	Neg
Ocala (City of) FL Combined Utility Enterprise	A1	NOO
Oconomowoc (City of) WI Electric Utility Enterprise	A2	NOO
Opelika (City of) AL Electric Enterprise	A1	NOO
Orange City Electric Enterprise, IA	A3	NOO
Pella (City of) IA Electric Enterprise, IA	A2	NOO
Peru (City of) IL Electric Enterprise	A1	NOO
Plymouth (City of) WI Combined Utility Ent.	A2	NOO
Princeton (City of) MN Combined Utility Enterprise	A3	NOO
Redwood Falls (City of) MN Electric Enterprise	A3	STA
Rock Hill (City of) SC Combined Utility Enterprise	A3	STA
Santa Clara (City of) UT Electric Enterprise	Ba1	NOO
Shakopee Public Utilities Commission, MN	A1	NOO
Shelby (City of) NC Combined Utility Enterprise	A1	NOO
Spencer (City of) IA Electric Enterprise	A1	NOO
St. George (City of) UT Electric Enterprise	Baa1	STA
St. James (City of) MN Electric Enterprise	A2	NOO
Stoughton (City of) WI	A2	NOO
Sun Prairie (City of) WI Combined Utility Enterprise	A1	NOO
Sylacauga Utilities Board, AL	Aa3	NOO
Vernon (City of) CA Electric Enterprise	Baa1	STA
Vero Beach (City of) FL Electric Enterprise	A1	NOO
Waunakee (Village of) WI Combined Utility Enterprise	A1	NOO
Waupun (City of) WI Combined Utility Enterprise	A3	NOO
Waverly Municipal Electric Utility, IA	A2	POS

Appendix C: US Public Power Electric Utilities with Generation Ownership Exposure Grid Outcomes and Outlier Discussion

In the table below, positive or negative "outliers" for a given factor or sub-factor are defined as issuers whose grid factor or sub-factor score is at least two broad rating categories higher or lower than a utility's rating (e.g. an A-rated issuer whose rating on a specific sub-factor is in the Ba-scoring category is flagged as a negative outlier for that factor or sub-factor).

Green is used to denote a positive outlier, whose grid-indicated performance for a sub-factor is two or more broad rating categories higher than Moody's rating.

Red is used to denote a negative outlier, whose grid-indicated performance for a sub-factor is two or more broad rating categories lower than Moody's rating.

Issuer	Moody's Rating	Outlook	Grid Rating	Factor 1. Cost Recovery Framework Within Service Territory	Factor 2. Willingness and Ability to Recover Costs with Sound Financial Metrics	Factor 3. Generation and Power Procurement Risk Exposure	Factor 4. Competitive-ness	Factor 5. Financial Strength and Liquidity: Adjusted days liquidity on hand (3 Year Avg)	Factor 5. Financial Strength and Liquidity: Debt ratio (3 Year Avg)	Factor 5. Financial Strength and Liquidity: Adjusted Debt Service Coverage OR Fixed Obligation Charge Coverage (3 Years Avg)	Preliminary Grid Rating	Factor 6. Operat-ional Consider-ations	Factor 7. Debt Structure and Reserves	Factor 8. Revenue Stability and Diversity
Arizona Power Authority	Aa2	Stable	Aa3	Aaa	Aaa	Aa	Aaa	215	110.0%	1.05	Aa3	0	0	0
Austin (City of) TX Electric Enterprise	A1	Stable	A1	Aaa	A	A	Baa	151	45.0%	1.46	A1	0	-0.5	0
Batavia (City of) IL Electric Enterprise	A1	Negative	A1	Aa	A	Baa	Aa	137	28.0%	2.41	Aa3	0	0	-0.5
Bonneville Power Administration, OR	Aa1	Stable	Aa2	Aa	A	Aa	Aa	129	96.0%	1.13	A2	1	1.5	0
Bryan (City of) TX Electric Enterprise	A2	Stable	A2	Aa	A	Baa	A	110	59.0%	1.23	A2	0	0	0
Chelan County Public Util. Dist 1, WA	Aa3	Stable	A2	A	A	A	Aaa	564	65.0%	1.86	A2	-0.5	0	0
Clark County Public Utility District 1, WA	A1	Stable	A2	Aa	A	A	A	88	63.0%	1.66	A2	0	0	0
Cleveland (City of) Public Power	A3	Stable	A3	Baa	A	A	A	145	63.0%	1.3	A3	0	-0.5	0
Colorado Springs (City of) CO Comb. Util Ent.	Aa2	Stable	Aa3	Aa	Aa	A	A	226	59.4%	1.98	Aa3	0.5	-0.5	0
Grand River Dam Authority	A1	Stable	A1	Aa	A	A	Aa	163	60.7%	1.13	A1	0	0	0
Hastings (City of) Electric System, NE	A2	Stable	A2	A	Aa	Baa	Aa	481	29.6%	1.40	A1	0	0	-1
Henderson Municipal Power & Light, KY	Baa2	Stable	Baa1	A	Baa	Ba	Aa	118	15.0%	1.95	A3	0	0	-1
Holland (City of) MI Electric Enterprise	Aa3	Stable	Aa3	A	Aa	Aa	Aa	590	80.0%	2.09	Aa3	0	0.5	-0.5
JEA, FL	Aa2	Stable	Aa3	Aa	Aa	Aa	A	270	77.0%	2.31	Aa3	0	-0.5	0
Lakeland (City of) FL Electric Enterprise	Aa3	Stable	Aa3	A	Aa	Aa	Aa	214	56.9%	1.56	Aa3	0	0	0
LCRA Transmission Services Corporation	A1	Stable	A1	A	Aa	Aaa	A	350	81.2%	1.49	A1	0	0	0
Long Island Power Authority	Baa1	Stable	Baa1	Aa	Baa	A	A	80	129.0%	1.09	A3	0	-0.5	0
Los Alamos (County of) NM Comb. Util. Ent	A2	Stable	A2	A	A	A	A	210	14.2%	1.71	A1	0	0	-1
Los Angeles Dept. of Wtr.& Pwr., CA Elec. Ent.	Aa3	Positive	Aa3	Aa	Aa	Aa	Aa	202	70.7%	1.61	Aa3	0	-0.5	0
Nebraska Public Power District	A1	Stable	A1	A	Aa	Aa	A	231	72.0%	1.25	A1	0	-0.5	0
New York State Power Authority	Aa1	Stable	Aa2	Aaa	Aa	Aa	Aaa	241	49.0%	2.42	Aa1	0	-0.5	0
Orlando Utilities Commission, FL	Aa2	Stable	Aa3	Aa	Aa	Aa	A	281	56.1%	1.77	Aa2	0	-0.5	0
Paducah (City of) KY Electric Enterprise	Baa1	Stable	Baa2	A	Baa	Baa	Ba	50	85.0%	1.18	Baa2	0	0	0

Issuer	Moody's Rating	Outlook	Grid Rating	Factor 1. Cost Recovery Framework Within Service Territory	Factor 2. Willingness and Ability to Recover Costs with Sound Financial Metrics	Factor 3. Generation and Power Procurement Risk Exposure	Factor 4. Competitive-ness	Factor 5. Financial Strength and Liquidity: Adjusted days liquidity on hand (3 Year Avg)	Factor 5. Financial Strength and Liquidity: Debt ratio (3 Year Avg)	Factor 5. Financial Strength and Liquidity: Adjusted Debt Service Coverage OR Fixed Obligation Charge Coverage (3 Years Avg)	Preliminary Grid Rating	Factor 6. Operat-ional Consider-ations	Factor 7. Debt Structure and Reserves	Factor 8. Revenue Stability and Diversity
Pend Oreille County P.U.D. 1, WA	A3	Negative	A3	Baa	A	A	Aaa	272	51.0%	1.37	A2	0	0	-1
Sacramento Municipal Utility District, CA	Aa3	Stable	Aa3	Aa	Aa	Aa	Aaa	186	72.0%	2.09	Aa2	0	-0.5	0
Salt River Proj. Agric. Imp. & Pwr. Dist. AZ	Aa1	Stable	Aa2	Aaa	Aa	Aa	Aa	236	51.8%	2.30	Aa2	0	-0.5	0
San Antonio (City of) TX Combined Util. Ent.	Aa1	Stable	Aa2	Aaa	Aa	Aa	Aa	259	62.9%	1.64	Aa2	0	0	0
South Carolina Public Service Authority	A1	Stable	A2	Aa	Aa	A	A	262	90.1%	1.41	A1	-1	0	0
Turlock Irrigation District, CA	A2	Stable	A2	A	Aa	A	A	229	82.0%	1.33	A2	0	0	0
Virgin Islands Water & Power Authority	Baa3	Stable	Ba1	Ba	Ba	Ba	A	31	86.0%	0.95	Ba1	0	0	0

Outlier Discussion

As depicted above, the only grid indicated rating that is 2 notches away from the actual rating is Chelan PUD's whose Aa3 rating compares to a grid-indicated rating of A2. Chelan PUD's expected improvement in financial profile over time, combined with a high liquidity position and strong risk management, are factors that support the Aa3 actual assigned rating. The following comments provide insights on some of the outliers for factor and sub-factor grid scores.

Cost Recovery Framework Within Service Territory

Austin (City of) TX Electric Enterprise (Austin Energy) and Long Island Power Authority (LIPA) are both positive outliers in this factor. In the case of Austin Energy, this high score is offset by its generation and power procurement risk exposure, in particular relating to its aggressive strategy to take on renewable generation supply resources, while LIPA's strong score in this factor is offset by weaker financial metrics scores.

Willingness and Ability to Recover Costs with Sound Financial Metrics

There are no outliers for this factor.

Generation and Power Procurement Risk Exposure

The lone positive outlier is LCRA Transmission Services Corp., whose Aaa score for this factor reflects its status as a transmission affiliate of Lower Colorado River Authority, with a low business risk profile, offset by scores that are closer to its rating in cost recovery and competitiveness.

Competitiveness

Two positive outliers have strong competitive positions. For Pend Oreille County P.U.D. 1, WA, this is offset by a weaker cost recovery framework and customer concentration. For Henderson Municipal Power & Light this is offset by weaker generation and power procurement risk exposure resulting from a high dependence on coal fired generation as well as revenue stability risks relating to customer concentration and large wholesale power sales to a non-investment grade electric generation and transmission cooperative.

Liquidity-Adjusted Days Liquidity on Hand Ratio

There are 4 positive outliers. LCRA Transmission Corp.'s very strong adjusted days liquidity on hand ratio is offset by its weaker debt ratio and adjusted debt service coverage ratio. For Pend Oreille County P.U.D. 1, WA, this is offset by a weaker cost recovery framework and customer concentration. For Hastings (City of) NE Electric Enterprise, this is offset by weakness in its generation and power procurement risk exposure score and customer concentration. For South Carolina Public Power Authority this is offset by its weaker debt ratio and construction risks related to its nuclear new-build.

Debt Ratio

There are 5 negative outliers and 4 positive outliers. Collectively, the five negative outliers have been through or, in some instances, are still in the midst of large capital programs relying extensively on debt financing to fund the investment costs. Notably, South Carolina Public Service Authority is involved in a large new nuclear plant construction project which contributes to its high debt ratio. In all five cases, significantly stronger cost recover frameworks, willingness and ability to recover costs, generation and power procurement risk exposure and competitiveness offset weakness in this sub-factor.

Batavia (City of) IL Electric System's strong debt ratio, which in part is due to the off-balance sheet treatment of its participation in the Prairie State Project, is offset by weakness in two factors that reflect that exposure - generation and power procurement risk exposure and operational considerations -

construction risk. Hastings (City of) NE Electric Enterprise's off-balance sheet debt is through participation in the Whelan Energy Center (WEC) II project. Hastings is entitled to a 35 MW allocation from the project, of which 25 MWs is currently sub-allocated to the Municipal Energy Agency of Nebraska and Heartland Consumers Power District. Its strong debt ratio is also offset by weakness in generation and power procurement risk exposure and construction risk. For Los Alamos (County of) NM Combined Utility Enterprise, the strong debt ratio is offset by its concentration risk owing to its significant dependence on the Los Alamos National Laboratory. For Henderson Municipal Power & Light, KY (HMPL), its strong score for this sub-factor is offset by weaker scores for generation and power procurement risk exposure, and wholesale power sales to a non-investment grade rated electric generation and transmission cooperative.

Adjusted Debt Service Coverage or Fixed Obligation Charge Coverage

There are 2 negative outliers. Bonneville Power Association's weak Adjusted DSCR is offset by the strength of its cost recovery framework, generation and power procurement risk exposure, and competitiveness, its role as a vital transmission corridor for a very large economic region, and the beneficial US Treasury borrowing line. Arizona Power Authority's weak Adjusted DSCR offsets strong cost recovery framework, willingness and ability to recover costs, and competiveness.

Appendix D: A Summary of Industry Issues over the Intermediate Term

Environmental Compliance Challenges Under Clean Power Plan

On August 3, 2015, the US Environmental Protection Agency (EPA) issued its final regulatory rules on carbon emissions, known as the Clean Power Plan (CPP). The final rule places a limit on carbon emissions from power plants in the US. The rule is undergoing legal challenges but is likely to have a transformative impact on the industry, since it will result in substantially more demand for renewable generation and less demand for coal generation. Natural gas generation will continue to grow but perhaps at an incrementally slower pace. Keeping existing nuclear power plants running may be another method that states will employ to limit their total carbon emission tonnage.

The CPP requires new coal plants to meet a 1,400 lbs/MWh emission requirement, whereas most coal plants emit carbon at a rate of 2,000 lbs/MWh. In theory, new coal plants can adopt ultra super critical technology, capture carbon or mix in some natural gas to bring down the emission level. However, bringing down emissions to 1,400 lbs/MWh will likely be cost-prohibitive in most cases relative to other generation technologies.

Under the new rule, utilities that own coal-fired plants, such as Springfield, Illinois (A3/stable), JEA, Florida (Aa2/stable), will have limited options to reduce carbon output at their coal fired units. They may have to buy carbon credits, run the plants less or retire them early.

Considering that utilities still have several years to become compliant, we do not believe there are broad near-term impacts for these public power utilities. However, power resource planning is a multiyear activity given the capital and operating costs required to ensure system reliability. Some utilities will be better positioned than others, depending on the strategic decisions they make ahead of the final EPA carbon compliance requirement. For example, many utilities have been waiting on the final carbon rule before deciding how to invest in order to make their coal units mercury emissions-compliant. Some will make power supply decisions now, well in advance of the proposed EPA carbon rule compliance deadline, and these strategies may or may not be successful.

Over 300 cities in the Midwest, including Cleveland Public Power (A3/stable), Omaha Public Power District (Aa2/stable) and Hamilton, Ohio (A3/stable), invested upward of $9 billion in revenue bonds to finance new supercritical coal-fired generation units that came online after 2010. Under the EPA's final compliance rule, it is possible that even though these new coal-fired units meet current environmental standards (nitrogen oxides, sulfur oxides and mercury emissions controls), their economic dispatch could be curtailed if states require the facilities to reduce carbon output at the units as part of the state's broader plan. These are the most efficient units, and gains in efficiency are impractical as is co-firing with natural gas.

In general, the strong ability of this sector to recover costs is a meaningful mitigant to the risk that many coal plants may need to be replaced over time with other types of generation. However, the need to recover closed plants will place upward pressure on rates and may curtail the cost competitiveness that has generally characterized the sector.

For further details on Moody's views relating to Environmental Compliance please see related research here.

Potential Implications Of Distributed Generation

Many electricity customers are seeking to get off the electrical grid and self-generate with renewable energy, which means that cost allocation to ensure electricity reliability for all customers has become an increasingly challenging issue for utilities. Concerns about distributed generation centers on the potential loss of customer revenue and the need for the utility to shift its largely fixed costs to remaining customers. To address the cost-shifting problem, we see an increasing focus on changes to rate design by utilities. More specifically, utilities are implementing changes to raise the fixed or demand component of bills for distributed generation customers so that they continue to pay their share of the costs of maintaining the power grid and availability of at-ready generation resources. Most utilities have been proactive in monitoring the cost shift issue. We have seen clear evidence that policymakers are paying attention and addressing this issue. For example, AB 327 was passed in California, which authorizes the regulator to modify rate design. Although cost shifts due to distributed generation have not had a material financial impact on the utilities to this point, the potential exists that more material impact could develop as distributed generation technology advances. In an extreme scenario, the cost shifts could threaten public power utilities' financial performance and undermine the business model, but we do not currently think this is at all likely.

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more secondary or cross-sector credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related secondary and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information.

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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SUMMARY OF AUSTIN ENERGY'S RESERVE FUNDS

Austin Energy

Austin, Texas

PREPARED BY:

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ECONOMICS STRATEGY STAKEHOLDERS SUSTAINABILITY www.newgenstrategies.net

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EXECUTIVE SUMMARY

Municipally Owned Utilities ("MOUs") like Austin Energy ("AE") are cash driven enterprises. To ensure financial stability over the long-run, a MOU's primary concern is to have enough cash, after operating requirements, to meet debt service and infrastructure investment requirements. This financial objective is directly related to the ownership structure of a MOU and is very different from that of an Investor Owned Utility ("IOU"). IOUs are owned by stockholders and are concerned with maximizing their return on investment. When in need of cash, IOUs have access to equity and debt capital markets. By contrast, when MOUs need cash, only debt and cash reserves are options. As a result, it is very common for MOUs to establish financial policies that ensure adequate cash flow and cash reserves in order to successfully manage day-to-day business risk.

Seeking an independent perspective on the adequacy and use of its cash reserves, AE retained NewGen Strategies and Solutions, LLC ("NewGen") to perform an assessment of AE's reserve funds, including a review of supporting financial policies. Specifically, NewGen has reviewed the purpose, use, and funding of the Working Capital Reserve, the Strategic Reserve, the Repair and Replacement Reserve, the Capital Improvement Plan Fund, and the Non-Nuclear Decommissioning Reserve.

Types of Reserves

MOUs establish different types of reserves for different purposes. Reserves are generally either "restricted" or "unrestricted." Restricted reserves are limited in terms of what the funds may be used to pay for and are associated with a specific purpose. Restrictions are generally required and enforced by third parties or legal requirements. For example, a bond reserve is a common reserve with restricted use per the applicable bond ordinance. Cash set aside in such a reserve can only be used to retire debt. Unrestricted reserves are often more flexible and allow the utility to apply funds to a wider range of purposes within predefined limits. The use of unrestricted funds may be defined by utility policy, but the governing body can change or re-purpose its use of these funds, if necessary. Thus, although AE has reserves that it identifies as "restricted," such as the Strategic Reserve, these reserves may only be restricted by City of Austin ("City") designation, which could be changed by Austin City Council ("City Council"). As a result, from the perspective of rating agencies, only reserves that are restricted by external parties, such as restrictions by contract or regulation, are truly restricted. Thus, use of the terms "restricted" or "unrestricted" in this report are consistent with the rating agencies' view of the reserves. However, it is also common for funds dedicated or earmarked for a specific purpose, such as decommissioning or specific capital projects, to be excluded from some rating agency calculations, such as Days Cash on Hand.

Description of Current Reserves

Reserve balances relevant to our analysis at the end of Fiscal Year ("FY") 2014 are shown in Table ES-1. This excludes some restricted reserves – specifically the Bond Reserve and Debt Service Reserve as well as the externally managed Nuclear Decommissioning Trust held by an independent trustee. 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 funds for the eventual decommissioning of AE's share of the South Texas Project. Each of the excluded reserves are considered restricted by AE as well as rating agencies. Thus, they are not included in calculations of financial liquidity, such as Days Cash on Hand.

Table ES-1
Funding Levels for Evaluated Reserves

Reserves	FY 2014 Actual
Working Capital	$ 150,799,894
Strategic Reserve	
Emergency	80,765,286
Contingency	25,811,754
Rate Stabilization	-
Repair & Replacement	64,071
Non-Nuclear Decommissioning	8,138,072
Capital Improvement Plan Fund (1)	78,528,932
Total	$ 344,108,009

Notes:
1) The cash balance for the Capital Improvement Plan Fund was $76,340,936. The remainder of the FY 2014 balance reflected receivables.

A description of each reserve listed in Table ES-1 is as follows:

- **Working Capital:** The Working Capital Reserve[1] (also sometimes referred to as the operating reserve or operating cash) is intended to meet normal day-to-day operation and maintenance ("O&M") expenses, less pass-through costs related to net power supply ("Net Power Supply Cost").[2] Per financial policy, AE must maintain 45 days of budgeted O&M expense, less Net Power Supply Cost.
- **Strategic Reserve:** The Strategic Reserve provides funds to offset revenue or expense fluctuations due to natural disasters or unplanned economic stress. The Strategic Reserve is currently comprised of the following reserve components:

[1] Although not technically a reserve, as it is simply the cash available to facilitate day-to-day operations, we have labeled this the Working Capital Reserve for consistency within the report.
[2] Net Power Supply, as used in this report, includes the cost of fuel, power purchase agreements, net ERCOT revenue, green choice costs not billed to customers directly, regulatory charges associated with the Fuel Adjustment Clause, and the hedging program.

- ***Contingency Reserve***: The Contingency Reserve shall not exceed a maximum of 60 days of O&M expense, less Net Power Supply Cost. This reserve is used for unanticipated or unforeseen events that reduce revenue or increase obligations such as extended unplanned plant outages, insurance deductibles, and unexpected costs created by Federal or State legislation, and liquidity support for unexpected changes in fuel costs or purchased power that stabilizes fuel rates for AE customers.

- ***Emergency Reserve***: The Emergency Reserve must have a minimum of 60 days of O&M expense, less Net Power Supply Cost. This reserve is only used as a last resort after the Contingency Reserve has been exhausted to provide funding in the event of an unanticipated or unforeseen extraordinary need of an emergency nature.

- ***Rate Stabilization Reserve***: The Rate Stabilization Reserve was established to protect customers from higher than anticipated power costs and is intended to defer the need for future rate increases when costs exceed existing rate revenues. Per Financial Policy No. 16, the Rate Stabilization Reserve balance shall not exceed a 90 days of Net Power Supply Cost.

- **Repair and Replacement Reserve**: The Repair and Replacement Reserve has a targeted balance no greater than 50 percent of the prior year's depreciation expense. This reserve is used for extensions, additions, replacement of aging infrastructure, and improvements to the electric system.

- **Non-Nuclear Decommissioning Reserve**: The Non-Nuclear Decommissioning Reserve was established to ensure that adequate funding is available to decommission non-nuclear power plants.

- **Capital Improvement Plan Fund**: The Capital Improvement Plan Fund ("CIP Fund") accrues funds for the equity portion of planned capital projects based on monthly contributions. The CIP Fund is currently funded to pay for the equity portion of capital projects, rather than mitigate risks or offset obligations. The purpose of the CIP Fund is to pay for current capital projects and, therefore, the fund does not act as a reserve – only a funding mechanism for approved capital projects. The CIP Fund is included in this report for completeness and for its relationship to the Repair and Replacement Reserve.

Credit Rating Goal

Although not explicitly identified in financial policies, AE has had in place for many years a financial goal to achieve and maintain a 'AA' credit rating. The first reference to this goal appears in AE's 2003 Strategic Plan. In the 2015 budget, under AE's Mission and Goals for 2015, the utility states the following goal:

> Maintain strong financial position in support of the Utility's Risk Management strategy and achieve improved credit ratings as measured by bond ratings agencies. Achieve the 'AA' credit rating on separate lien electric utility system revenue bonds on the Standard & Poor's rating.

However, AE is currently rated 'AA-' by Fitch, as well as Standard & Poor's, and the median Days Cash on Hand for similarly rated utilities by Fitch is 180 days, which is well in excess of

AE's current level of Days Cash on Hand.[3] Ratings are the result of many factors, and simply attaining (or not attaining) 180 Days Cash on Hand is not, in of itself, cause to upgrade (or downgrade) a utility's rating. In AE's case, there are other factors, such as its relatively low leverage, that have facilitated its 'AA-' rating. However, in order to maintain its current rating, AE is expected to improve its Days Cash on Hand to be more in alignment with its similarly rated peers. In its April 2015 publication, Fitch stated, "Liquidity and cash flow metrics remain somewhat low relative to rating category medians, but additional improvement ***is expected*** based on AE's multiyear financial forecast." (emphasis added)[4] Thus, it is important for AE to continue to improve its liquidity position, including its Days Cash on Hand, in order to maintain its current rating, or improve to a 'AA' rating.

Non-Nuclear Decommissioning Study

A "Non-Nuclear Decommissioning Cost Study" was performed to determine reserve amounts that should be set aside for decommissioning AE's ownership share of the Fayette Power Project, Decker Creek Units 1 and 2, and Sand Hill Energy Center. The Decker Creek decommissioning cost is based on a site-specific engineering cost estimate, while Fayette Power Project and Sand Hill Energy Center decommissioning cost estimates were developed using a benchmark approach based on scaled costs from actual decommissioning costs for similar power plants and commission approved decommissioning cost data. A more detailed description of this study can be found in Section 10 of this report and Appendix 2.

Conclusions and Recommendations

In the conduct of our review, for each established reserve, NewGen evaluated the established intended purpose, 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. Our review took into consideration the practices and policies at peer Texas public power utilities, the applicable rules and standards at the Public Utility Commission of Texas ("PUCT") and the opinions of rating agencies (e.g., Fitch and Moody's). Additionally, the target level of funding for each individual reserve was evaluated to determine if the current target is appropriate or, alternatively, too high or too low to support its intended purpose(s). The reserves were also evaluated overall to test adherence to rating agency guidance on expected reserve levels for the credit rating desired by AE.

Based on this review, we conclude the following:

- Overall, current unrestricted reserves levels do not meet minimum funding requirements as stipulated in AE's current financial policies.
- Overall, current unrestricted reserve levels are too low to meet AE's credit rating objectives. Austin Energy desires to achieve and consistently maintain a 'AA' credit rating. However, AE is currently rated 'AA-' by Fitch and AE's Days Cash on Hand is well below the median Days Cash on Hand for similarly rated utilities. In order to maintain its current rating, AE is expected to improve its Days Cash on Hand to be more in alignment with its similarly rated peers.

[3] "U.S. Public Power Peer Study," Fitch Ratings, June 13, 2014.
[4] "Fitch Affirms Austin's (TX) Electric Utility Systems Revs at 'AA-'; Outlook Stable," April 23, 2015.

- The current reserve structure is confusing with overlapping purposes associated with several reserves.
- Other Texas public power utilities do not maintain the breadth of reserves that AE employs. Further, for reserves that are similar across utilities (e.g., working capital), the peer utilities do not often calculate their compliance in the same way as AE or use the same basis for appropriate funding levels.
- In certain cases, given the prescribed use of funds, reserve funding requirements are out of balance, with some reserves with too little funds and others with too much. Reserves that are underfunded include the Rate Stabilization, Non-Nuclear Decommissioning, Repair and Replacement and Contingency reserves. The Working Capital Reserve is over funded.

Given these conclusions, we recommend the following:

- Austin Energy's total unrestricted reserves, excluding the Non-Nuclear Decommissioning 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 reserves, 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:
  - Working Capital Reserve – The Working Capital Reserve should be funded consistent with PUCT guidelines, which exclude fuel and other power supply costs from the calculation. AE's internal calculation for this reserve is, thus, consistent with the PUCT guidelines. However, we recommend that reserves be greater than 45 days cash based on this formula. Days cash approaching 60 days considers firm obligations associated with City transfers, including both shared services and the General Fund Transfer. Austin Energy may reasonably target a greater number of days, but NewGen recommends that there be some maximum limit on this reserve (e.g., 90 days).
  - Strategic Reserve – NewGen recommends eliminating this overarching reserve category in lieu of specific reserves, as described below.
    - Emergency Reserve – We find the use and application of the Emergency Reserve to be duplicative with other reserve funds and, therefore, we recommend the elimination of this reserve.
    - Contingency Reserve – We recommend that the Contingency Reserve balance be maintained at a maximum of 60 days cash, 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 Cost. We recommend that any funds remaining from the Emergency Reserve, after fully funding the Contingency Reserve, should be deposited into the Rate Stabilization Reserve. Further, we recommend that the Rate Stabilization Reserve be funded going forward from net credit balances remaining in the Power Supply Adjustment ("PSA") over/under account balance upon periodic reevaluation of the PSA (typically annually), 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 Cost under-recoveries are funded from prior Net Power Supply Cost over-recoveries).

  AE could also consider funding the Rate Stabilization Reserve, when necessary, from an automatic surcharge attached to the PSA. Under this approach, meaningful deficiencies in the Rate Stabilization Reserve could be cured by an additional component within the PSA. However, this approach should be evaluated carefully before implementation to ensure it would endure a regulatory review, if initiated.

  Finally, we recommend that the Rate Stabilization Reserve maintain a cash balance between 90 and 120 days.

- Repair and Replacement Reserve – The Repair and Replacement Reserve is a critical reserve that insures AE has sufficient liquid resources to fund capital projects with equity. This reserve gives AE an important tool in managing the utility's equity contribution to capital projects, per existing financial policies. Therefore, we recommend that this reserve be renamed the Capital Reserve in recognition of its use to fund all capital projects. Further, we recommend that the Capital Reserve be funded at a minimum of 50 percent of the prior year's deprecation with no maximum amount identified. Without a maximum funding limit, NewGen recommends that additional cash reserves required to meet a 150 Days Cash on Hand goal be accrued in this reserve. Capital Reserve funds are available to be used on all AE approved capital projects and can be used to manage the debt to equity ratio of the utility over the long-run.
- Non-Nuclear Decommissioning Reserve – Austin Energy's financial policy requires that funds be set aside over a minimum of four years prior to closure to fund costs associated with expected plant closures. NewGen recommends that AE begin funding this reserve for the near-term need of retiring Decker Creek Units 1 and 2 promptly and to the fullest extent possible. NewGen recommends targeting the high end of the estimated range of costs for Decker decommissioning. As mentioned in the separate "Non-Nuclear Decommissioning Cost Study" report, there is good reason to believe the costs for AE will be at the higher, rather than lower, end of the range identified. Further, any funding beyond the needs of decommissioning the Decker Creek units can be applied to the next facility to be decommissioned.
- CIP Fund – No changes to the CIP Fund are recommended.

The recommended reserve funding criteria is summarized in Table ES-2.

Table ES-2
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 Cost	45 Days of O&M expense, less Net Power Supply Cost	60 Days of O&M expense, less Net Power Supply Cost (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 Cost	60 Days of O&M expense, less Net Power Supply Cost
Rate Stabilization	Reserve to mitigate unpredictable fluctuations in Net Power Supply Cost in order to stabilize rates and meet affordability goals	90 Days of Net Power Supply Cost	120 Days of Net Power Supply Cost
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.

For FY 2014, the application of NewGen's reserve recommendations compared to actual cash reserves and AE current financial policies is summarized in Table ES-3.

Table ES-3
Reserve Summary

	FY 2014 Actual	FY 2014 Per Financial Policies (1)	NewGen Recommendation (2) Basis	Low	High
Unrestricted Reserves (3)					
Working Capital	$ 150,799,894	$ 62,865,158	45 to 60 days(5), (6)	$ 62,865,158	$ 83,820,211
Emergency	80,765,286	83,820,211	Eliminated	0	0
Contingency	25,811,754	83,820,211	60 days(5)	83,820,211	83,820,211
Capital (4)	64,071	75,015,500	150 day goal(7)	145,318,827	83,136,939
Rate Stabilization	0	123,680,504	90 to 120 days(8)	123,680,504	164,907,339
Subtotal Unrestricted Reserves	$ 257,441,005	$ 429,201,583		$ 415,684,700	$ 415,684,700
Additional Reserves to Meet Credit Rating Goal of 150 Days Cash on Hand	$ 158,243,695	($ 13,516,883)		$ 0	$ 0
Subtotal Unrestricted Reserves with Credit Rating Goal	$ 415,684,700	$ 415,684,700		$ 415,684,700	$ 415,684,700
Non-Nuclear Decommissioning	8,138,072	8,138,072	Decker(9)	27,721,374	27,721,374
Total Reserves (10)	$ 423,822,772	$ 423,822,772		$ 443,406,074	$ 443,406,074

Notes:
1) Based on FY 2014 Actual, rather than Budget.
2) The Low and High listed do not refer to a low and high amount in reserve, as both columns reflect the same overall total reserves. Instead, this refers to using the low or the high basis for determining each reserve target.
3) Although AE considers some of the reserves listed to be restricted, the designation here signifies the rating agency treatment of these reserves.
4) Formerly the Repair and Replacement Reserve, per NewGen recommendations.
5) Based on days O&M, less Net Power Supply Cost.
6) AE may opt for a maximum greater than 60 days, but this would not change the overall total reserves (it would simply reduce the funding in the Capital Reserve) and, regardless, there should be some maximum associated with the Working Capital Reserve.
7) Based on a *minimum* of 50% of prior year's depreciation expense, but under NewGen's recommendations the cap on this reserve would be removed and any funding necessary for AE to attain 150 Days Cash on Hand would be deposited into this reserve, which is the basis for the amount shown.
8) Based on Net Power Supply Cost.
9) The high end estimate for decommissioning Decker Creek Units 1 and 2.
10) Excludes the CIP Fund, Bond Reserve, Debt Service Reserve and the externally managed Nuclear Decommissioning Trust, none of which are included in the Days Cash on Hand calculation.

As indicated in the table above, NewGen recommends that AE build reserves over time to achieve at least 150 Days Cash on Hand. For FY 2014, AE was short approximately $158 million in reserves in order to achieve this goal. If, however, each reserve had been funded at its target under the existing reserve fund policies, AE would have had in excess of 150 Days Cash on Hand (as indicated by the negative amount needed to achieve 150 Days Cash on Hand in the table).

Applying NewGen's reserve recommendations and funding criteria, additional reserves required to meet 150 Days Cash on Hand would be deposited into the Capital Reserve (previously the Repair and Replacement Reserve), which would have no maximum balance. Note that AE may opt for a maximum in the Working Capital Reserve greater than 60 days, but this would not change the overall total reserves (it would simply reduce the funding in the Capital Reserve). Further, whether it be 60 days or some other number, there should be some maximum associated with the Working Capital Reserve.

A more in-depth description of our analyses and additional recommendations can be found in Sections 6 through 11 of this report.

Section 1
INTRODUCTION

Reserve funds are an important financial risk management tool for a municipal utility. Reserves help utilities like Austin Energy ("AE") successfully manage unforeseen and significant fluctuations in operating and capital costs while maintaining stable, predictable rates. Seeking an independent perspective on the adequacy and use of AE's current reserves, AE retained NewGen Strategies and Solutions ("NewGen") to perform an assessment of AE's reserve funds, including a review of supporting financial policies. Specifically, NewGen has reviewed the purpose, use and funding of the Working Capital Reserve, the Strategic Reserve, the Repair and Replacement Reserve, and Non-Nuclear Decommissioning Reserve. Please note that the analysis related to the Non-Nuclear Decommissioning Reserve is provided in a separate report, "Non-Nuclear Decommissioning Cost Study," attached as Appendix 2.

This report identifies current fund balances to determine if targets are being achieved, discusses the rationale behind the various reserve funds, benchmarks AE's financial policies and reserves against other comparable utilities, and relays recommendations on required reserve funds and funding priorities. NewGen also surveyed Fitch and Moody's to determine the level of cash reserves these agencies consider adequate in the rating process.

This report summarizes the results of the reserve requirement study.

Section 2
EVALUATION METHOD

In the conduct of our analysis of AE's reserves, NewGen made the following investigations for each reserve:

- Established intended purpose(s) – NewGen reviewed financial policies that established each reserve, and other documents, to clearly establish the intended purpose or purposes.
- Evaluated compliance – NewGen evaluated each reserve's compliance with applicable financial policies.
- Confirmed calculation – NewGen confirmed and recreated the calculation determining the current, target, and/or maximum balance for each reserve.
- Reviewed historical use – NewGen reviewed the historical balance of each reserve as well as the sources of funding and uses of funds over time.
- Determined industry acceptance – NewGen determined the industry acceptance of each reserve. This included consideration of the practices and policies at peer Texas public power utilities and the applicable rules and standards at the Public Utility Commission of Texas ("PUCT" or "Commission"). The opinions of rating agencies (e.g., Fitch and Moody's) were evaluated to determine the applicability and support for the reserves.
- Assessed appropriateness – NewGen assessed the appropriateness of each reserve for AE as currently structured in order to develop recommendations for adjustments to each reserve, as appropriate. This included a review of the current method of calculating the balance for each reserve as well as the target and/or maximum balance and considering possible alternative calculations that might improve the nexus between the reserve and its intended purpose(s).

  Additionally, the target level of funding for each individual reserve was evaluated to determine if the current target is appropriate or, alternatively, too high or too low to support its intended purpose(s). This included risk analysis, where appropriate, to quantify AE's exposure to various risks based on the intended purpose(s) of the reserve. The reserves were also evaluated overall to test adherence to rating agency guidance on expected reserve levels for the credit rating desired by AE.

Based on these investigations, NewGen has developed specific recommendations for each of AE's reserves evaluated, including appropriate purposes and target funding levels.

Section 3
IMPORTANCE OF RESERVES

Municipally Owned Utilities ("MOUs") like AE are cash driven enterprises. To ensure financial stability over the long run, a MOU's primary concern is to have enough cash, after operating requirements, to meet debt service and infrastructure investment requirements. This financial objective is directly related to the ownership structure of a MOU and is very different from that of an Investor Owned Utility ("IOU"). IOUs are owned by stockholders and are concerned with maximizing their return on investment. When in need of cash, IOUs have access to equity and debt capital markets. By contrast, when MOUs need cash, only debt and cash reserves are options. As a result, it is very common for MOUs to establish financial policies that ensure adequate cash flow and cash reserves in order to successfully manage day-to-day business risk. Adequate cash flow is ensured by establishing rates on a "cash basis." Cash based rate making takes into consideration the cash needs of a utility, which typically includes operation and maintenance ("O&M") expense, debt service, capital paid from current earnings and the funding of reserves.

Types of Reserves

MOUs establish different types of reserves for different purposes. Reserves are generally either "restricted" or "unrestricted." Restricted reserves are limited in terms of what the funds may be used to pay for and are associated with a specific purpose. Restrictions are generally required and enforced by third parties or legal requirements. For example, a bond reserve is a common reserve with restricted use per the applicable bond ordinance. Cash set aside in such a reserve can only be used to retire debt. Unrestricted reserves are often more flexible and allow the utility to apply funds to a wider range of purposes within predefined limits. The use of unrestricted funds may be defined by utility policy, but the governing body can change or re-purpose its use of these funds, if necessary. Thus, although AE has reserves that it identifies as "restricted," such as the Strategic Reserve, these reserves may only be restricted by City of Austin ("City") designation, which could be changed by Austin City Council ("City Council"). As a result, from the perspective of rating agencies, only reserves that are restricted by external parties, such as restrictions by contract or regulation, are truly restricted. Thus, use of the terms "restricted" or "unrestricted" in this report are consistent with the rating agencies' view of the reserves. However, it is also common for funds dedicated or earmarked for a specific purpose, such as decommissioning or specific capital projects, to be excluded from some rating agency calculations, such as Days Cash on Hand.

Reserves can be further grouped as follows:

- **Working Capital** – Cash to ensure adequate resources to meet the day-to-day financial obligations of the utility associated with normal business operations.
- **Debt Service** – Cash set aside to meet future debt service payments.
- **Infrastructure** – Cash set aside to ensure adequate resources to meet planned new capital projects funded from cash.

- **Contingency** – Cash set aside for an emergency or other unusual events where, in total combined with third-party insurance, the utility has adequate financial resources to handle many low probability, but high risk, events.

Benefits

Cash reserves provide many benefits to MOUs and are a significant financial tool important to the financial health and viability of a utility. The benefits associated with reserves include:

- **Stable Rates** – MOUs can only access capital from rate revenues and borrowing. Often borrowing options are limited, only desirable within certain limits, time consuming and expensive. Reserves generated from rates in prior periods are an important financial resource available to a MOU to respond to fluctuating costs without incurring frequent rate adjustments. Reserves allow a MOU to administer rates in a measured and systematic manner while minimizing "rate shock."
- **Risk Management** – MOUs face many operating risks that may cause unforeseen stress on the utility's financial health, such as unexpected increases in expenses (or decreases in revenues) due to facility failures, weather events, changes in economic activity, etc. Often, this risk is managed financially through a combination of reserves, insurance and hedging. Reserves provide an important financial protection, as the funds are readily available at the discretion of the utility and its governing authority. Without reserves, and in the absence of immediate insurance funds, a utility could be faced with an immediate borrowing decision or an emergency increase in retail rates to address myriad common operating events.
- **Cost of Capital** – Reserves are an important consideration in evaluating the credit worthiness of MOUs. Rating agencies closely scrutinize liquid reserve levels. All things equal, MOUs with greater liquid reserves receive higher credit ratings. Higher credit ratings mean lower borrowing costs. For MOUs like AE, who regularly borrow from credit markets, lower borrowing costs can save ratepayers millions of dollars annually. As reported by FMSbonds, Inc. on June 17, 2015, the bond yield for an 'A' rated 20-year municipal bond was 3.70 percent compared to 3.35 percent for a 20-year 'AA' rated bond. The differential of 0.35 percent represents approximately $3,850,000 of annual interest expense on $1.1 billion of debt.

  Additionally, in ERCOT, higher rated utilities have expanded access to unsecured credit lines under ERCOT's credit standards than lower rated utilities.[5] This has a direct impact on the cost of operating in the ERCOT market.
- **Defensibility** – Reserves are funded from rate revenues and are an important consideration when determining a MOU's revenue requirement for ratemaking purposes. Well defined reserves improve the defensibility and justification for rate changes and are an important consideration in long-term financial planning. Each reserve fund should be established with a unique purpose, funding mechanism, and funding goal based on sound financial and regulatory criteria.

[5] As referenced in Section 16.11 of the Nodal Protocols

Costs

Cash reserves do have a cost, similar to any financial tool. Costs associated with reserves include:

- **Cost of Capital** – Liquid reserves are often in the form of cash or other short-term investment instruments. Compared to alternative financial investments and deployed capital, the return on liquid reserves is much lower than other alternatives. The cost of liquid reserves can be viewed as the lost opportunity associated with alternative investments achieving a greater return. However, these alternative investments could only be undertaken if sufficient replacement risk management tools were in place. These replacement tools come with direct and indirect costs and may not achieve any savings. Direct costs are associated with the cost of a financial alternative. Indirect costs may be associated with a lower credit rating due to lower liquidity on the balance sheet.
- **Rates not aligning with costs** – As mentioned above, one of the benefits associated with reserves is stable rates. However, to build and replenish reserves, from time-to-time, rates may be higher than costs. Critics of reserves often point out that rates are higher than they could be otherwise because reserves are too high or not needed. However, properly designed and funded reserves insulate customers from the costs associated with market volatility and high risk, unexpected events. Rate stability comes at a cost, which requires rates to be high enough to build and maintain reserves over time so that they function properly.

Alternatives

Cash reserves are a very common financial risk management tool used throughout the MOU industry. However, the amount of cash reserves may vary depending upon the following factors.

- **Insurance** – Many utilities self-insure a portion of their business operational risk. To the extent that self-insurance is an attractive lower cost option than other insurance options, cash reserve requirements often increase.
- **Short-Term Borrowing** – MOUs can enter into letter of credit and commercial paper instruments that provided quick and relatively easy access to capital markets. Usually, lending rates on letters of credit are greater than those achieved through traditional municipal revenue bond markets. Commercial paper borrowing rates are short-term and subject to frequent fluctuations. However, short-term borrowing rates have been very attractive in today's low interest rate environment. For AE, commercial paper borrowing is designed to fund the debt portion of capital projects. Once commercial paper borrowing reaches a certain limit (e.g., $200 million), AE converts the commercial paper into long-term debt. Austin Energy has the ability to use commercial paper to fund other assets, such as fuel and materials inventory within certain restrictions. Austin Energy may not use commercial paper funds for new nuclear or conventional coal generation units, per City policy. Austin Energy may not use commercial paper for O&M expenses.

  Unlike liquid cash reserves, these financial instruments are debt and may run counter to a utility's financial objectives that prescribe a lower leverage, higher equity balance sheet. If this is the case, then these options are less attractive as borrowed funds may limit a MOUs overall system financing options. Also, principle and associated interest must be paid by cash generated from rates in a relatively short period of time, thus providing less of a buffer to unwanted fluctuations in rates.

- **Equity** – IOU's frequently use equity markets as a source of capital. MOUs do not have access to these markets and use cash reserves in its place. From this perspective, cash reserves can be viewed as equity contributed by customers over time.

Administration

Effective reserves are well designed, actively managed, and routinely reported to stakeholders. Key elements associated with these attributes include the following guidelines:

1. Establish reserves with a clear purpose, funding mechanism, and use of funds.
2. Establish reserves such that they support a utility's financial policies and objectives. For AE, important objectives include the following (to be discussed later):
   a. Debt to Equity Ratio
   b. 'AA' Credit Rating
   c. Two percent annual affordability goal for rates
3. Specify minimum and maximum funding parameters, where appropriate.
4. Actively manage reserves so that funding parameters are met. When funds become "out-of-bounds," specify the timeframe allowed to return to compliance.

Section 4
IMPACT ON RATES

A primary concern of a MOU is cash flow. MOUs must generate enough cash to meet day-to-day expenses, including cash capital needs, as well as debt service obligations. As a result, AE and most other MOUs establish a revenue requirement on a cash basis (as opposed to a utility basis, which is most common for IOUs). A revenue requirement is a calculation that determines the overall level of rate revenues for the system. A cash basis approach identifies all the cash obligations of the utility that must be included in the revenue requirement.

On October 1, 2012, AE implemented retail rates as a result of a comprehensive rate study that represented a detailed and in-depth review of AE costs, customer classes, and rate structures (the "2011 Rate Study"). In its 2011 Rate Study, AE's revenue requirement included the general components listed in Table 4-1.

Table 4-1
Components of AE's Revenue Requirement

Revenue Requirement Component	Treatment
Operation and Maintenance Expense, excluding Depreciation	Add
Depreciation	Non-cash item that nets to zero
Debt Service	Add
General Fund Transfer	Add
Other Expenses	Add
Capital Funding from Current Earnings	Add
Reserve Contributions	Add or subtract
Non-Rate Revenues	Subtract
Interest Income	Subtract
Total Revenue Requirement	Sum of above

Reserve funding requirements impact the revenue requirement to the extent that current reserve balances are being increased or depleted. For example, in the 2011 Rate Study, reserve deficiencies were identified that resulted in an approximately $30 million increase in the revenue requirement. Conversely, to the extent that reserves may be greater than required, they can be reduced gradually over time and lower the revenue requirement.

Because reserves either increase or decrease the overall revenue requirement, they are subject to the scrutiny of stakeholders engaged in the ratemaking process. Therefore, as previously mentioned in Section 3, it is important that reserves are well defined with a clear purpose and supportable funding levels.

Similarly, because reserves either increase or decrease the overall revenue requirement, reserves stabilize rates and essentially improve the predictability of rates over time. Given AE's rate affordability goals, which apply to the total rate, adequate reserves are a critical tool to successfully manage volatile costs while keeping rates at, or below, the affordability goals.

Section 5
OVERVIEW OF CURRENT FINANCIAL POLICIES AND RESERVES

AE Financial Goals

On June 15, 1989, City Council developed financial policies per Ordinance No. 890615-E to ensure that City financial resources are managed prudently. These policies are reviewed annually for compliance. Changes to the policies are proposed for City Council consideration on an as needed basis.

Austin Energy's principal financial goals include maintaining a 2.0 debt service coverage ratio, sufficiently funding reserves, maintaining a reasonable level of cash for operations and debt service, adequately funding for capital projects through a combination of debt and equity, management of short-term and long-term debt, and providing transfers to the City's general fund.

Also, these financial policies assist the City and AE to achieve and maintain strong credit ratings as they include financial metrics recommended by the major rating agencies and, additionally, include the covenants specified in the utility's bond indentures. Comprehensive and sound financial policies that are actively administered and adhered to result in a financially healthy and strong utility. Such a utility enjoys the financial flexibility to manage uncertain future events and benefits from favorable borrowing terms and lower interest rates, which, in turn, keeps customer rates lower. Entities in weak financial condition have less financial flexibility, which limits the utility's access to capital and requires the utility to borrow at higher costs.

AE's financial policies can be categorized into the following groups:

- Debt Management
- Capital Projects and Routine Maintenance
- Flow of Funds and Transfers
- General Fund Transfer
- Liquidity and Reserves
- Decommissioning

Debt Management

AE issues debt to fund a portion of its capital projects, which include generation projects, transmission and distribution projects, on-site generation projects, alternative energy projects, and support services projects. Austin Energy's financial policies related to debt management provide direction on the issuance of debt by the utility and were crafted to ensure that AE maintains a strong credit rating.

The policies relevant to debt management are summarized below. However, a detailed listing of all AE's financial policies are included in Appendix 1.

- **Policy No. 1 - Debt Term:** This financial policy was shaped to meet bond covenant requirements, and states that, "the term of debt generally shall not exceed the useful life of the asset, and in no case shall the term exceed 30 years."
- **Policy No. 2 - Capitalized Interest Cost**: This policy addresses the guidelines for the use of capitalized interest, which shall only be considered during the construction phase of a new facility, if the construction period exceeds seven years. The timeframe for capitalizing interest may be three years but not more than five years. The capitalized interest guideline was followed during the construction of the South Texas Nuclear Project, but has not been used in recent years and, due to the application of regulatory accounting; AE will no longer capitalize interest.
- **Policy No. 3 - Principal Repayment Delays**: AE permits delays in principal repayments between one to three years, but no more than five years.
- **Policy No. 4 - Bond Insurance Policies:** This policy was established to meet the Combined Utility Systems Revenue Bond Covenant requirements and states that AE either, "maintain bond insurance policies or surety bonds by highly rated ('AAA') bond insurance companies or fund a debt service reserve, or a combination of both for its existing revenue bond issuance." As of Fiscal Year ("FY") 2010, no 'AAA' rated bond insurance companies were in existence and AE established a debt service reserve.
- **Policy No. 5 - Debt Service Reserve:** This policy outlines the conditions related to the requirement of a debt service reserve as specified in the bond ordinance. Austin Energy is required to maintain a debt service reserve if system pledged net revenues, after deducting annual debt service for Prior First Lien and Prior Subordinate Lien bonds, are less than 1.5x annual debt service requirements on the separate lien obligations.

  Policy No. 6 - Debt Service Coverage: AE is required to maintain a minimum of 2.0 times ("x") debt service coverage for its existing bonds. Debt service coverage is the amount of net cash flow available to meet annual principal and interest payments on debt. Although this policy sets a minimum requirement for compliance at 2.0x, AE's bond covenants require it to maintain a 1.5x debt service coverage. The purpose of requiring a coverage level higher than 1.5x is to provide a safety margin to be able to manage AE's business risk and ensure debt service payments will be paid timely.

  It is important to note that, per Financial Policy No. 17, AE sets rates based on a cash flow basis. As described in Section 4, components of AE's revenue requirement include, O&M (excluding depreciation), debt service, general fund transfers, other expenses, capital funding from current earnings, reserve contributions, less non-rate revenues and interest income. Given AE's current leverage, it is expected that the debt service coverage ratio would exceed the 2.0x requirement and, therefore, the 2.0x requirement does not drive utility rate levels. Thus, although rates must achieve a minimum of 2.0x debt service coverage to be in compliance with Financial Policy No. 6, this is a secondary check, rather than the primary driver of the revenue requirement or rates.

  The debt service coverage ratio is a critical financial metric in determining credit ratings.
- **Policy No. 7 - Short-Term Debt:** Short-term debt requirements maintain a maximum term of five years and maximum limit of 20 percent of outstanding long-term debt. Austin Energy issues commercial paper to provide initial financing for its capital improvement

projects due to its lower interest rates as compared with long-term debt. By minimizing interest payments, AE is able to keep overall costs lower for ratepayers.

- **Policy No. 8 - Commercial Paper:** AE addresses the use of commercial paper and its conversion to long-term refunding bonds in this policy and, additionally, states that, "commercial paper may be used to finance capital improvements required for normal business operation from Electric System additions, extension, and improvements." This, however, does not apply to new nuclear or conventional coal generation units.

  The City maintains a Tax-Exempt Commercial Paper Program for the Combined Utility Systems (AE and Austin Water) in an amount that may not exceed $400 million and a Taxable Commercial Paper Program for AE that may not exceed $50 million.

Capital Projects and Routine Maintenance

These policies provide guidelines for the cash (i.e., "pay-as-you-go") funding for ongoing routine and preventative maintenance. Austin Energy also targets an equity contribution ratio between 35 percent and 60 percent for capital projects. Further, per City Ordinance 20120607-055, the long-term target for capital structure equity contribution is 50 percent.

- **Policy No. 9 – Routine Maintenance:** Austin Energy requires that ongoing routine and preventative maintenance should be funded on a pay-as-you-go basis. To clarify, cash generated revenues from operations should be used to pay for ongoing routine and preventative maintenance, as opposed to using debt. The utilization of debt is specifically reserved for funding the construction of projects with longer useful lives.

- **Policy No. 14 – Equity Contribution Ratio**: This policy limits overall debt financing levels by requiring capital projects to be financed with a combination of debt and cash. Austin Energy targets an equity contribution ratio between 35 percent and 60 percent. Higher equity contributions indicate a lower financial risk to the utility, thereby minimizing the utility's fixed payments and lowering the overall cost of debt. A lower debt contribution ratio additionally minimizes rates charged to the customer, as rates must recover debt service requirements. A higher equity contribution ratio is viewed favorably by the rating agencies.

Flow of Funds and Transfers

These policies indicate how net revenue generated by AE will be dispersed across AE's funds. Austin Energy identifies the flow of funds, specifically in what order net revenues will be allocated to provide for operations, debt service, general fund transfers, cash funding of capital improvement projects, and other bond covenant requirements (e.g., debt service reserve). The bond covenants may also prescribe the flow of funds in rate setting.

- **Policy No. 12 - Net Revenue Allocation:** According to this policy, net revenue generated by AE, shall be used for General Fund Transfers, capital investment, repair and replacement, debt management, competitive strategies, and other AE requirements, such as working capital.

- **Policy No. 17 - Flow of Funds:** This policy identifies the flow of funds, that is, the order in which net revenues are allocated to the various AE funds. Net revenues will cover the following items, in order of priority: (1) operations (including depreciation), (2) debt service, (3) General Fund Transfer, (4) equity funding of capital investments, (5) requisite deposits of all reserve amounts, (6) sufficient annual debt service requirements of the Parity Electric Utility Obligations and other bond covenant requirements, and (7) if applicable, any other current obligations.

General Fund Transfer

The General Fund Transfer is an annual transfer from AE to the City's General Fund. Austin Energy's General Fund Transfer policy is based on the percentage of gross revenue method, which is a common approach used by public power utilities.

- **Policy No. 13 - General Fund Transfer:** The General Fund Transfer shall not exceed 12 percent of AE's three-year average revenues, which are calculated using the current year estimate and the previous two years' actual revenues. Per City Council direction, this calculation excludes revenue associated with Net Power Supply Cost and on-site energy resources. Also per City Council direction, the General Fund Transfer has a minimum of $105 million per year.

Liquidity and Reserves

The policies related to liquidity and reserves were established to ensure that adequate liquidity is available for daily operations of the utility, in addition to providing funding for unforeseen events. Reserves represent a significant financial resource and an effective tool that improves AE's financial flexibility in the event that any unanticipated events occur, such as revenue shortfalls, net power cost spikes resulting from unplanned generation outages, outage expenses, financial market disruption, competitive pressures, or a requirement to cash fund a debt service reserve to remedy default on a bond covenant.

For each reserve, the procedures and approvals required to allow access to (or use of) the funds lies with City Council and the Approved or Amended Budget. Austin Energy must budget for any additions to or transfers out of each reserve by showing movements from the AE operating reserve to/from the specialized, individual reserve funds. The normal process is to propose the movement to/from these reserves during the normal City budget process, which starts in January of each year and culminates with City Council approval in September. Any budget changes approved during the process can be accessed at any time during the fiscal year in which they were approved by contacting the City's financial services Treasury Department, who is responsible for moving the funds from the financial market to AE's operating budget for use. If funds are requested to be accessed during the fiscal year and have not been previously approved by City Council in the budget, a budget amendment must be prepared for City Council approval, which includes a fiscal note showing the movement of the funds from the operating reserve to the individual reserve, or vice versa.

The original policy that set Working Capital Reserve requirements at 45 days was established in 1989, and the policies establishing the original Debt Management Reserve and the Repair and Replacement Reserve were approved during the FY 2002 approved budget process. The Non-Nuclear Decommissioning Reserve was established during the FY 2004 approved budget process. The policies that assess financial strength were issued to identify minimum financial and operational guidelines. This is a necessary step to ensure that the desired bond rating for the utility is achieved.

Reserve policies are also used to improve the competitive position of the electric utility, and rating agencies recognize these policies as a mitigating factor for increased utility risk. Please note the reserve policies identified below are reiterated and explained in greater detail in the subsequent sections of this report.

- **Policy No. 11 - Working Capital Reserve:** This financial policy establishes the working capital, or operating cash, reserve that is intended to meet normal day-to-day operation and maintenance expenses, less fuel.[6] Per this policy, AE must maintain 45 days of budgeted O&M, less pass-through costs related to net power supply ("Net Power Supply Cost").[7]
- **Policy No. 10 - Quick Ratio:** Per this policy, AE is required to maintain a quick ratio of 1.50. The quick ratio measures a utility's ability to meet its short-term obligations with its most liquid assets, which excludes inventories. The higher the ratio, the more liquid the current position.
- **Policy No. 19 - Parity Electric System Obligations:** Austin Energy is required to maintain a minimum balance equal to debt service on its outstanding separate lien bonds.
- **Policy No. 15 - Repair and Replacement Reserve:** The Repair and Replacement Reserve has a targeted balance no greater than 50 percent of the prior year's depreciation expense. This reserve is used for extensions, additions, replacement of aging infrastructure, and improvements to the electric system.
- **Policy No. 16 - Strategic Reserve Fund:** The Strategic Reserve provides funds to offset revenue or expense fluctuations due to natural disasters or unplanned economic stress. The Strategic Reserve is currently comprised of the following components:
    - Contingency Reserve: Funds in this reserve shall not exceed a maximum of 60 days of O&M expense, less Net Power Supply Cost. This reserve is used for unanticipated or unforeseen events that reduce revenue or increase obligations, such as extended unplanned plant outages, insurance deductibles, unexpected costs created by Federal or State legislation, and liquidity support for unexpected changes in fuel costs or purchased power that stabilizes fuel rates for AE customers.
    - Emergency Reserve: The Emergency Reserve must have a minimum of 60 days of O&M expense, less Net Power Supply Cost. This reserve is only used as a last resort after the Contingency Reserve has been exhausted to provide funding in the event of an unanticipated or unforeseen extraordinary need of an emergency nature.
    - Rate Stabilization Reserve: The purpose of the Rate Stabilization Reserve is to stabilize utility rates in future periods.
- **Policy No. 20 - Revenue Requirements**: Austin Energy is required to have current revenues, which do not include the beginning balance, which are sufficient to support current expenditures. This policy is necessary as it sets "structural balance" as a standard for budgeting.

In FY 2014, total unrestricted reserve levels were $265,579,077, excluding the CIP Fund, as summarized in Table 5-1.

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[6] The financial policy as written references fuel, but this also includes all Net Power Supply Cost.
[7] Net Power Supply, as used in this report, includes the cost of fuel, power purchase agreements, net ERCOT revenue, green choice costs not billed to customers directly, regulatory charges associated with the Fuel Adjustment Clause, and the hedging program.

Table 5-1
Unrestricted Reserves

	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual
Working Capital	$ 48,668,471	$ 119,230,805	$ 150,799,894
Strategic Reserve			
Emergency	69,484,824	80,508,399	80,765,286
Contingency	68,122,357	25,487,620	25,811,754
Rate Stabilization	-	-	-
Repair & Replacement	64,071	64,071	64,071
Non-Nuclear Decommissioning	15,093,817	11,490,144	8,138,072
Total (1)	$ 201,433,540	$ 236,781,039	$ 265,579,077

Notes:
1) Excludes the CIP Fund, Bond Reserve, Debt Service Reserve and the externally managed Nuclear Decommissioning Trust.

Decommissioning

These policies outline the requirements for establishing and funding nuclear and non-nuclear decommissioning reserves.

- **Policy No. 18 - Nuclear Decommissioning Trust:** Austin Energy began collecting in rates, and accumulating funds in a trust, to decommission the South Texas Nuclear Project pursuant to Federal regulations. The Nuclear Decommissioning Trust is a restricted account that is held by an independent trustee.
- **Policy No. 21 - Non-Nuclear Decommissioning Reserve:** The Non-Nuclear Decommissioning Reserve was established to ensure that adequate funding is available to decommission non-nuclear power plants.

Credit Rating Goal

Although not explicitly identified in financial policies, AE has had in place for many years a financial goal to achieve and maintain a 'AA' credit rating. The first reference to this goal appears in AE's 2003 Strategic Plan. In the 2015 budget, under AE's Mission and Goals for 2015, the utility states the following goal:

> Maintain strong financial position in support of the Utility's Risk Management strategy and achieve improved credit ratings as measured by bond ratings agencies. Achieve the 'AA' credit rating on separate lien electric utility system revenue bonds on the Standard & Poor's rating.

However, AE is currently rated 'AA-' by Fitch and the median Days Cash on Hand for similarly rated utilities by Fitch is 180 days, which is well in excess of AE's current level of Days Cash on Hand.[8] Ratings are the result of many factors, and simply attaining (or not attaining) 180 Days Cash on Hand is not, in of itself, cause to upgrade (or downgrade) a utility's rating. In AE's

[8] "U.S. Public Power Peer Study," Fitch Ratings, June 13, 2014.

case, there are other factors, such as its relatively low leverage, that have facilitated its 'AA-' rating. However, in order to maintain its current rating, AE is expected to improve its Days Cash on Hand to be more in alignment with its similarly rated peers. In its April 2015 publication, Fitch stated, "Liquidity and cash flow metrics remain somewhat low relative to rating category medians, but additional improvement ***is expected*** based on AE's multiyear financial forecast." (emphasis added)[9] Thus, it is important for AE to continue to improve its liquidity position, including its Days Cash on Hand, in order to maintain its current rating, or improve to a 'AA' rating.

[9] "Fitch Affirms Austin's (TX) Electric Utility Systems Revs at 'AA-'; Outlook Stable," April 23, 2015.

Section 6
WORKING CAPITAL RESERVE

The Working Capital Reserve[10] (also sometimes referred to as the operating reserve or operating cash) is intended to provide AE funds to accommodate the utility's day-to-day operating cash needs and provide financial flexibility to endure variations in revenue and non-Power Supply expenses during the course of normal operations. The Working Capital Reserve is intended to act as a financial cushion to aid AE in meeting fluctuations in costs that are not recovered via the Power Supply Adjustment ("PSA").

A working capital reserve is a common, necessary fund that exists in one form or another at all utilities, not just electric utilities. A working capital reserve is similar to a business or personal checking account and is critical to AE in meeting day-to-day O&M costs. This fact is recognized by the PUCT, which allows for the inclusion of cash working capital in the development of regulatory rate base.[11] The appropriate level of working capital may be determined by policy (e.g., 45 to 150 days reserve) or the conduct of an analysis, such as a lead-lag study, to examine the utility's cash conversion cycle.[12]

The Working Capital Reserve requirement is calculated by AE annually during the budget and forecast process, and the actual Working Capital Reserve balance is calculated quarterly. The balance can increase or decrease based on normal fluctuations in utility business operations or be replenished or depleted via transfers from/to other reserves. For example, in FY 2012 and FY 2013, AE had to withdraw funds from the Strategic Reserve in order to support day-to-day operations and funds from the Strategic Reserve were transferred into the Working Capital Reserve. There is no policy for replenishing the Working Capital Reserve if it falls below the required amount, but this should be done as quickly as possible, as these funds are critical to the operation of the utility and balances below the 45-day target could impact AE's financial sustainability.

The Working Capital Reserve balance history for AE is shown in Table 6-1. From FY 2010 to FY 2012 the Working Capital Reserve balance declined significantly (by 64 percent) as the utility was under-recovering from rates and was in the process of conducting a rate study to align its rates with its cost of service. Transfers from the Strategic Reserve[13] as well as new rates effective October 1, 2012 began to replenish the Working Capital Reserve between FY 2012 and FY 2014 and the balance rebounded. Over there period FY 2010 to FY 2014, the Working

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[10] Although not technically a reserve, as it is simply the cash available to facilitate day-to-day operations, we have labeled this the Working Capital Reserve for consistency within the report.

[11] Rate base is the value of property and investments on which a utility is permitted to earn a rate of return, in accordance with rules set by a regulatory agency.

[12] A lead-lag study determines the differences in timeframe between (1) the time services are rendered until the revenues for those services are received; and (2) the time that the costs associated with items used in providing those services, such as labor and materials, are incurred until they are paid for by the utility. The difference between these periods is expressed in days, which is then multiplied by the average daily operating expenses to identify the working capital required for operations.

[13] Transfers from the Strategic Reserve to the Working Capital Reserve totaled $24,750,000 in FY 2012 and $10,900,000 in FY 2013.

Capital Reserve balances fluctuated by over $100 million, or approximately 25 to 30 percent of AE's annual O&M expense, less Net Power Supply Cost.

Table 6-1
Working Capital Reserve Balance

	FY 2010 Audited	FY 2011 Audited	FY 2012 Audited	FY 2013 Audited	FY 2014 Audited
Working Capital Reserve	$ 133,593,652	$ 70,768,039	$ 48,668,471	$ 119,230,805	$ 150,799,894

Financial Policy No. 11 – Working Capital Reserve

The Working Capital Reserve has a target of 45 days of budgeted O&M expense, less Net Power Supply Cost. This target was established in Financial Policy No. 11. NewGen views this target as a minimum. Many public power utilities operate with significantly higher balances in their working capital reserve but, in some cases, this is because the utility does not maintain other financial reserves (like the ones established for AE). Further, ratings agencies, in order to obtain favorable credit ratings, require electric utilities to carry significantly higher balances of liquid cash on hand than 45 days would represent. However, when calculating liquid cash on hand for AE, the rating agencies include balances in other non-restricted reserves, such as the Strategic Reserve.

As an additional point of reference, AE's 45 day target for the Working Capital Reserve is consistent with the "1/8th Rule" routinely adopted in PUCT rate case proceedings, including regulated electric transmission filings. The 1/8th Rule implies a reserve balance equal to one-eighth of a year's costs, which is approximately equal to 45 days. The PUCT also excludes fuel and purchase power costs (as well as materials, supplies, prepaid expenses, and depreciation) when applying the 1/8th Rule.[14] It should be noted that these regulations do not necessarily apply to AE, as a MOU, but following these rules makes AE consistent with IOU regulations. Further, the 1/8th Rule should not be viewed as a limit (or maximum) on appropriate working capital. A utility may make a case for an amount greater than the 1/8th Rule would imply when filing at the PUCT. Working capital requirements will vary from utility to utility in consideration of a variety of factors, including ownership of generation assets, wholesale market design, retail rate structure, debt/equity ratio, access and availability of other liquid reserves, etc. Taking all these factors into consideration may justify minimum liquid reserve requirements in excess of 45 days.

The relevant O&M costs, less Net Power Supply Cost, for FY 2012 through FY 2014 are shown in Table 6-2 along with a calculation of the number of days Working Capital for these years. The calculation takes the average daily non-Power Supply costs and divides this value into the average Working Capital Reserve balance to determine days of working capital. As shown in the table, AE is in compliance with the 45-day requirement.

[14] P.U.C. SUBST. R. 25.231(c)(2)(B)(iii)

Table 6-2
Days Working Capital Calculation

	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual
Working Capital Reserve Beginning of Year Balance (1)	$ 70,768,039	$ 48,668,471	$ 119,230,805
Working Capital Reserve End of Year Balance	48,668,471	119,230,805	150,799,894
Average Working Capital Reserve Balance	$ 59,718,255	$ 83,949,638	$ 135,015,350
Net Power Supply Cost	$ 425,895,800	$ 453,813,794	$ 501,593,156
Non-Power Supply Cost	401,163,047	460,356,283	509,906,281
Total O&M Cost	$ 827,058,847	$ 914,170,077	$ 1,011,499,437
Average Daily Non-Power Supply Cost (2)	$ 1,099,077	$ 1,261,250	$ 1,397,004
Days Working Capital Reserve (3)	54	67	97

Notes:
1) The fiscal year beginning balance is equal to the preceding year ending balance.
2) Annual Non-Power Supply Cost divided by 365 days.
3) Average Working Capital Reserve Balance divided by the Average Daily Non-Power Supply Cost.

Transfers to the City

The way AE currently calculates days working capital does not consider transfers to the City. However, increasingly rating agencies are viewing these transfers as just as firm an obligation as O&M and are, correspondingly, beginning to consider these transfers in their evaluations. This reflects the fact that these transfers are not optional costs for the utility. Some pubic power utilities are recognizing this trend and including transfers as an “above the line” expense when setting financial policies.

If AE were to revise its policy for days working capital to account for transfers to the City, it would increase the amount needed to be in compliance with the policy. This is demonstrated in Table 6-3.

Table 6-3
Days Working Capital Calculation

	Current Calculation	With Admin Transfers	With Admin and GFT
FY 2015 Proposed Non-Power Supply O&M	$ 552,009,009	$ 552,009,009	$ 552,009,009
FY 2015 Proposed Administration Transfers (1)			
Voluntary Utility Assistance Fund		$ 600,000	$ 600,000
Trunked Radio		282,961	282,961
Workers' Compensation		2,338,903	2,338,903
Administrative Support		20,132,282	20,132,282
Communication & Technology		5,985,656	5,985,656
Economic Development Fund		8,388,453	8,388,453
Total Administration Transfers		$ 37,728,255	$ 37,728,255
FY 2015 Proposed General Fund Transfer ("GFT")			$ 105,000,000
Total Costs Considered	$ 552,009,009	$ 589,737,264	$ 694,737,264
Working Capital Balance Needed for 45 Day Compliance (2)	$ 68,055,905	$ 72,707,334	$ 85,652,539

Notes:
1) Excludes reserves and capital improvement program transfers.
2) Total Costs Considered divided by 365 days times 45 days.

NewGen recommends AE revise its policy to cap the amount of funds included in the Working Capital Reserve to either:

1. 45 days of O&M expense, less Net Power Supply Cost, plus all required transfers to the City, including the General Fund Transfer. This would recognize AE's firm financial obligation associated with these transfers, which are similar in nature to other non-recoverable O&M expenses. Also, this treatment recognizes the rating agency trend of viewing these costs as "above the line," similar to O&M costs, rather than "below the line."

   OR

2. 60 days of O&M expense, less Net Power Supply Cost. If AE wanted to account for the City transfers without changing its calculation methodology, it could simply increase the number of days required under the policy in recognition of these expenses. For example, in order to account for all the transfers to the City as proposed in FY 2015, including the General Fund Transfer, AE's policy on the number of days working capital would have to increase to 60 days from 45 days. Although this would still be consistent

with public power norms, as discussed later, this would cause AE's policy to deviate from the 1/8th Rule prevalent at the PUCT.

Austin Energy may reasonably target a greater number of days, but NewGen recommends that there be some maximum limit on this reserve (e.g., 90 days). NewGen believes that placing a cap on this reserve is important as any regulatory review of the Working Capital Reserve balance would be grounded on the 1/8th Rule. We recommend any additional funds, that would be in excess of the cap, be accrued in the Repair and Replacement Reserve (or its successor) as needed to achieve AE's credit rating goal, as described later in this report.

Financial Policy No. 10 – Quick Ratio

Financial Policy No. 10 also has some relation to the Working Capital Reserve as it requires that AE maintain a quick ratio of at least 1.50. The quick ratio is a common measure of the utility's ability to meet its short-term obligations with its most liquid assets. A higher ratio indicates a more liquid (and stronger) current financial position.

The quick ratio formula is (Current Assets – Inventory)/Current Liabilities. Since the quick ratio is based on all current assets (not just the Working Capital Reserve) it is not a direct measure of the reserve, but the Working Capital Reserve is a meaningful component of the current assets (as identified in Table 6-3). Other current assets include balances in other reserves, such as the Strategic Reserve, as well as accounts receivable, inventories, regulatory assets, prepaid expenses, etcetera. Thus, the Working Capital Reserve is a critical contributor to AE satisfying the quick ratio and the quick ratio is instructive as to AE's financial condition in the view of rating agencies and creditors.

Table 6-4 illustrates the calculation of the quick ratio based on data for AE in the City's comprehensive annual financial report ("CAFR"). As illustrated in the table, AE is in compliance with the 1.50 requirement.

Table 6-4
Quick Ratio Calculation

	FY 2012 Actual	FY 2013 Actual	FY 2014 Actual
Current Assets (1)			
Cash + Pooled (Working Capital)	$ 48,669,000	$ 119,231,000	$ 150,800,000
Pooled (restricted)	81,100,000	90,888,000	103,607,000
Other (2)	436,441,000	396,599,000	383,501,000
Total Current Assets	$ 566,210,000	$ 606,718,000	$ 637,908,000
Less Inventory (1)	(80,965,000)	(84,386,000)	(74,429,000)
Net Current Assets	$ 485,245,000	$ 522,332,000	$ 563,479,000
Current Liabilities (1)	$ 258,915,000	$ 228,005,000	$ 201,725,000
Quick Ratio	1.87	2.29	2.79

Notes:
1) Data in the CAFR is shown in thousands of dollars.
2) Other current assets include accounts receivable, inventories, regulatory assets, prepaid expenses, and etcetera.

Similar to information shown in Table 6-2, increases in the Working Capital Reserve balance improve the quick ratio results.

Financial Policy No. 19 – Debt Service

Austin Energy has three types of revenue bonds outstanding – prior lien, subordinate lien and separate lien. The prior lien and subordinate lien bonds were issued prior to 2001 and represent combined utility obligations of the electric, water and wastewater utilities. Since 2001, AE has issued separate lien revenue bonds, which are secured only by AE's electric utility revenue. The separate lien revenue bonds are also referred to as the Parity Electric System Obligations.

The master ordinance of the Parity Electric System Obligations does not require a debt service reserve fund. However, per Financial Policy No. 19, AE will maintain a minimum of unrestricted cash on hand equal to six (6) months debt service for the outstanding separate lien bonds. Table 6-5 lists the semiannual payments due on revenue bonds for November 2013 through May 2016.

Table 6-5
Revenue Bond Debt Service

	Nov 2013	May 2014	Nov 2014	May 2015	Nov 2015	May 2016
Debt Service (1)						
Prior Lien	$ 312,500	$ 0	$ 3,344,094	$ 0	$ 3,344,094	$ 0
Subordinate Lien	2,564,078	4,787,096	2,505,724	4,895,746	2,442,986	13,955,174
Separate Lien	86,383,803	49,204,840	69,107,340	27,068,378	80,574,577	27,414,195
Total Debt Service	$ 89,260,380	$ 53,991,936	$ 74,957,158	$ 31,964,124	$ 86,361,657	$ 41,369,369

Notes:
1) Interest on revenue bonds is paid semiannually on May 15 and November 15, while principal is paid annually on November 15.

Financial Policy No. 19 only requires that the cash on hand be unrestricted, not that it must be in the Working Capital Reserve. However, the Working Capital Reserve represents a significant portion of AE's unrestricted cash and debt service is a base, non-Power Supply cost, so it is a relevant test to make sure the Working Capital Reserve is sufficient to satisfy six months of separate lien debt service.

Although perhaps not required by the financial policy, NewGen recommends the maximum debt service payment over the prospective year be used as the relevant basis for testing the sufficiency of funds in the Working Capital Reserve. This represents the "worst case scenario" in terms of possible debt requirements over the subsequent year.

Comparing the recent Working Capital Reserve balance in Table 6-1 with the separate lien debt service shown in Table 6-5, demonstrates that the Working Capital Reserve alone is sufficient to satisfy Financial Policy No. 19, even under NewGen's more conservative interpretation of the policy (i.e., maximum debt service payment over the prospective year versus six months debt service). This is summarized in Table 6-6.

Table 6-6
Working Capital Reserve Compared with Debt Service

	Source	FY 2014	FY 2015
Working Capital Reserve Fiscal Year Beginning Balance (1)	Table 6-1	$ 119,230,805	$ 150,799,894
Prospective Maximum Debt Service Payment on Separate Lien Debt (2)	Table 6-5	86,383,803	69,107,340
Excess/(Deficit)		$ 32,847,002	$ 81,692,554

Notes:
1) The fiscal year beginning balance is equal to the preceding year ending balance.
2) The maximum debt service payment over the next year from the perspective of October 1 (the beginning of the fiscal year) would be the November payment. Only the separate lien bonds are related to Financial Policy No. 19.

It is important to note that AE may also consider other reserves, such as the Strategic Reserve, to satisfy Financial Policy No. 19. This was important in FY 2012, when the Working Capital Reserve balance was at a recent low.

Benchmarking

NewGen conducted a benchmarking analysis with regards to utility reserve funds for the following Texas public power entities: CPS Energy of San Antonio ("CPS"), Garland Power and Light ("GP&L"), Brownsville Public Utilities Board ("Brownsville PUB"), Lubbock Power and Light ("LP&L"), and Bryan Texas Utilities ("BTU"). Each public power utility surveyed had a working capital reserve in one form or another, as this fund is instrumental in facilitating the cash operations of the utility. However, there was variation in the structure of the reserves and in their requirements. Further, some utilities do not have a formal policy on working capital reserves set by a governing body. The benchmarking results are discussed below.

- CPS has a working capital reserve and a repair and replacement reserve and the sum of these two reserves should be sufficient to meet their 150 Days Cash on Hand goal, per their own internal policy.
- GP&L has a 45-day cash working capital policy in addition to a rate mitigation fund for which there is no formal target. GP&L's internal policy is to have at least 75 Days Cash on Hand overall.
- Brownsville PUB is required to retain a reserve amount to pay operating and maintenance expenses of not less than two months (i.e., 60 days) of budgeted operating and maintenance expenses for the current fiscal year.
- LP&L's policy is to maintain sufficient operating cash to satisfy all current accounts payable and maintain a general reserve fund that is equal to or greater than three months (i.e., 90 days) gross retail revenue as determined by taking the average monthly gross retail revenue from the previous fiscal year. The general reserve fund shall be used for operational purposes, rate stabilization, and for meeting the electric utility demand of any rapid or unforeseen increase in residential and/or commercial development.
- BTU's policy is to maintain an operating fund balance equal to at least 90 days of expenditures. If the fund balance is drawn down in any one year, the fund balance will be restored in the following year.

The way each utility calculates their Days Cash on Hand can differ. Thus, simply knowing how many days cash on hand a utility targets is not sufficient information to make a valid comparison among the utilities. For example, only AE calculates its Days Cash on Hand based on O&M expense, less Net Power Supply Cost. All other utilities in the benchmarking sample calculate Days Cash on Hand based on some variation of total O&M, which includes the cost of power supply. This difference has meaningful implications for comparing AE's working capital to these other utilities. Table 6-7 illustrates this point by applying the various different ways utilities apply their working capital calculations using AE's FY 2014 financial results.

Table 6-7
Variation in Calculation of Days Cash on Hand

Utility	FY 2014 Average Working Capital Reserve Balance (2)	Basis for Days Cash on Hand: Operating Expenses Considered	Basis for Days Cash on Hand: One Month Reserve Requirement	Resulting Days Cash on Hand
AE	$ 135,015,350	$ 509,906,281		97
CPS (1)	135,015,350	1,011,499,437		49
GP&L	135,015,350	1,011,499,437		49
Brownsville PUB (1)	135,015,350		$ 84,291,620	49
LP&L	135,015,350		115,755,313	35
BTU	135,015,350	1,011,499,437		49

Notes:
1) Days Cash on Hand calculations for CPS and Brownsville PUB will include repair and replacement funds, per their policies, but the calculations shown here are based on the working capital reserve balance alone for consistency.
2) Simple average of the balance at the beginning and end of FY 2014.

As shown above, AE's working capital calculation, which removes Net Power Supply Cost from O&M for the calculation of Days Cash on Hand, causes AE's Days Cash on Hand to appear higher, despite the fact that all the calculations are based on the same $135,015,325 working capital reserve balance. The salient fact is AE's Days Cash on Hand cannot be compared with other utilities without recognition of the differences inherent in the calculations. Another important difference is AE's Rate Stabilization Reserve, which is discussed in detail in Section 7. The Rate Stabilization Reserve is an important reserve to manage fluctuations in power cost. Given that this reserve mitigates risk associated with Net Power Supply Cost, it is appropriate to compare AE's combined Working Capital Reserve and Rate Stabilization Reserve levels with the working capital amounts set aside by other utilities included in the benchmarking survey.

NewGen is not recommending a change to AE's policy of removing Net Power Supply Cost from its calculation, as this is consistent with PUCT standards and in recognition of the existence of a Rate Stabilization Reserve.

It is worth noting that, in general, rating agencies measure Days Cash on Hand based on the following formula:

$$[(Total\ Unrestricted\ Reserves) \div (Total\ O\&M\ Expenses\ Excluding\ Depreciation)]\ X\ 365$$

Recommendations

NewGen recommends AE revise its policy to cap the amount of funds included in the Working Capital Reserve to either:

1. 45 days of O&M expense, less Net Power Supply Cost, plus all required transfers to the City, including the General Fund Transfer. This would recognize AE's firm financial obligation associated with these transfers, which are similar in nature to other non-recoverable O&M expenses. Also, this treatment recognizes the rating agency trend of viewing these costs as "above the line," similar to O&M costs, rather than "below the line."

   OR

2. 60 days of O&M expense, less Net Power Supply Cost. If AE wanted to account for the City transfers without changing its calculation methodology, it could simply increase the number of days required under the policy in recognition of these expenses. For example, in order to account for all the transfers to the City as proposed in FY 2015, including the General Fund Transfer, AE's policy on the number of days working capital would have to increase to 60 days from 45 days. Although this would still be consistent with public power norms, as discussed later, this would cause AE's policy to deviate from the 1/8th Rule prevalent at the PUCT.

Austin Energy may reasonably target a greater number of days, but NewGen recommends that there be some maximum limit on this reserve (e.g., 90 days). NewGen believes that placing a cap on this reserve is important as any regulatory review of the Working Capital Reserve balance would be grounded on the 1/8th Rule. We recommend any additional funds, that would be in excess of the cap, be accrued in the Repair and Replacement Reserve as needed to achieve AE's credit rating goal, as described later in this report.

NewGen also recommends that AE confirm compliance with Financial Policy No. 19 by considering the maximum debt service payment over the prospective year when judging the sufficiency of the Working Capital Reserve. The Working Capital Reserve is intended to be a financial cushion related to base, non-Power Supply costs, and debt service is a base cost. Thus, it makes sense to judge compliance with Financial Policy No. 19 based on the Working Capital Reserve balance.

The balance maintained in the Working Capital Reserve must also be evaluated in the context of overall cash on hand, which is a key indicator evaluated by rating agencies. Thus, it is not sufficient to merely maintain at least 45 days of O&M expense, less Net Power Supply Cost, in the Working Capital Reserve and confirm compliance with Financial Policy No. 19. Austin Energy must also consider the Working Capital Reserve contribution to overall financial liquidity in order to judge its sufficiency. This will be discussed in Section 10 – Rating Agencies.

Section 7
STRATEGIC RESERVE

The Strategic Reserve provides funds to offset revenue or expense fluctuations due to natural disasters or unplanned economic stress. The reserve was initially established in FY 1997 in Financial Policy No. 16 and was, at that time, called the Debt Management Fund. After Senate Bill 7, which deregulated electric power generation in Texas, City Council revised the reserve policy in 1999 changing it from a specific focus on debt reduction to include a broader focus on initiatives that improve the competitive position of AE. The Debt Management Fund was renamed the Strategic Reserve in FY 2004. At that time, the Strategic Reserve was comprised of three components: the Contingency Reserve, the Emergency Reserve, and the Competitive Reserve. In FY 2012, the Competitive Reserve was replaced by the Rate Stabilization Reserve. At that time there were was a $0 balance in the Competitive Reserve. The Strategic Reserve is currently comprised of the Contingency Reserve, the Emergency Reserve, and the Rate Stabilization Reserve. These reserves are discussed in more detail below.

In accordance with financial policy, the reserve fund's uses may include, but are not limited to, costs related to extended unplanned plant outages, insurance deductibles, unexpected costs due to revised Federal or State legislation, and liquidity support to stabilize fuel rates for customers due to unexpected changes in fuel costs or purchased power. In the past, the Strategic Reserve has been used to provide funding for capital projects, such as automated meter infrastructure, Electric Reliability Council of Texas ("ERCOT") nodal market technology systems, and clean energy initiatives. The Strategic Reserve has also been used to support operations via transfers to the Working Capital Reserve, when necessary.

The current fund balance targets for the Contingency Reserve, the Emergency Reserve, and the Rate Stabilization Reserve are calculated each year during the annual budget process as part of the proof of compliance with the financial policies. The historical balances for the reserves are shown in Table 7-1.

Table 7-1
Strategic Reserve Balances

	FY 2010 Audited	FY 2011 Audited	FY 2012 Audited	FY 2013 Audited	FY 2014 Audited
Contingency Reserve	$ 66,385,723	$ 68,122,357	$ 46,997,974	$ 25,487,620	$ 25,811,754
Emergency Reserve	66,385,723	68,122,357	69,484,824	80,508,399	80,765,286
Competitive Reserve (1)	8,923,801	4,283,995	N/A	N/A	N/A
Rate Stabilization Reserve (1)	N/A	N/A	0	0	0
Strategic Reserve Total	$ 141,695,247	$ 140,528,709	$ 116,482,798	$ 105,996,019	$ 106,577,040

Notes:
1) The Rate Stabilization Reserve replaced the Competitive Reserve in FY 2012; there were no funds in the Competitive Reserve at the time.

The target for each reserve is based on budgeted O&M expenses as shown in Table 7-2.

Table 7-2
Strategic Reserve Target Calculation

	FY 2012 Budget	FY 2013 Budget	FY 2014 Budget
Net Power Supply Cost	$ 408,863,639	$ 414,171,113	$ 470,475,674
Non-Power Supply Cost	422,699,344	489,759,428	491,322,159
Total O&M Cost	$ 831,562,983	$ 903,930,541	$ 961,797,833
Average Daily Costs (1)			
Net Power Supply Cost	$ 1,120,174	$ 1,134,715	$ 1,288,974
Non-Power Supply Cost	1,158,080	1,341,807	1,346,088
Target Basis			
Contingency Reserve	60 days of non-power supply costs		
Emergency Reserve	60 days of non-power supply costs		
Rate Stabilization Reserve	90 days Net Power Supply Cost (2)		
Target Balances			
Contingency Reserve	$ 69,484,824	$ 80,508,399	$ 80,765,286
Emergency Reserve	69,484,824	80,508,399	80,765,286
Rate Stabilization Reserve	100,815,692	102,124,384	116,007,700
Total Strategic Reserve Target	$ 239,785,340	$ 263,141,182	$ 277,538,272

Notes:
1) Annual costs divided by 365 days. Decimals not shown, but used in the resulting calculation of target balances.
2) Net Power Supply Cost for the Rate Stabilization Reserve should be net of ERCOT administration fees, which are recovered via the Regulatory Charge.

Contingency Reserve

Per Financial Policy No. 16, the Contingency Reserve shall not exceed a maximum of 60 days of O&M expense, less Net Power Supply Cost. This reserve is used for unanticipated or unforeseen events that reduce revenue or increase obligations such as extended unplanned plant outages, insurance deductibles, unexpected costs created by Federal or State legislation, and liquidity support for unexpected changes in fuel costs or purchased power that stabilizes fuel rates for AE customers.

In the event that the Contingency Reserve balance is less than the target, it is required to be replenished to the targeted amount within two (2) years. The Contingency Reserve can be replenished from net revenues[15] and funds may be transferred out of the reserve by City Council action. In 2012, City Council approved a budget amendment authorizing the transfer

[15] Net revenues, as mentioned in this report, refer to revenues in excess of O&M, debt service, transfers (including the general fund transfer), and cash capital spending that can be used to increase equity. Reserves that are not in compliance with financial policies would be priority.

of $24,750,000 from the Contingency Reserve to the Working Capital Reserve in order to increase AE's operating cash funds. A similar transfer for $10,900,000 occurred in FY 2013.

The Contingency Reserve can be used to replenish funds in other established reserves as needed. Given the role suggested by NewGen for the Rate Stabilization Fund (to be discussed), we would suggest the use of the Contingency Reserve for liquidity support for unexpected changes in Net Power Supply Cost be limited to instances when there are no funds available in the Rate Stabilization Reserve, which is designed for this purpose.

Emergency Reserve

The Emergency Reserve must have a minimum of 60 days of O&M expense, less Net Power Supply Cost. This reserve is only used as a last resort after the Contingency Reserve has been exhausted to provide funding in the event of an unanticipated or unforeseen extraordinary need of an emergency nature. There are no specified replenishment requirements that mandate how quickly the reserve should be replenished if there is a deficit in the reserve balance. Like the Contingency Reserve, the Emergency Reserve can be replenished from net revenues and funds may be transferred out of the reserve by City Council action.

NewGen views the Emergency Reserve as somewhat duplicative in purpose to the Contingency Reserve. There does not seem to be a purpose for this reserve beyond further supporting the goals of the Contingency Reserve. As a result, NewGen recommends the Emergency Reserve be eliminated and the funds in this reserve be used to 1) fully fund the Contingency Reserve and 2) partially fund the Rate Stabilization Reserve.

Rate Stabilization Reserve

In FY 2012, the Rate Stabilization Reserve replaced the Competitive Reserve portion of the Strategic Reserve. The Competitive Reserve was fully depleted at the time. The purpose of the Rate Stabilization Reserve is to stabilize utility rates in future periods. Per Financial Policy No. 16, the Rate Stabilization Reserve balance shall not exceed a 90 days of Net Power Supply Cost and may provide funding for:

- Deferring or minimizing future rate increases
- New generation capacity construction or acquisition costs
- Balancing of annual power supply costs (net power supply/energy settlement cost)

In essence, the reserve was established to protect customers from higher than anticipated power costs and is intended to defer the need for future rate increases when costs exceed existing rate revenues. The Rate Stabilization Reserve may also be used to absorb fluctuations in the net settlement costs associated with the ERCOT nodal market.

There are no specified replenishment requirements that mandate how quickly the reserve should be replenished if there is a deficit in the reserve balance.

Austin Energy's rates are subject to a City Council imposed affordability threshold that limits rate adjustments to no more than two percent per year, inclusive of Net Power Supply Cost (the "Affordability Goal"). Since the goal includes Net Power Supply Cost, which AE has limited ability to influence, the Rate Stabilization Reserve is critical for AE to manage Net Power Supply Cost to accommodate compliance with the Affordability Goal.

Purpose Revision

NewGen suggests that the purpose of the Rate Stabilization Reserve be narrowed to addressing only Net Power Supply Cost, which are typically recovered via the PSA. This would limit the focus of the reserve to costs that are largely outside the control of AE. The PSA is typically adjusted annually through the budgeting process. However, if the accrued over or under recoveries from the PSA are more than +/- 10 percent of the Net Power Supply Cost actually incurred, and are expected to persist for the year, then an adjustment to the PSA should be made to eliminate the over or under recovery balance within 12 months. The PSA is not designed to address immediate, short-term needs for cash stemming from outages or market events, as adjustments to the PSA will not yield increased cash for AE for approximately 90 days, whereas payments to ERCOT are generally due two business days after settlement. The Rate Stabilization Reserve, when funded, can help mitigate fluctuations in the PSA and provide AE funds to address significant, but temporary, changes in Net Power Supply Cost. This ability helps AE manage rate impacts of a highly volatile ERCOT wholesale market, where the maximum price is currently capped at $9,000 per MWh.

In recognition of this proposed narrowing of purpose, funds should not be taken from the Rate Stabilization Reserve to fund new generation capacity. Although AE's generation portfolio acts as a hedge for ERCOT market prices, this is a long-term influence and, in NewGen's opinion, the Rate Stabilization Reserve should be reserved to address short-term power supply issues. Austin Energy cannot be expected to offset long-term trends in the ERCOT market with a reserve, as it is not practical to set aside sufficient funds to mitigate long-term ERCOT price trends resulting from structural changes, such as the price of natural gas increasing or decreasing meaningfully and persistently for an extended period (e.g., several years). New generation projects should be funded with debt and cash reserves that resided in the Repair and Replacement Reserve (to be discussed in the next section). Cash funding generation projects from the Rate Stabilization Reserve only serves to increase the risk of non-compliance with the Affordability Goal.

ERCOT Market Exposure

The Rate Stabilization Reserve needs to be funded at a level that reflects the volatility in ERCOT market prices, especially when events cause the ERCOT market price to increase to the cap. Unplanned outages of AE's generation portfolio are a financial risk that the Rate Stabilization Reserve is necessary to address when they limit AE's ability to sell into the ERCOT market to offset electricity purchase costs.

To evaluate the probability of unplanned outages, NewGen evaluated historical operating data over the period 2011 through February 2015 for Fayette Power Project ("FPP"), Sand Hill Energy Center, South Texas Project ("STP"), and Decker Creek Power Station, as shown in Table 7-3. Although most outages are minor in nature, the frequency with which they occur demonstrates that there is more than a nominal risk of their occurrence.

Table 7-3
Outage Summary FY 2010 to FY 2015

	Unplanned Outages	Forced Outage Hours	Average Hours per Outage
Sand Hill Energy Center	[redacted]	[redacted]	[redacted]
Fayette Power Project (Combined Unit 1 & 2)	[redacted]	[redacted]	[redacted]
Decker Creek Plant (Combined Units 1 & 2)	[redacted]	[redacted]	[redacted]
South Texas Project – (Combined Units 1 & 2)	[redacted]	[redacted]	[redacted]

Unplanned outages do not incur independent of each other. In fact, over this historical period of time there were several occurrences where more than one power station was off-line at the same time. The timing of outages at STP and FPP, the plants with the fewest outages in Table 7-3, are summarized in Figure 7-1 to demonstrate this history.

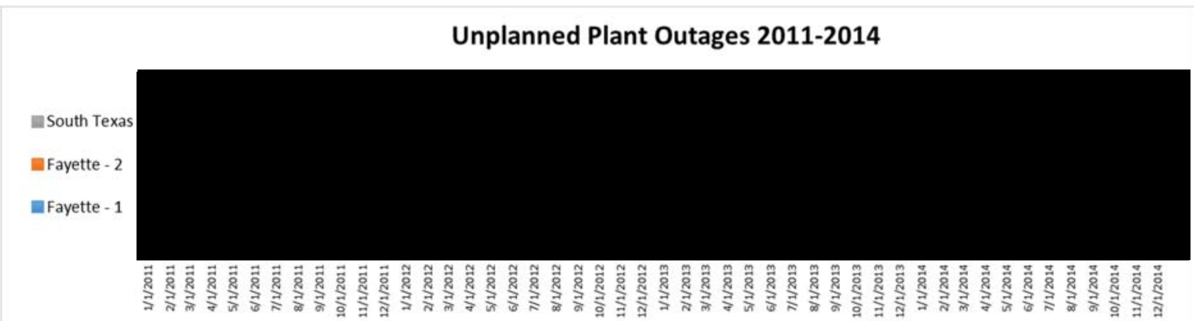

Figure 7-1. Unplanned Plant Outages 2011-2014

If an outage happens coincident with an increase in cost of power in ERCOT, as happened in August 2011, AE incurs higher costs for serving load and lost revenue related to the outage. NewGen analyzed the price per megawatt hour in the AE load zone for the period 2011 through 2015 and observed significant price spikes in the nodal market, which could pose a potential risk in the event that AE is not able to sell power into the nodal market to offset the costs of buying power from market (e.g., plant outages). For example, in February 2011 ERCOT reported that severe weather had led to the loss of 50 generation units amounting to 7,000 megawatts (“MW”). This situation was further exacerbated by the demand for power, which sharply increased. As a result, the market price in ERCOT rose to the system wide offer cap at the time of $3,000 per megawatt hour (“MWh”). Similarly, severe heat in the summer 2011 also caused price spikes and, in August 2011, AE experienced outages that resulted in approximately $20 million in additional costs related to buying energy at (or near) the cap. Since ERCOT energy payments are generally due within a week of the date incurred, and AE cannot recover cost increases from customers in such a short period of time, this resulted in significant financial stress for AE. Given the systematic increases in the ERCOT system wide offer cap over time, this risk has increasingly become more significant.

Table 7-4, as well as the Figure 7-2, identify the volatility of the nodal market and quantifies the maximum price per MWh on a monthly basis for 2011 through May 2015.

Table 7-4
ERCOT Maximum Cost in AE Load Zone ($/MWh)

	2011(1)	2012(2)	2013(3)	2014(4)	2015(5)
Jan	$ 29.54	$ 22.19	$ 1,051.84	$ 5,441.93	$ 495.61
Feb	3,001.11	120.60	591.53	1,273.97	1,553.06
Mar	3,001.00	2,999.99	1,046.22	5,281.40	705.56
Apr	1,080.38	1,047.86	3,243.98	926.56	607.26
May	2,964.44	1,024.51	844.31	612.17	265.09
June	3,001.00	2,988.47	441.25	359.78	
Jul	2,038.06	1,942.11	1,150.19	703.33	
Aug	3,001.00	767.38	617.28	629.25	
Sept	1,437.86	1,580.58	4,900.00	353.42	
Oct	797.05	896.90	1,996.18	568.72	
Nov	2,991.08	738.08	1,379.99	1,273.85	
Dec	1,016.61	500.91	794.09	540.81	

Notes:
1) Price cap increased to $3,000/MWh at the beginning of 2011
2) Price cap increased to $4,500/MWh in August 2012
3) Price cap increased to $5,000/MWh in June 2013
4) Price cap increased to $7,000/MWh in June 2014
5) Price cap increased to $9,000/MWh in June 2015

Note: on occasion, actual wholesale prices in some areas exceed the cap due to additional costs associated with transmission congestion

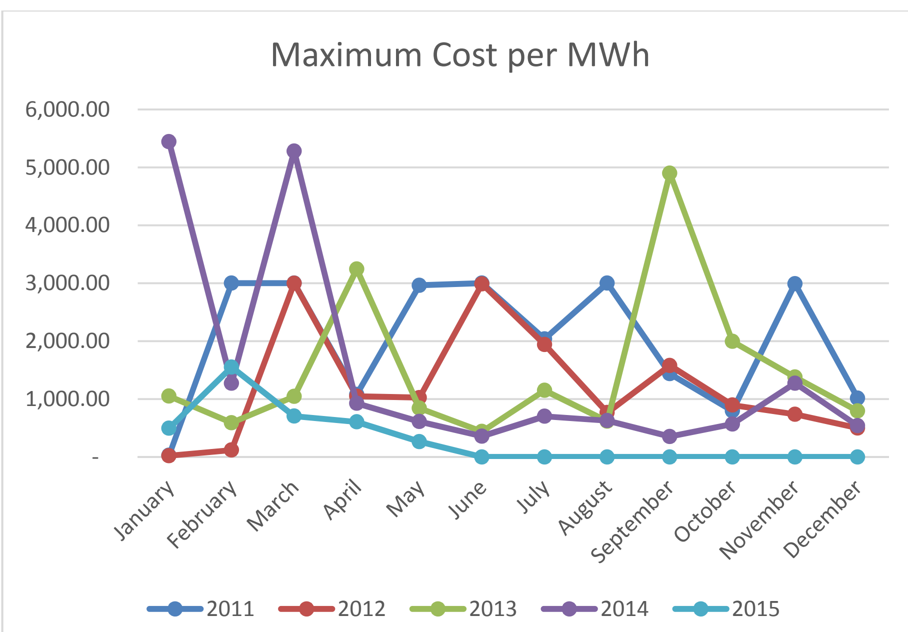

Figure 7-2. Maximum Cost per MWh

To understand AE's cost exposure during a catastrophic (i.e., worst case) event when market prices are high and key generating units are off-line, NewGen performed a high-level economic assessment of AE's exposure to ERCOT market prices. Assuming that AE could simultaneously lose two key generating units during an extended period of high market prices, we estimated ERCOT market cost exposure. For the purpose of the analysis, we assumed one of the two STP units and one of the two FPP units were off-line together. This event was actually observed during [redacted], [redacted], and [redacted].

As mentioned earlier, ERCOT caps the maximum market price. This cap has increased annually in recent years and is now $9,000 per MWh as of June 2015. As indicated in Table 7-5, market prices can be very high for short periods of time during the year. Over the study period, our analysis indicates that high prices can be observed between 1.5 percent to 2.0 percent of the hours in a year. For example, in 2011, ERCOT market prices hit the price cap at the time of $3,000 per MWh for 17.5 hours and were above $84 per MWh for 173 hours during that year. On average, power costs over these highest 173 hours averaged $709.12 in 2011. Assuming one of STP's two units and one of FPP's two units were off-line during this high pricing period, the total price exposure to AE could be as high as $90 million. If a similar pricing event were to occur in 2015, with the ERCOT market cap at $9,000 per MWh, the price exposure could be dramatically higher. A simple proration of prices during these peak pricing events up to the new ERCOT cap price would indicate a cost exposure of over $271 million. If only a single unit was off-line, either unit at STP or FPP, the estimated exposure under a $9,000 per MWh price cap could be in the range of $110 million to $160 million. If using the worst case scenario over the period is too conservative, an average approach yields a range between $43 million and $106 million when prorating historical costs up to the 2015 price cap. NewGen acknowledges that actual market cost exposure during a single event may vary significantly. However, given that the accumulation of reserves takes time, and the risk mitigation benefit associated with reserves is substantial, we recommended looking at extreme circumstances when evaluating appropriate funding levels.

Table 7-5
Market Power Cost Exposure During Peak Pricing Periods

	2011	2012	2013	2014	Maximum	Average
Min Data Set Price [1]	$ 84.48	$ 61.23	$ 78.81	$ 102.38		
Max Price [2]	3,001	3,000	4,900	5,442		
ERCOT Cap Price	3,000	4,500	5,000	7,000		
Number of Intervals	693	499	549	685		
Number of Hours	173.25	124.75	137.25	171.25		
Percentile [3]	1.98%	1.42%	1.57%	1.95%		
Average Price	709.12	230.13	284.17	370.00		
Total Cost	$ 90,420,737	$ 21,129,879	$ 28,705,860	$ 46,634,879	$ 90,420,737	$ 46,722,839
Normalized for Market Cap in 2015 [4]	$271,262,212	$ 42,259,758	$ 51,670,548	$ 59,959,130	$271,262,212	$106,287,912
STP						
Total Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Normalized for Market Cap in 2015	$160,693,375	$25,034,313	$30,609,184	$35,519,267	$60,693,375	$62,964,035
FPP						
Total Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Normalized for Market Cap in 2015	$110,568,836	$17,225,445	$21,061,365	$24,439,863	$110,568,836	$43,323,877

Notes:
1) Min Data Set Price is the lowest price in $/MWh within the percentile evaluated.
2) The Max Price in $/MWh can exceed the ERCOT cap price due to additional costs associated with transmission congestion.
3) Percentile identifies the percent of hours in a year within the dataset evaluated as the peak pricing period (e.g., 2% indicates the prices in the highest 175 hours in the year were evaluated in the dataset).
4) In June 2015 the ERCOT cap price increased to $9,000/MWh.

To approach this analysis from a different perspective, NewGen reviewed the timing of unplanned outages at FPP and STP over the period 2011 through 2014. Based on the frequency of unplanned outages, and the corresponding minimum and maximum market power prices that occurred concurrently during the outages, we estimated the range of additional power cost exposure to AE net of fuel and variable O&M costs at the various power stations.

Our analysis indicates that, on average over the four-year period, cost exposure under maximum market pricing conditions that occurred at the time of the AE unit outages was approximately $110 million. The associated average maximum settlement price over this period was $138.42 per MWh. During the same period, the minimum settlement power prices were $16.64 per MWh. In consideration of effectively managing adverse market conditions, NewGen recommends using the maximum settlement power price amount in this evaluation.

Based on this review, NewGen finds it reasonable that the Rate Stabilization reserved be funded between $110 million and $160 million. This funding range equates to approximately 85 to 120 days of net power costs. Given this range, NewGen recommends 90 days be reflective of the minimum appropriate level of funding and the new recommended maximum be set at 120 days.

Funding Source

NewGen recommends that any funds remaining from the Emergency Reserve, after fully funding the Contingency Reserve, should be deposited into the Rate Stabilization Reserve. Then, going forward, the Rate Stabilization Reserve should be funded from net credit balances remaining in the PSA over/under account balance upon periodic reevaluation of the PSA (typically annually), rather than included as a credit in the calculation of the subsequent PSA. For example, if there existed a $10 million over-recovery in the PSA over/under account balance when it was reevaluated, the $10 million would be transferred to the Rate Stabilization Reserve and the subsequent PSA would be based on a $0 contribution from the over/under account balance. Conversely, if there existed a $10 million under-recovery in the PSA over/under account balance when it was reevaluated, no transfer would be made to the Rate Stabilization Reserve and the $10 million debt would be included in the calculation of the subsequent PSA (as it would under current policies) or, alternatively, all or part of the $10 million debt could be funded from the Rate Stabilization Reserve (assuming funds existed in the Rate Stabilization Reserve and this was approved by City Council). This recommended funding process ties the funding source to the use of funds (i.e., Net Power Supply Cost under-recoveries are funded from prior Net Power Supply Cost over-recoveries).

Austin Energy could also consider funding the Rate Stabilization Reserve, when necessary, from an automatic surcharge attached to the PSA. Under this approach, meaningful deficiencies in the Rate Stabilization Reserve could be cured by an additional component within the PSA. However, this approach should be evaluated carefully before implementation to ensure it would endure a regulatory review, if initiated.

Benchmarking

In general, public power utilities adhere to similar financial metrics by prudently managing their reserves and aiming to achieve high credit ratings. The types of reserves utilized by these utilities vary widely, and many of the surveyed utilities maintain a simpler reserve structure than the one currently employed by AE. Additionally, AE's reserves have been established by City Council, whereas other utilities adhere to internal goals that have not been formally codified. In some cases, utilities that have not defined their reserves adequately are subject to external pressures to lower their reserves. This has proven to be the case in Garland, as GP&L does not have a cap on its rate stabilization fund and this utility is currently facing pressure from its rate payers to issue a refund. Although GP&L diverts excess cash into their rate stabilization fund, other utilities may utilize a different reserves to build up cash reserves. CPS, for example, has historically placed excess cash in their repair and replacement fund.

Of the Texas public power utilities surveyed, only GP&L has a rate mitigation fund similar to the Rate Stabilization Reserve utilized by AE. However, GP&L does not have a formal target and does not place a cap on this reserve.

LP&L includes use of funds for rate stabilization, unforeseen emergency situations, and for meeting the electric utility demand of any rapid or unforeseen increase in residential and/or commercial development as acceptable uses of the general reserve, which are similar to some of the purposes identified for AE's Strategic Reserve. However, LP&L does not have a separate reserve identified for these purposes.

CPS, Brownsville PUB and BTU do not have any formal reserves similar to AE's Strategic Reserve. However, CPS typically adjusts its fuel charge (the Fuel Adjustment) each month, reducing the risk of significant over or under recovery as it passes fuel and purchased power costs directly through to customers.

Table 7-6 provides a comparison of the types of reserves maintained by each utility.

Table 7-6
Utility Reserve Comparison

	AE	CPS	GP&L	BPUB	LP&L	BTU
Working Capital	✓	✓	✓	✓	✓	✓
Contingency	✓					
Emergency	✓					
Rate Stabilization	✓		✓		✓	
Non-Nuclear Decommissioning	✓					
Repair & Replacement	✓	✓		✓		

Recommendations

NewGen recommends the following modifications to reserves currently contained within the Strategic Reserve.

- Eliminate the Emergency Reserve in favor of maintaining the Contingency Reserve in order to have a single fund requiring up to 60 days of O&M expense, less Net Power Supply Cost. These two funds can be perceived externally as being duplicative. NewGen recommends the Emergency Reserve be eliminated and the funds in this reserve be used to 1) fully fund the Contingency Reserve, and 2) partially fund the Rate Stabilization Reserve. Initial funding for the Rate Stabilization Reserve will help offset the financial risk imposed by the Affordability Goal. By funding the Rate Stabilization Reserve, AE would be better prepared to address Net Power Supply Cost fluctuations and remain in compliance with the Affordability Goal.
- The purpose of the Rate Stabilization Reserve should be narrowed to addressing Net Power Supply Cost. In recognition of our proposed narrowing of purpose, funds should not be taken from the Rate Stabilization Reserve to fund new generation capacity. Although AE's generation portfolio acts as a hedge for ERCOT market prices, this is a long-term influence and, in NewGen's opinion, the Rate Stabilization Reserve should be reserved to address short-term power supply issues. Austin Energy cannot be expected to offset long-term trends in the ERCOT market with a reserve, as it is not practical to set aside sufficient funds to mitigate long-term ERCOT price trends resulting from structural changes, such as the price of natural gas increasing or decreasing meaningfully and persistently for an extended period (e.g., several years).
- Eliminate the naming convention of placing the Contingency Reserve and Rate Stabilization Reserve under the umbrella of the Strategic Reserve for transparency purposes. Instead,

the Contingency Reserve and Rate Stabilization Reserve would stand individually for their respective purposes. The labeling of these reserves as “strategic” by placing them under the Strategic Reserve heading does little to inform external stakeholders regarding their purpose or to lend credibility to the contention that these funds are necessary. Further, this change will better represent the segregation of purposes for the Contingency Reserve and Rate Stabilization Reserve.

- The role of the Contingency Reserve to lend stability to Net Power Supply Cost should be limited to circumstances when there are no funds available for this purpose in the Rate Stabilization Reserve, which was created for this purpose.
- Replace the current restriction on the Rate Stabilization Reserve that limits the balance to 90 days Net Power Supply Cost with a guideline to maintain a balance between 90 and 120 days of Net Power Supply Cost to allow for assessment of risk conditions existing in the ERCOT market.
- The Rate Stabilization Reserve should be funded from net credit balances remaining in the PSA over/under account balance upon periodic reevaluation of the PSA (typically annually), 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 Cost under-recoveries are funded from prior Net Power Supply Cost over-recoveries).

Section 8
REPAIR AND REPLACEMENT RESERVE

The Repair and Replacement Reserve is used as a source of funding for the AE's capital improvement program ensuring adequate cash resources to properly recapitalize the utility system. This includes providing extensions, additions, and improvements to the electric system.

This reserve has been used to fund various capital projects over time, including some major projects, such as additional generating capacity at the Sand Hill Energy Center. Between FY 2008 and FY 2009, approximately $65.0 million was transferred from the Repair and Replacement Reserve to the Working Capital Reserve to fund additional generation peaking capacity at the Sand Hill Energy Center. In FY 2010, an additional $2.0 million was transferred for the Sand Hill Energy Center.

Financial Policy No. 15 – Repair and Replacement Reserve

Austin Energy's current policy sets a maximum targeted balance to no greater than 50 percent of the prior year's depreciation expense in order to appropriately recapitalize the electric system. One-half of depreciation expense is considered to be a reasonable approximation of system-wide repair and replacement requirements funded from cash. Net revenues available after meeting the General Fund Transfer, capital investment (equity contributions from current revenues), and 45 days of working capital may be deposited in the Repair and Replacement Reserve per AE's policy.

The Repair and Replacement Reserve was not replenished following the transfer of funds to support the additional generating capacity at the Sand Hill Energy Center and, as a result, this reserve has not provided additional funding for projects in the last five years. A nominal ending balance of $64,071, which accounts for less than one percent of historical depreciation expenses, has been held in the Repair and Replacement Reserve since FY 2010, as shown in Table 8-1. There are no specified replenishment requirements that mandate how quickly the reserve should be replenished if there is a deficit in the reserve balance.

Table 8-1
Repair and Replacement Reserve Balance

	FY 2010 Audited	FY 2011 Audited	FY 2012 Audited	FY 2013 Audited	FY 2014 Audited
Repair and Replacement Reserve	$64,071	$64,071	$64,071	$64,071	$64,071

Financial Policy No. 14 – Debt-Equity Contribution Ratios

Financial Policy No. 14 states that capital projects should be financed through a combination of cash (equity contributions from current revenues) and debt. An equity contribution ratio between 35 percent and 60 percent is desirable with a long-term target of 50 percent, per Council policy. This financial policy relates to the Repair and Replacement Reserve insofar that, when this reserve is appropriately funded, it provides an additional source of equity for capital projects, if necessary. Having funds available in the Repair and Replacement Reserve allows AE to be better positioned to increase their equity contribution ratio, when needed. Higher equity contribution ratios are viewed favorably by the rating agencies.

Austin Energy is currently in compliance with their equity contribution policy, and the FY 2015 capital plan is currently funded at 59.6 percent debt and 40.4 percent equity. Table 8-2 outlines these equity/debt contribution ratios.

Table 8-2
FY2015 Equity/Debt Contribution Ratios

	FY 2015	% of Total	Equity/Debt
CIP Fund Cash Balance	$ 32,500,807	13.1%	Equity
Transfers from Operating to CIP Fund	67,787,565	27.3%	Equity
Commercial Paper	148,242,911	59.6%	Debt
	$ 248,531,283	100.0%	

If there were a balance in the Repair and Replacement Reserve, it could be used, as needed, to supplement transfers from operations (i.e., cash from operations) to balance the equity/debt proportions in years when the capital programs is unusually large or the transfer from operations needs to be reduced to balance the budget. This will prevent capital projects from being delayed due to short-term fluctuations in funding resources. In this way, the Repair and Replacement Reserve represents a base level of funding to help manage the variation in annual capital project spending in a way that is analogous to what the Working Capital Reserve does for O&M, less Net Power Supply Cost. This risk management reserve is also viewed favorably by credit rating agencies, as it adds additional liquidity and supports AE's ability to maintain a favorable debt to equity capital structure.

The target for the Repair and Replacement Reserve set at 50 percent of depreciation is appropriate as depreciation is representative of, but not really equal to, what is needed annually to recapitalize the overall system. Given that Financial Policy No. 14 recommends an equity contribution of between 35 percent and 60 percent, targeting a balance of 50 percent of depreciation for the Repair and Replacement Reserve is in alignment with, and supports, this policy.

CIP Fund

The CIP Fund provides equity funding for capital projects. It is funded and managed differently than the Repair and Replacement Reserve, as the CIP Fund is not a mechanism to build reserves to be used for unforeseen capital needs or future projects. The projected equity funding for specific capital projects is evaluated and an appropriate amount is transferred, via monthly contributions, from the Working Capital Reserve to the CIP Fund. Thus, the CIP Fund is tied to specific capital projects. Further, there are no Financial Policies directly related to the CIP Fund.

Revise the Nature of the Repair and Replacement Reserve

NewGen recommends altering the nature of the Repair and Replacement Reserve. Although its name implies it is intended to be used to recapitalize the existing system, the reserve has been used in the past to do more than just repair and replace existing system assets. Even in its stated purpose of "providing extensions, additions, replacements, and improvements to the electric system," it is clear the purpose of the reserve extends beyond repairing and replacing the system that is already in service. However, the target funding level at 50 percent of depreciation is predicated on the idea that the reserve is intended only for repairs and replacements of the existing system. Thus, NewGen recommends that the Repair and Replacement Reserve targeted funding be expanded to reflect the reality of its more expansive role and, in particular, NewGen recommends there be no artificial limit placed on the reserve. Rather than setting a limit on this reserve in particular, NewGen recommends that the reserve funds, in total, comply with the rating agency standards for the credit rating AE strives to attain/maintain. Per the 2003 Strategic Plan, and other representations such as the annual budget, AE's goal is to achieve/maintain a 'AA' rating. Thus, the rating agency guidelines for this designation should guide and inform the evaluation of appropriate reserves overall, and inform the appropriate limit for the Repair and Replacement Reserve in particular. The balance in the Repair and Replacement Reserve should be reviewed periodically (likely during the budget process) to ensure the balance is appropriate.

Recent guidance indicates that 150 Days Cash on Hand ***or more*** is appropriate for AE to adhere to the norms of the 'AA' rated public utility requirements, among other requirements.[16] In fact, even 150 Days Cash on Hand would be less than the median Days Cash on Hand for the Fitch 'AA-' rated utilities in AE's peer group, which is 180 Days Cash on Hand.[17] Thus, targeting 150 Days Cash on Hand, at a minimum, is an appropriate action to conform AE's liquidity to its targeted rating requirements. Given this priority, NewGen recommends a Repair and Replacement Reserve funding target, in consideration of all other limits existing on other reserves, at a level necessary for the attainment of at least 150 Days Cash on Hand in the manner consistent with the way the rating agencies view AE's reserves (i.e., even reserves that are restricted from AE's point of view, such as the Strategic Reserve, are considered in Days Cash on Hand by the rating agencies because they are not restricted by contract or regulation or earmarked for a specific purpose).

This recommendation is in alignment with the practice at CPS, where there is no set limit on their Repair and Replacement Account and CPS internally targets an overall 150 Days Cash on Hand, among other goals.

The recommendation to remove the policy set limit on this reserve (i.e., 50 percent of depreciation) is also palatable given that NewGen is recommending that the Emergency Reserve, which had no formal maximum balance set by policy, be eliminated.

[16] Moody's Investor Service, *U.S. Public Power Electric Utilities with Generation Ownership Exposure,* November 9, 2011, page 32. – Rating for Aa is ≥ 150 days to 249 days adjusted days liquidity on hand (three-year average). Moody's calculation of adjusted days liquidity on hand *may* include unused lines of credit or commercial paper facilities but, per AE staff, the commercial paper facility does not factor into Moody's calculation of Days Cash on Hand for AE.

[17] "U.S. Public Power Peer Study," Fitch Ratings, June 13, 2014.

In accordance with the recommendation outlined above, NewGen recommends the Repair and Replacement Reserve be renamed the Capital Reserve to more aptly describe its purpose and intended use.

If AE opts ***not*** to pursue the recommended change in the reserve discussed above, in order to provide AE the financial flexibility regarding capital projects envisioned in the establishment of the Repair and Replacement Reserve, NewGen recommends that AE replenish this reserve to its upper limit of 50 percent of the prior year's depreciation as soon as practical. Based on FY 2014 depreciation expense, this would amount to a target balance of approximately $76,225,000.

By achieving a suitable balance, AE will be able to recapitalize the utility system, as well as make necessary extensions and improvements, with an additional source of cash funding, as needed, to smooth the variation in capital needs of the utility. Without a sufficiently funded Repair and Replacement Reserve, capital that would ideally be funded from cash to adhere to Financial Policy No. 14 may have to be funded from debt or, alternatively, the capital projects may be delayed. If the Repair and Replacement Reserve were adequately funded, AE would be better positioned to meet its debt-equity goal of an equity contribution ratio between 35 percent and 60 percent, and a long-term goal of 50 percent, without the risk of delaying capital projects.

Benchmarking

As previously stated, NewGen conducted a benchmarking analysis with regards to utility reserve funds for CPS, GP&L, Brownsville PUB, LP&L, and BTU. Of these five Texas public power utilities surveyed, only CPS and Brownsville PUB maintain a repair and replacement reserve fund. The benchmarking results are summarized below:

- GP&L, LP&L, and BTU do not possess a repair and replacement reserve fund.
- CPS maintains a "Repair and Replacement Account" that is restricted in accordance with their bond ordinances. Prior to FY 2014, a portion of the Repair and Replacement Account was designated a Community Infrastructure and Economic Development ("CIED") Fund. Historically, one percent of the prior fiscal year's electric base rate revenue, excluding applicable fuel adjustments and regulatory fees, had been re-designated from the Repair and Replacement Account to the CIED fund to support economically beneficial capital projects.

  The CIED fund has since been discontinued; however, in lieu of CIED funding, the City of San Antonio may alternatively request an equivalent amount of general funds to be transferred for its use. In such cases, the amount previously designated for CIED funding is returned to the Repair and Replacement Account and general funds are transferred to the City. In accordance with bond ordinances, the combined total of all payments to the City may not exceed 14 percent of gross revenues.

  Further, CPS currently transfers six percent of gross system revenues, plus any excess revenues after other obligations are paid (including the transfer to the City of San Antonio), into the Repair and Replacement Account.
- Brownsville PUB maintains a "Capital Improvement Fund" that may be used for making any capital improvements to their electric system for meeting contingencies of any nature in

connection with the operations, maintenance, improvement, replacement, or relocation of properties. Brownsville PUB's ordinance requires the City of Brownsville to deposit net revenues of the electric system into a capital reserve account of the capital improvement fund, only after the minimum requirements have been met for the following obligations: two months' worth of maintenance and operating expenses, debt service fund requirements, lien reserve fund requirements and obligations, and finally the transfer to the City of Brownsville's general fund.

Brownsville PUB's ordinance requires an annual payment sum equal to $3 million until the amount on deposit in the Capital Reserve Account equals or exceeds $15 million. In the event that such annual payments are not made, Brownsville PUB is required to establish sufficient rates and charges to cure any deficiency within one year. If, however, cash and investments in the Capital Reserve Account equal the $15 million capital amount, no deposits will be required to be made.

Recommendations

NewGen recommends the following modifications to the Repair and Replacement Reserve.

- NewGen recommends the nature of the reserve be modified to allow the targeted funding to be expanded to reflect the reality of its more expansive role and, in particular, NewGen recommends there be no artificial limit placed on the reserve. Rather than setting a limit on this reserve at 50 percent of depreciation, NewGen recommends that the unrestricted reserve funds, in total, comply with the rating agency standards for the credit rating AE strives to attain/maintain. Per the 2003 Strategic Plan, and other representations such as the annual budget, AE's goal is to achieve/maintain a 'AA' rating. Thus, the rating agency guidelines for this designation should guide and inform the evaluation of appropriate reserves overall, and inform the appropriate limit for the Repair and Replacement Reserve in particular.
- In accordance with the recommendation outlined above, NewGen recommends the Repair and Replacement Reserve be renamed the Capital Reserve to more aptly describe its purpose and intended use.

Section 9
NON-NUCLEAR DECOMMISSIONING RESERVE

The objective of the Non-Nuclear Decommissioning Reserve is to accumulate sufficient funds over the remaining life of each power plant to pay for decommissioning activities after the plant is taken out of service. The annual contributions to the reserve would be secured as an annual operating expense and subsequently recovered from customers through rates. By doing so, there is better alignment between the customers benefiting from the power plants while they are in service and the customers paying for the eventual dismantlement of the facilities in the future.

To be equitable, or as close as is practical, AE would start setting aside funds for the eventual decommissioning of a plant the day it was put in service. Under this policy, customers that derive the benefits of generation also pay for its eventual decommissioning as the plant is in operation. This is how the cost for decommissioning a nuclear plant is managed. It may not be practical to implement such a policy at this time, but the earlier AE starts the process of setting aside funds for each generation unit, the lower the potential rate impact and the more equitable the recovery of these costs.

Financial Policy No. 21 – Non-Nuclear Decommissioning Reserve

The Non-Nuclear Decommissioning Reserve was implemented via Financial Policy No. 21 in FY 2002. The Holly Power Plant was the first plant planned for via this reserve. Per AE's policy, funding for the decommissioning of a plant will be set aside over a minimum of four years prior to the expected plant closure. The funds in the Non-Nuclear Decommissioning Reserve are restricted to use for generation decommissioning costs, but not associated with a particular plant or unit.

Table 9-1 summarizes the historical Non-Nuclear Decommissioning Reserve balance. All of the funds currently in the reserve are to be used for decommissioning activities at the Holly Power Plant.

Table 9-1
Non-Nuclear Decommissioning Reserve Balance

	FY 2010 Audited	FY 2011 Audited	FY 2012 Audited	FY 2013 Audited	FY 2014 Audited
Non-Nuclear Decommissioning Reserve	$14,873,603	$19,541,193	$15,093,817	$11,490,144	$8,138,072

The "Non-Nuclear Decommissioning Cost Study" provided to AE, and attached as Appendix 2, summarizes the reserve amounts that should be set aside for decommissioning AE's ownership share of FPP, Decker Creek Units 1 and 2, and Sand Hill Energy Center. Please note that the Decker Creek decommissioning cost estimate is based on a site-specific engineering cost estimate, while FPP and Sand Hill Energy Center decommissioning cost estimates were developed using a benchmark approach based on scaled costs from actual decommissioning costs for similar power plants and commission approved decommissioning cost data. Table 9-2 identifies the range of decommissioning costs that are projected to be needed to decommission these generation facilities per the study's results.

Table 9-2
Estimated Non-Nuclear Decommissioning Costs

Facility	Retirement Year	Decommissioning Cost Estimate (1) Low	Decommissioning Cost Estimate (1) High
Decker Creek Units 1 & 2	2018	$ 18,551,374	$ 27,721,374
Fayette Power Project (2)	2025	15,780,000	29,590,000
Sand Hill Energy Center	2030	11,856,000	22,082,000
Total		$ 46,187,374	$ 79,393,374

Notes:
1) Decommissioning costs shown in Table 9-2 are in real dollars (i.e., 2015 dollars).
2) The cost estimate listed for FPP is for AE's ownership share of the plant (i.e., not the total plant).

Note that there is also a Nuclear Decommissioning Trust associated with AE's ownership in the South Texas Project that is established and overseen by Federal regulations. The balance in the Austin Energy Nuclear Decommissioning Trust in FY 2014 was approximately $196,654,000 per the City's FY 2014 CAFR.

Benchmarking

As previously stated, NewGen conducted a benchmarking analysis with regard to utility reserves for CPS, GP&L, Brownsville PUB, LP&L, and BTU. None of these five public power utilities surveyed maintains a non-nuclear decommissioning reserve.

Recommendations

NewGen recommends the following modifications to the Non-Nuclear Decommissioning Reserve.

- Given the near-term goal of retiring Decker Creek Units 1 and 2 by FY 2018, and AE's financial policy requiring that funds be set aside over a minimum of four years prior to the expected plant closure, NewGen would recommend that AE begin accumulating additional funds in the Non-Nuclear Decommissioning Reserve as soon as practical.
- It is simply not practical for AE to transition to fully recognizing the cost of decommissioning all its generation facilities in this reserve immediately, given the Affordability Goal constraints. However, AE should begin funding the reserve for the near-term need of retiring Decker Creek Units 1 and 2 promptly and to the fullest extent possible. Any funding that *might* be beyond the needs of decommissioning the Decker units can be applied to the next facility to be decommissioned. Thus, NewGen recommends targeting the high end of the estimated range of costs for decommissioning. As mentioned in the separate "Non-Nuclear Decommissioning Cost Study" report, there is good reason to believe the costs for AE will be at the higher, rather than lower, end of the range identified. Further, although

the Decker decommissioning cost estimate was developed based on a site specific engineering cost estimate, there are still areas of the cost that could represent significant liabilities that need further investigation (e.g., remediation needs). Plus, as previously noted, if the cost of decommissioning the Decker units proves to be less than the high end of the estimate, the savings can be applied to the decommissioning of the next plant. Thus, funds set aside in the reserve will be used for their intended purpose, even if they end up not being needed at Decker.

Section 10
RATING AGENCIES

Rating agencies advise investors as to the creditworthiness of debt issuers. Therefore, rating agencies are regularly monitoring the financial health of a utility with particular emphasis on the utility's ability to repay outstanding debt obligations under adverse business and/or political circumstances. Based on this review, a municipal debt rating is given. A municipal debt rating is the bond rating agency's assessment of the credit-worthiness of an obligor with regards to a particular obligation. The bond rating process essentially provides the investor with a "grade" for a municipality related to the amount of risk attached to a given bond investment. A higher rating indicates that an issuer has been determined to have a better ability to repay interest and principal on a particular bond investment, while those issuers rated at a lower level are considered to be more risky. When assessing risk, a rating agency considers many factors. For example, in a December 2012 Fitch Ratings publication[18], the following key drivers were identified in establishing U.S. Public Power Ratings:

1) Rate Sufficiency and Flexibility – A public power utility's ability and willingness to maintain rates to meet all of its financial obligations is of paramount importance. Fitch considers how a utility's rate structure affects its capacity for the full and timely recovery of costs, as well as its flexibility to raise additional revenue. Ratemaking autonomy and the process for adjusting rates factor into this analysis.

2) Comprehensive Strategic Planning and Risk Management – The extent of strategic planning and risk management performed by a utility is a key indicator of management's preparedness and sophistication, and an important rating factor. Fitch typically reviews prior strategic and financial plans versus actual outcomes, as well as newly adopted strategies, to gauge management effectiveness.

3) Resource Adequacy and Performance – Ensuring the adequacy of power supply resources to meet current and projected demand is a fundamental planning requirement of public utilities. Together with demonstrating operating efficiency, it is an important factor in providing a low-cost, reliable energy supply. Fitch measures resource adequacy and performance against industry standards for cost and reliability.

4) Financial Strength and Forecasting – The strength and stability of a utility's financial metrics reveal its ability to meet all financial obligations, and detailed financial forecasting provides an indication of future performance. Fitch reviews a broad array of historical and projected financial metrics in an assessment of a utility's financial strength, as well as a utility's adherence to adopted financial policies. Financial metrics focus on three core areas: cash flow, liquidity, and capital structure.

5) Service Area Composition and Depth – Service area characteristics demonstrate the breadth, depth, and stability of the utility's constituents, as well as their financial wherewithal. Fitch considers customer composition and concentration, income levels and employment, population, and sale growth trends in this assessment.

[18] *U.S. Public Power Rating Criteria*, Fitch Ratings, December 18, 2012.

Reserve levels are an important factor in several key drivers listed by Fitch. Specifically, with respect to AE, the level of reserves directly impacts:

- Rate Sufficiency and Flexibility – Reserves provide AE an important tool to ensure the adequacy of rates in meeting financial obligations while remaining flexible and meeting the utility's Affordability Goal.
- Comprehensive Strategic Planning and Risk Management – The concept, use and administration of reserves requires a long-term planning perspective. Most reserves are long-run financial strategies as funds are accumulated and applied as needed gradually over time. Reserves are a key component of AE's risk management strategy, ensure the utility's financial health, and protect ratepayers from extreme market volatility.
- Financial Strength and Forecasting – Reserves improve AE's liquidity and overall equity position in its balance sheet. Both of these benefits support the utility's financial policies and are important positive factors in the evaluation of the utility's overall financial strength, particularly when cash flow becomes constrained. Austin Energy's financial policies specifically related to financial strength ensure adequate liquidity and reserve funding levels for the utility by establishing the following requirements, many of which are also summarized in the previous sections:
    - Policy No. 10: Minimum quick ratio of 1.50
    - Policy No. 11: Maintain operating cash equivalent to 45 days of budgeted O&M expense, less Net Power Supply Cost
    - Policy No. 15: Establishment of a Repair and Replacement Reserve
    - Policy No. 16: Establishment of a Strategic Reserve
    - Policy No. 19**:** Minimum of unrestricted cash on hand equal to six months debt service for the outstanding Parity Electric System Obligations
    - Policy No. 20: Current revenue, which does not include the beginning balance, will be sufficient to support current expenditures or, if projected revenue in future years is not sufficient to support projected requirements, ending balance may be budgeted to achieve structural balance.

In addition to Fitch, Standard & Poor's and Moody's Investors Service have similar criteria varying in the particular characteristics evaluated and weight given. Per the FY 2014 CAFR, bond ratings for AE as of September 30, 2014 were 'A1' (Moody's Investors Service, Inc.), 'AA-' (Standard & Poor's), and 'AA-' (Fitch). Austin Energy's financial goal is to achieve/maintain a 'AA' credit rating. Current ratings have not yet achieved this goal.

Payments to the City

Since the financial crisis beginning in 2007, largely attributed to loose lending practices, rating agencies have reassessed their credit rating criteria taking a harder look at utility liquidity, equity, and cash flow. With respect to MOUs, one important change has been associated with the treatment of payments to the city. Largely driven by Moody's, payments to the city are increasingly being viewed as a firm expense obligation of the utility. In a Moody's Investor

Service Newsletter from November 2011, the rating agency describes treatment of payments to the city in its debt service coverage calculation.[19]

> **Adjusted Debt Service Coverage Ratio OR Fixed Obligation Charge Coverage Ratio**
>
> Moody's has made a standard adjustment to the traditional debt service coverage ratio called the "Adjusted Debt Service Coverage Ratio," which recognizes that most public power utilities transfer a portion of their surplus revenues to a municipal government, typically to a city or county at an agreed upon level. While the transfers come after debt service in the legal flow of funds, practically, the transfer is a requirement and in many cases the transfer is made on a monthly basis. Therefore, Moody's Adjusted Debt Service Coverage Ratio treats the transfer as an operating expense, whereas the traditional or bond ordinance debt service coverage ratio does not.

From a financial planning and liquidity perspective, treating payments to the City as a firm expense obligation of AE makes sense, particularly as this payment is substantial and is an important revenue source for the General Fund.

Credit Rating Metrics

Bond rating agencies publish the financial and operating figures that support their rating decisions. Specific financial measures, such as the debt service coverage ratio, equity percentage of capital, and adjusted days liquidity on hand, are examples of critical factors utilized in analyzing public power utilities. Austin Energy's financial policies are an essential component of the ratings process. These financial metrics are included in policies related to debt, capital projects and routine maintenance, flow of funds, general fund transfer, liquidity and reserves, and decommissioning.

Austin Energy has consistently demonstrated a strong financial position as evidenced by their 'AA-' rating from Fitch and 'A1' rating from Moody's. In order to maintain these ratings, AE is expected to continue to improve liquidity, among other factors. Further, it is important to demonstrate strong equity levels of more than 50 percent to indicate adequate cost recovery and ample debt capacity for future capital needs.

Historically, utilities with lower debt ratios and higher debt service coverage ratios have received higher ratings. However, this is not an absolute metric without exceptions. Varying operational characteristics may result in unique credit considerations and financial metrics that are less comparable for a given rating level. Liquidity measures, like Days Cash on Hand, provide estimates regarding a utility's ability to ensure adequate cash flow and the ability to meet current liabilities while funding unanticipated expenses. A higher level of liquidity bodes favorably in ratings evaluations. In addition, a utility's capital structure, specifically the equity-

[19] *U.S. Public Power Electric Utilities with Generation Ownership Exposure*, Moody's Investors Service, November 9, 2011.

to-capitalization ratio, indicates a utility's ability to grow equity over time. A rising equity ratio is viewed favorably, as it suggests adequate cost recovery in rates.

According to Fitch, AE has demonstrated sound financial performance. However, liquidity and cash flow metrics remain somewhat low relative to rating category medians. Fitch has also raised concerns regarding AE's limited rate flexibility. The utility's rates are subject to a City Council imposed Affordability Goal. Fitch has indicated this could ultimately impede financial performance. This concern is further exacerbated by AE's consideration for adding, "costlier renewable resources to its resource portfolio."[20] Moody's also notes that failure to implement rate increases in a timely manner would adversely affect AE's current credit rating. These concerns highlight the risk associated with AE's Affordability Goal. A comparison of other utilities' Fitch bond ratings included in the benchmarking study are listed in Table 10-1.

Table 10-1
Liquidity Metrics and Credit Rating for
Selected Texas Municipal Utilities

Utility	Fitch Credit Rating	Days Cash on Hand	Debt Service Coverage
AE (1)	AA-	90	2.3x
CPS (2)	AA+	196	>2.0x
GP&L (3)	AA-	327	2.3x
BPUB (4)	AA-	>230	2.2x
LP&L (5)	A+	123	2.4x
BTU (6)	A+	117	2.2x

Notes:
1) AE metric provided per Fitch's April 2015 assessment
2) CPS metric provided per Fitch's November 2014 assessment
3) GP&L metric provided per Fitch's January 2015 assessment
4) BPUB metric provided per Fitch's March 2014 assessment
5) LP&L metric provided per Fitch's March 2015 assessment
6) BTU metric provided per Fitch's May 2015 assessment

Liquidity, Leverage and Debt Service Coverage Metrics

To quantify AE's reserve requirement levels, Fitch and Moody's credit rating evaluation criteria related to liquidity, leverage, and debt service coverage are summarized in Table 10-2.

[20] "Fitch Affirms Austin's (TX) Electric Utility Systems Revs at 'AA-'; Outlook Stable," April 23, 2015.

Table 10-2
Credit Rating Evaluation Criteria

Metric	Strong Credit Rating of at least AA	Midrange Credit Rating (A)	Weak Credit Rating of at least Ba
Capital Structure - Equity/Capitalization			
Fitch	> 40%	20% - 40%	< 15%
Moody's	> 50%	> 25%	> 0%
Liquidity - Days Cash on Hand			
Fitch	> 120	60 - 90	< 60
Moody's	≥ 150	90 - 150	< 90
Cash Flow - Debt Service Coverage			
Fitch	> 2.0x	1.5x - 2.0x	< 1.5x
Moody's	> 2.0x	1.5x - 2.0x	< 1.5x

Data Sources:
- "U.S. Public Power Electric Utilities with Generation Ownership Exposure," Moody's Investor Service, November 9, 2011, Page 32.
- "U.S. Public Power Rating Criteria," Fitch Ratings, December 18, 2012, Page 9.

Austin Energy's Financial Policy No. 14, which specifies an equity contribution ratio between 35 percent and 60 percent, and Financial Policy No. 6, which specifies a minimum debt service requirement of 2.0x, agree well with rating agency liquidity metrics for 'AA' rated utilities. However, historically, AE has not met the cash liquidity metric for 'AA' rated utilities as measured by Days Cash on Hand applied to total eligible reserves. The median Days Cash on Hand for similarly rated utilities by Fitch is 180 days, which is well in excess of AE's current level of Days Cash on Hand.[21] Ratings are the result of many factors, and simply attaining (or not attaining) 180 Days Cash on Hand is not, in of itself, cause to upgrade (or downgrade) a utility's rating. In AE's case, there are other factors, such as its relatively low leverage, that have facilitated its 'AA-' rating. However, in order to maintain its current rating, AE is expected to improve its Days Cash on Hand to be more in alignment with its similarly rated peers. In its April 2015 publication, Fitch stated, "Liquidity and cash flow metrics remain somewhat low relative to rating category medians, but additional improvement ***is expected*** based on AE's multiyear financial forecast." (emphasis added)[22] Thus, it is important for AE to continue to improve its liquidity position, including its Days Cash on Hand, in order to maintain its current rating, or improve to a 'AA' rating.

When comparing Days Cash on Hand metrics, it should be noted that Fitch and Moody's use different calculations. For Fitch, the rating agency includes all expenses, including net power costs less depreciation, and divides this amount by eligible cash reserves. Moody's calculation is more complicated and may add acceptable bank lines of credit and commercial paper to the reserve calculation. However, in discussion with AE staff, it is our understanding that Moody's does not include AE's commercial paper program in its Days Cash on Hand calculation due to restrictions on the use of these funds. Moody's, similar to Fitch, includes all O&M expenses,

[21] "U.S. Public Power Peer Study," Fitch Ratings, June 13, 2014.
[22] "Fitch Affirms Austin's (TX) Electric Utility Systems Revs at 'AA-'; Outlook Stable," April 23, 2015.

including Net Power Supply Cost, in its calculation. Because Moody's does not include commercial paper in AE's Days Cash on Hand calculation, the Days Cash on Hand calculation is similar for both Moody's and Fitch. Austin Energy's Days Cash on Hand calculation for compliance with Financial Policy No. 11 differs from those of the rating agencies, as AE's calculation excludes Net Power Supply Cost. Net Power Supply Cost is protected with the Rate Stabilization Reserve and Contingency Reserve. Other costs are protected with the Working Capital, Repair and Replacement, Non-Nuclear Decommissioning and Contingency Reserves.

For the purposes of this study, we have assumed that all reserves discussed and described in this report are eligible for inclusion in the rating agency Days Cash on Hand calculation, except for the Non-Nuclear Decommissioning Reserve and CIP Fund. This appears to be consistent with the treatment by rating agencies based on a review of their calculated Days Cash on Hand. Only reserves that are externally restricted, such as the Nuclear Decommissioning Trust, or are earmarked for a specific purpose, such as the Non-Nuclear Decommissioning Reserve and CIP Fund, are excluded from consideration by the rating agencies.

Recommendation

NewGen recommends the following modifications to AE's total cash reserve levels.

- To maintain its current 'AA-' credit rating, AE must continue to improve its liquidity to better align with its 'AA-' rated peers. In furtherance of this objective, NewGen recommends AE target total reserve levels that achieve at least 150 Days Cash on Hand as measured by the rating agencies. NewGen recommends that reserve fund balances be summed for the Working Capital, Repair and Replacement, Rate Stabilization and Contingency Reserves for this calculation. Funds in the Non-Nuclear Decommissioning Reserve and CIP Fund should be excluded from this internal calculation. AE intends these funds to be restricted for decommissioning and specific capital projects and, consistent with this purpose, these funds should not contribute to Days Cash on Hand. This appears to be consistent with the treatment by rating agencies based on a review of their calculated Days Cash on Hand.
- The Repair and Replacement Reserve (recommended to be renamed the Capital Reserve and be unconstrained by the current 50 percent of deprecation limit as described in Section 8) should act as a balancing account to ensure that AE meets or exceeds the 150 Days Cash on Hand goal.

Section 11
PUBLIC UTILITY COMMISSION OF TEXAS

Until deregulation of the ERCOT electricity market in the late 1990s, the PUCT rarely regulated the financial performance of municipal utilities and was largely unfamiliar with municipal utility finances and capital structure. However, upon the deregulation of the ERCOT electricity market, the PUCT began to frequently regulate transmission assets owned and operated by municipal utilities. In these early days of PUCT municipal utility regulation, the PUCT struggled with the concept of a “cash basis” revenue requirement and a municipal utility capital structure.

With respect to reserves, the PUCT was familiar with IOUs and their request for a return on rate base. For IOUs, reserves were a small component of rate base with the working capital reserve being the only common reserve consistently included in cost of service filings. The working capital reserve is a component of rate base. For IOUs, including reserves in a revenue requirement calculation was unnecessary, as return on rate base was more than adequate to meet the utility’s total capital needs.

As the PUCT reviewed multiple municipal utility revenue requirement applications associated with transmission cost of service, they realized that the IOU capitalization and rate setting model was not a good fit for MOUs. To accommodate this difference, the PUCT amended its original transmission cost of service rate filing package requirements to allow municipal utilities the option to submit revenue requirements using a cash flow or cash basis approach. Per the December 16, 1999 approved transmission cost of service rate filing package for Non-Investor Owned Transmission Service Providers in the Electric Reliability Council of Texas (“TCOS Filing Package”), the cash flow method is described as follows:

> A TSP may elect to use the cash flow method for determining its transmission revenue requirement based on the Historic Year. If the TSP elects to use the cash flow method, the Commission shall consider reasonable cash needs in to the following categories:
>
> A. debt service (including principal and interest) for long-term and short-term debt;
> B. funding of reserve requirements on both long-term and short-term debt as set forth in revenue bond and debt ordinances;
> C. for municipal utilities, annual payments for transfers to the city’s general fund at rates established by the municipal utility’s governing authority, to the extent such amounts are not recovered through other elements of the TCOS;
> D. capital lease payments and/or finance lease payments; and
> E. annual payments to provide internally generated funds for construction, system improvements, and repair and replacement.
>
> Transfers to the general fund (which may have different names in different municipal utility systems), debt service, and funding of reserve requirements shall be functionalized, subject to commission

> review, to the transmission function on a basis comparable to that used to allocate such costs to the other functions of the municipal utility.
> Lease payments and capital expenditures shall be included to the extent they [sic] can be directly assigned to the wholesale transmission function.
> Transmission related costs other than the elements described above should be determined in accordance with the appropriate instructions contained in these rate-filing packages. [sic]

As indicated in Item E above, the PUCT allows support for various reserves in the revenue requirement calculation. It is up to the utility to justify the need and funding amount for each reserve. Therefore, it is NewGen's position that municipal utilities like AE have the opportunity to successfully include reserve funding requirements in any revenue requirement request before the PUCT. However, the success of the request is directly related to the use and justification of the reserves.

Working Capital Reserves

Because the PUCT is extremely familiar with working capital reserves, as IOUs use these types of reserves in ways similar to MOUs, the PUCT has very clear guidelines with respect to establishing working capital reserves. These guidelines are referred to in the TCOS Filing Package, as follows:

> The amount to be included will be in accordance with P.U.C Subst. R. 25.231(c)(2)(B)(iii). Municipal utilities, cooperatives, and river authorities shall be allowed to use the one-eighth method to calculate a cash working capital allowance.

Elements of P.U.C Subst. R. 25.231(c)(2)(B)(iii), which are instructive to AE, further define the components of the calculation as:

> (I) Cash working capital for electric utilities shall in no event be greater than one-eighth of total annual operations and maintenance expense, excluding amounts charged operations and maintenance expense for materials, supplies, fuel, and prepayments.
>
> (III) Operations and maintenance expense does not include depreciation, other taxes, or Federal income taxes, for purposes of subclauses (I), (II), and (V) of this clause.

In the 2012 Rate Review, AE's Working Capital Reserve included O&M expenses, less Net Power Supply Cost, consistent with P.U.C Subst. R. 25.231(c)(2)(B)(iii).

Recommendation

With respect to current regulation, and potential future review by the PUCT, NewGen recommends the following.

- Based on PUCT precedent established with MOUs successfully filing transmission cost of service applications, NewGen believes that the cash basis method of establishing rates, including provisions for funding reserves, is acceptable to the PUCT given proper justification.
- NewGen recommends AE continue to remove Net Power Supply Cost from O&M for establishing the funding levels for the Working Capital Reserve, to remain consistent with PUCT guidelines.

Appendix 1
AUSTIN ENERGY FINANCIAL POLICIES

MEMORANDUM

TO: Mayor and Council Members

CC: Marc A. Ott, City Manager

FROM: Larry Weis, General Manager

DATE: March 24, 2015

SUBJECT: Cash and Reserve Policy

In preparation for the upcoming Austin Energy Utility Oversight Committee meeting, please see the attached cash and reserve policies for Austin Energy, including current balances.

Description	Policy #	Date Adopted	Date Revised	Target Amount	Historical Balances (audited)	FY14 Actuals (unaudited)	Feb 28, 2015 (unaudited)	FY15 Target Amount [1]	# Years to Replenish per Financial Policy	Uses	Funding Source
Operating Cash	**11**	FY1989	N/A	Maintain 45 days of budgeted operations and maintenance expense, less fuel.	FY10 = $133,593,652 FY11 = $70,768,039 FY12 = $48,668,471 FY13 = $119,230,805	$150,799,844	$187,515,594	$68,055,905	Not specified.	Working capital for daily operations.	Revenue Requirements.
Repair and Replacement	**15**	FY2002	FY2012	Maximum of 50% of previous year's electric utility depreciation expense.	FY10 = $64,071 FY11 = $64,071 FY12 = $64,071 FY13 = $64,071	$64,071	$64,071	$76,225,000	Not specified.	Providing extensions, additions, replacements and improvements to the Electric System. Transfer of $7,650,000 in FY2004 to Austin Energy's Operating Fund to fund the first two years of Holly Power Plant decommissioning costs. Transfers of $30,000,000 in FY2008 and $35,000,000 in FY2009 were made to the Austin Energy Operating Fund for its Capital Improvements Program to fund additional generation peaking capacity at the Sand Hill Energy Center. Transfers were in the Approved Budget.	Revenue Requirements.
Non-nuclear decommissioning[2]	**21**	FY2002	N/A	Funding will be set aside over a minimum of four (4) years prior to the expected plant closure.	FY10 = $14,873,603 FY11 = $19,541,193 FY12 = $15,093,817 FY13 = $11,490,144	$8,138,072	$7,741,590	$15,582,437	Funding will be set aside over a minimum of four (4) years prior to the expected	Fund plant retirement and decommissioning. Used to fund the cost of decommissioning the Holly Power Plant. FY15 Target includes remaining cost of	Revenue Requirements.

[1] Assumes Operating Cash in excess of the FY15 Target Amount is transferred to the other Reserve Funds
[2] Includes funding for on-going decommissioning of Holly Plant from FY10 through FY15 and for the first year allocation for Decker Plant in FY15

Description	Policy #	Date Adopted	Date Revised	Target Amount	Historical Balances (audited)	FY14 Actuals (unaudited)	Feb 28, 2015 (unaudited)	FY15 Target Amount [1]	# Years to Replenish per Financial Policy	Uses	Funding Source
									plant closure.	decommissioning Holly and 25% cost of decommissioning Decker steam units.	
Strategic Reserve – Emergency	**16**	FY1997	FY2002	Minimum of 60 days of non-power supply operating requirements.	FY10 = $66,385,723 FY11 = $68,122,357 FY12 = $69,484,824 FY13 = $80,508,399	$80,765,286	$90,741,207	$90,741,207	Not specified.	Used as a last resort to provide funding in the event of an unanticipated or unforeseen extraordinary need of an emergency nature, such as costs related to a natural disaster, emergency or unexpected costs created by Federal or State legislation. The Emergency Reserve shall be used only after the Contingency Reserve has been exhausted.	Revenue Requirements.
Strategic Reserve – Contingency	**16**	FY1997	FY2002	Maximum of 60 days of non-power supply operating requirements.	FY10 = $66,385,723 FY11 = $68,122,357 FY12 = $46,997,974 FY13 = $25,487,620	$25,811,754	$16,586,412	$90,741,207	Balance will be replenished to the targeted amount within two (2) years.	Used for unanticipated or unforeseen events that reduce revenue or increase obligations such as extended unplanned plant outages, insurance deductibles, unexpected costs created by Federal or State legislation, and liquidity support for unexpected changes in fuel costs or purchased power which stabilizes fuel rates for our customers.	Revenue Requirements.
Strategic Reserve – Rate Stabilization. Previously named Competitive Reserve.	**16**	FY1997	FY2012	Balance shall not exceed 90 days of net power supply costs.	FY10 = $8,923,801 FY11 = $4,283,995 FY12 = $0 FY13 = $0	$0	$0	$126,379,024	Not specified.	Replaced the Strategic Reserve – Competitive Portion Uses include: (1) deferring or minimizing future rate increases, (2) new generation capacity construction and acquisition costs and/or (3) balancing of annual power supply costs (net power supply/energy settlement cost).	Revenue Requirements.
GRAND TOTAL					FY10 = $290,226,573 FY11 = $230,902,012 FY12 = $180,309,157 FY13 = $236,781,039	$265,579,027	$302,648,874	$467,724,780			

Financial Policy #	Financial Policy	History of Revisions
11	Austin Energy shall maintain operating cash equivalent to 45 days of budgeted operations and maintenance expense, less fuel.	Policy initially adopted June 15, 1989.
15	A Repair and Replacement Fund shall be created and established. Moneys on deposit in the Repair and Replacement Fund shall be used for providing extensions, additions, replacements and improvements to the Electric System. Net revenues available after meeting the General Fund Transfer, capital investment (equity contributions from current revenues) and 45 days of working capital may be deposited in the Repair and Replacement Fund. The targeted balance shall not exceed 50% of the previous year's electric utility depreciation expense which is at a level necessary to keep the electric system in good operating condition or to prevent a loss of revenues.	Added in FY2002. FY2012 Revision – Added target for reserve. The targeted balance shall not exceed 50% of the previous year's electric utility depreciation expense which is at a level necessary to keep the electric system in good operating condition or to prevent a loss of revenues. Transfer of $7,650,000 in FY2004 to Austin Energy's Operating Fund to fund the first two years of Holly Power Plant decommissioning costs. Transfers of $30,000,000 in FY2008 and $35,000,000 in FY2009 were made to the Austin Energy Operating Fund for its Capital Improvements Program to fund additional generation peaking capacity at the Sand Hill Energy Center. Transfers were in the Approved Budget.
21	A Non-Nuclear Plant Decommissioning Fund shall be established to fund plant retirement. The amount set aside will be based on a decommissioning study of the plant site. Funding will be set aside over a minimum of four (4) years prior to the expected plant closure.	Policy initially adopted FYY2004. Holly Power Plant was the first facility affected by this policy. A decommissioning cost study was completed in 2003 and funding began in the FY 2005 budget.

Financial Policy #	Financial Policy	History of Revisions
16	A fund named Strategic Reserve Fund shall be created and established, replacing the Debt Management Fund. It will have three components: • An Emergency Reserve with a minimum of 60 days of non-power supply operating requirements. • Up to a maximum of 60 days additional non-power supply operating requirements set aside as a Contingency Reserve. • Any additional funds over the maximum 90 days of non-power supply operating requirements may be set aside in a Competitive Reserve. The Emergency Reserve shall only be used as a last resort to provide funding in the event of an unanticipated or unforeseen extraordinary need of an emergency nature, such as costs related to a natural disaster, emergency or unexpected costs created by Federal or State legislation. The Emergency Reserve shall be used only after the Contingency Reserve has been exhausted. The Contingency Reserve shall be used for unanticipated or unforeseen events that reduce revenue or increase obligations such as extended unplanned plant outages, insurance deductibles, unexpected costs created by Federal or State legislation, and liquidity support for unexpected changes in fuel costs or purchased power which stabilizes fuel rates for our customers. In the event any portion of the Contingency Reserve is used, the balance will be replenished to the targeted amount within two (2) years. A Rate Stabilization Reserve shall be created and established, replacing the Competitive Reserve in FY 2012, for the purpose of stabilizing electric utility rates in future periods. The Rate Stabilization Reserve may provide funding for: (1) deferring or minimizing future rate increases, (2) new generation capacity construction and acquisition costs and/or (3) balancing of annual power supply costs (net power supply/energy settlement cost). The balance shall not exceed 90 days of net power supply costs. Funding may be provided from net revenue available after meeting the General Fund Transfer, capital investment (equity contributions from current revenue), Repair and Replacement Fund, and 45 days of working capital.	FY1997 – 12/12/1996 Council Resolution to establish a strategic policy necessary to ensure the competitive position and to preserve the value of the Electric Utility. The City Manager will provide a detailed analysis of the utility's projected competitive position and recommend, based on this analysis, the annual allocation of utility revenue to its debt defeasance fund. FY2002 – Added Policy for Debt Management Fund. A Debt Management Fund shall be created and established. Net revenues available after meeting the General Fund Transfer, capital investment (equity contributions from current revenues, Repair and Replacement Fund, and 45 days of working capital may be deposited in the Debt Management Fund. Moneys in the Debt Management Fund will be sued to improve the competitive position of the Electric Utility including, but not limited to, funding capital needs in lieu of debt issuance reduction of outstanding debt, improving the debt to capital ratio, and other competitive stratifies such as rate reductions and new technologies. FY2004 – Policy change to rename the Debt Management Fund as the Strategic Reserve and established the Emergency Reserve, Contingency Reserve and Competitive Reserve. FY2012 Revision - A Rate Stabilization Reserve shall be created and established, replacing the Competitive Reserve in FY 2012, for the purpose of stabilizing electric utility rates in future periods. The Rate Stabilization Reserve may provide funding for: (1) deferring or minimizing future rate increases, (2) new generation capacity construction and acquisition costs and/or (3) balancing of annual power supply costs (net power supply/energy settlement cost). The balance shall not exceed 90 days of net power supply costs. The Rate Stabilization Reserve replaced the Competitive Reserve portion of the Strategic Reserve which was fully depleted.

Financial Policies — 2014-15

Policy	Current Status
Austin Energy Financial Policies	
1. The term of debt generally shall not exceed the useful life of the asset, and in no case shall the term exceed 30 years.	In compliance.
2. Capitalized interest shall only be considered during the construction phase of a new facility if the construction period exceeds 7 years. The time frame for capitalizing interest may be 3 years but not more than 5 years. Council approval shall be obtained before proceeding with a financing that includes capitalized interest.	N/A
3. Principal repayment delays shall be 1 to 3 years, but shall not exceed 5 years.	In compliance.
4. Austin Energy shall maintain either bond insurance policies or surety bonds issued by highly rated ("AAA") bond insurance companies or a funded debt service reserve or a combination of both for its existing revenue bond issues, in accordance with the Combined Utility Systems Revenue Bond Covenant.	In compliance.
5. A debt service reserve fund shall not be required to be established or maintained for the Parity Electric System Obligations so long as the "Pledged Net Revenues" of the System remaining after deducting the amounts expended for the Annual Debt Service Requirements for Prior First Lien and Prior Subordinate Lien Obligations is equal to or exceeds one hundred fifty per cent (150%) of the Annual Debt Service Requirements of the Parity Electric Utility Obligations. If the "Pledged Net Revenues" do not equal or exceed one hundred fifty per cent (150%) of the Annual Debt Service Requirements of the Parity Electric Utility Obligations, then a debt service reserve fund shall be established and maintained in accordance with the Supplemental Ordinance for such Parity Electric System Obligations.	In compliance.
6. Debt service coverage of a minimum of 2.0x shall be targeted for the Electric Utility Bonds. All short-term debt, including commercial paper, and non-revenue obligations will be included at 1.0x.	In compliance. Debt service coverage (DSC) for the FY 2014-15 Budget is 3.21x.
7. Short-term debt, including commercial paper, shall be used when authorized for interim financing of capital projects and fuel and materials inventories. The term of short-term debt will not exceed 5 years. Both Tax-Exempt and Taxable commercial paper may be issued in order to comply with the Internal Revenue Service Rules and Regulations applicable to Austin Energy. Total short-term debt shall generally not exceed 20% of outstanding long-term debt.	In compliance.
8. Commercial paper may be used to finance capital improvements required for normal business operation for Electric System additions, extensions, and improvements or improvements to comply with local, state and federal mandates or regulations. However, this shall not apply to new nuclear generation units or conventional coal generation units.	In compliance.

Financial Policies — 2014-15

Policy	Current Status
Commercial paper will be converted to refunding bonds when dictated by economic and business conditions. Both Tax-Exempt and Taxable refunding bonds may be issued in order to comply with the Internal Revenue Service Rules and Regulations applicable to Austin Energy. Commercial paper may be used to finance voter approved revenue bond projects before the commercial paper is converted to refunding bonds.	
9. Ongoing routine, preventive maintenance should be funded on a pay-as-you-go basis.	In compliance.
10. Austin Energy shall maintain a minimum quick ratio of 1.50 (current assets less inventory divided by current liabilities). The source of this information should be the Comprehensive Annual Financial Report.	In compliance.
11. Austin Energy shall maintain operating cash equivalent to 45 days of budgeted operations and maintenance expense, less fuel.	In compliance
12. Net Revenue generated by Austin Energy shall be used for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies, and other Austin Energy requirements such as working capital.	In compliance.
13. The General Fund transfer shall not exceed 12% of Austin Energy three-year average revenues, calculated using the current year estimate and the previous two years' actual revenues from the City's Comprehensive Annual Financial Report.	In compliance.
14. Capital projects should be financed through a combination of cash, referred to as pay-as-you-go financing (equity contributions from current revenues), and debt. An equity contribution ratio between 35% and 60% is desirable.	In compliance.
15. A Repair and Replacement Fund shall be created and established. Moneys on deposit in the Repair and Replacement Fund shall be used for providing extensions, additions, replacements and improvements to the Electric System. Net revenues available after meeting the General Fund Transfer, capital investment (equity contributions from current revenues) and 45 days of working capital may be deposited in the Repair and Replacement Fund. The targeted balance shall not exceed 50% of the previous year's electric utility depreciation expense, which is at a level necessary to keep the electric system in good operating condition or to prevent a loss of revenues.	In compliance.
16. A Strategic Reserve Fund shall be created and established, replacing the Debt Management Fund. It will have three components: · An Emergency Reserve with a minimum of 60 days of non-power supply operating requirements. · Up to a maximum of 60 days additional non-power supply operating requirements set aside as a Contingency Reserve.	In Compliance by the end of FY 2014-15.

Financial Policies — 2014-15

Policy	Current Status

- Any additional funds over the maximum 120 days of non-power supply operating requirements may be set aside in a Rate Stabilization Reserve.

  The Emergency Reserve shall only be used as a last resort to provide funding in the event of an unanticipated or unforeseen extraordinary need of an emergency nature, such as costs related to a natural disaster, emergency or unexpected costs created by Federal or State legislation. The Emergency Reserve shall be used only after the Contingency Reserve has been exhausted.

  The Contingency Reserve shall be used for unanticipated or unforeseen events that reduce revenue or increase obligations such as extended unplanned plant outages, insurance deductibles, unexpected costs created by Federal or State legislation, and liquidity support for unexpected changes in fuel costs or purchased power which stabilizes fuel rates for Austin Energy customers.

  In the event any portion of the Contingency Reserve is used, the balance will be replenished to the targeted amount within two (2) years.

  A Rate Stabilization Reserve shall be created and established, replacing the Competitive Reserve in FY 2011-12, for the purpose of stabilizing electric utility rates in future periods. The Rate Stabilization Reserve may provide funding for: (1) deferring or minimizing future rate increases, (2) new generation capacity construction and acquisition costs and (3) balancing of annual power supply costs (net power supply/energy settlement cost). The balance shall not exceed 90 days of net power supply costs.

  Funding may be provided from net revenue available after meeting the General Fund Transfer, capital investment (equity contributions from current revenue), Repair and Replacement Fund, and 45 days of working capital.

17. Electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to support (1) the full cost (direct and indirect) of operations including depreciation, (2) debt service, (3) General Fund transfer, (4) equity funding of capital investments, (5) requisite deposits of all reserve accounts, (6) sufficient annual debt service requirements of the Parity Electric Utility Obligations and other bond covenant requirements, if applicable, and (7) any other current obligations. In addition, Austin Energy may recommend to Council in the budget directing excess net revenues for General Fund transfers, capital investment, repair and replacement, debt management, competitive strategies and other Austin Energy requirements such as working capital. — In compliance.

    In addition to these requirements, electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to ensure a minimum debt service coverage of 2.0x on electric utility revenue bonds.

Financial Policies — 2014-15

Policy	Current Status
A rate adequacy review shall be completed every five years, at a minimum, through performing a cost of service study.	
18. A decommissioning trust shall be established external to the City to hold the proceeds for moneys collected for the purpose of decommissioning the South Texas Nuclear Project. An external investment manager may be hired to administer the trust investments.	In compliance.
19. The master ordinance of the Parity Electric System Obligations does not require a debt service reserve fund. Austin Energy will maintain a minimum of unrestricted cash on hand equal to six months debt service for the then outstanding Parity Electric System Obligations.	In compliance.
20. Current revenue, which does not include the beginning balance, will be sufficient to support current expenditures (defined as “structural balance”). However, if projected revenue in future years is not sufficient to support projected requirements, ending balance may be budgeted to achieve structural balance.	In compliance.
21. A Non-Nuclear Plant Decommissioning Fund shall be established to fund plant retirement. The amount set aside will be based on a decommissioning study of the plant site. Funding will be set aside over a minimum of four (4) years prior to the expected plant closure.	In compliance.

Appendix 2
NON-NUCLEAR DECOMMISSIONING COST STUDY

FINAL REPORT | July 27, 2015

NON-NUCLEAR DECOMMISSIONING COST STUDY

Austin Energy
Austin, Texas

PREPARED BY:

NewGen Strategies & Solutions

ECONOMICS STRATEGY STAKEHOLDERS SUSTAINABILITY www.newgenstrategies.net

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Non-Nuclear Decommissioning Cost Study

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Non-Nuclear Decommissioning Cost

Introduction and Overview

At the request of Austin Energy ("AE"), NewGen Strategies and Solutions, LLC ("NewGen") and its subconsultants, AECOM Technical Services, Inc. ("AECOM") and Encotech Engineering Consultants, Inc. ("Encotech"), prepared decommissioning and demolition cost estimates for Decker Creek Power Station ("Decker") Units 1 and 2, AE's ownership share in Fayette Power Project Units 1 and 2 and associated common facilities, and the Sand Hill Energy Center.

This report summarizes the results of the decommissioning cost study. More detailed information is provided in the following appendices to this report.

- Appendix A: Decker Creek Power Station Plant Decommissioning Cost Estimate (Detailed Site Specific Estimate)
- Appendix B: Benchmarking Cost Estimate for Fayette Power Project and Sand Hill Energy Center
- Appendix C: Survey of Public Utility Commission Proceedings Regarding Non-Nuclear Decommissioning Costs

Decker Creek Units 1 and 2

As requested by AE, the scope of the Decker decommissioning and demolition cost estimate includes Decker Units 1 and 2 and other buildings and equipment delineated in the AECOM report provided in Appendix A. Decker Units 1 and 2 are two gas-fired steam turbine generating units constructed between 1967 and 1971 with a capacity of 321 megawatts ("MW") and 405 MW, respectively. The scope of work for the Decker decommissioning cost study does not include the four gas turbines at Decker.

The Decker decommissioning cost estimate is a detailed engineering, site specific cost estimate. The cost estimate was prepared by an AECOM team consisting of cost estimators, hazardous materials abatement experts, and personnel previously involved in the decommissioning of similar plants. Encotech was utilized to provide the concrete quantities for disposal and the steel quantities for scrap value credit. The project team made two site inspections of the Decker Creek Power Station for the purpose of identifying the buildings and equipment to be included in the decommissioning cost estimate.

During the development of the cost estimate, AECOM coordinated with AE to define the scope of work and associated assumptions in preparing the cost estimate. The agreed upon assumptions are discussed in more detail in the AECOM report provided in Appendix A. Some of the key assumptions are:

- Hazardous materials surveys and quantity calculations have not been completed for Decker. Because the Holly Power Plant and Decker Units 1 and 2 were constructed in the same time period and are similar in size, actual quantities of hazardous materials for the Holly Power Plant Decommissioning Project[1] were used for the Decker cost estimate.

- The Decker decommissioning cost estimate assumes removal of all concrete, piping, ducts, etc. to a depth of five feet below ground surface. Any items deeper will be left in place with the exception of the subsurface fuel oil lines and the 4160 duct banks. The cost to fully remove the subsurface fuel oil lines and the 4160 duct banks, regardless of depth, was included in the estimate based on input provided by AE.
- Allowances for the scrap value of steel, copper, and aluminum are included in the cost estimate. It is assumed that all equipment to be decommissioned have no resale value and therefore it was assumed the equipment will be recycled for scrap value.
- The decommissioning cost estimate includes costs to restore the decommissioned areas. Site restoration activities include backfilling all excavated underground duct banks, pits, and foundations with clean off-site fill after removal. The estimate assumes the final restored surface will consist of crushed stone in the turbine and boiler building areas and topsoil and seeding at the location of the fuel oil storage tanks. Restoration activities include leveling the earthen berms surrounding the two fuel oil tanks.

AECOM prepared a risk register in accordance with the AACE International Recommended Practice No. 40R-08 “Contingency Estimating” to quantitatively evaluate the potential impact and probability of occurrence for areas of risk. The overall contingency allowance for the decommissioning cost estimate was determined based on the sum of the allowances for each item in the risk register. The overall contingency allowance included in the estimated decommissioning cost is equal to 16.1 percent.

To estimate the total costs associated with the decommissioning of Decker Units 1 and 2, AECOM solicited input from AE on owner’s costs from the Holly Power Plant, a similar power plant decommissioning project recently completed. Owner’s costs include costs incurred by AE staff before and during the decommissioning process such as de-oiling, de-energizing, and isolating equipment before dismantlement activities begin; engineering and permitting costs; and construction management and oversight costs. In addition, AECOM estimated a range of costs for soil and groundwater remediation costs based on the Holly Power Plant decommissioning. The owner’s costs provided by AE were scaled and applied as appropriate to Decker Units 1 and 2, as well as Fayette Units 1 and 2 and the Sand Hill Energy Center discussed later in this report.

Table 1 shows a summary of the decommissioning cost estimate for Decker Creek Units 1 and 2. All costs shown are in 2015 dollars.

[1] Holly Power Plant Decommissioning Project, *Building Decommissioning Report*, prepared by Weston Solutions, Inc., April 2014.

Table 1
Decommissioning Cost Estimate
Decker Creek Units 1 and 2

Task	Description	Estimated Costs
01	Contractor Field OH and General Conditions	$ [redacted]
02	Mobilization	[redacted]
03	Environmental Controls	[redacted]
04	Hazardous Materials Abatement Allowances	[redacted]
05	Plant Equipment & Piping Decommissioning & Cleaning	[redacted]
06	Demolition	[redacted]
07	Site Restoration	[redacted]
08	Recycling & Salvaging	[redacted]
09	Demobilization	[redacted]
	Contingency	[redacted]
	Total Detailed Costs for Demolition	$ 11,131,374

Other Estimated Project Costs

Task	Low Range Estimate	High Range Estimate
De-oil, De-energize and Isolate Equipment	$ [redacted]	$ [redacted]
Engineering/Permitting Costs (20%-30%)	[redacted]	[redacted]
Construction Management/Oversight Costs ($250,000 to $400,000 per month)	[redacted]	[redacted]
Soil and Groundwater Remediation	[redacted]	[redacted]
Total Project Costs	$ 18,551,374	$ 27,721,374

Source: Appendix A, AECOM report, Decker Creek Power Station, and Plant Decommissioning Cost Estimate. See AECOM report for description of assumptions and analysis used to develop cost estimates.

Fayette Power Project and Sand Hill Energy Center

For the Fayette Power Project and Sand Hill Energy Center, AE requested that the decommissioning cost estimate be developed using a benchmark approach based on scaled costs from actual decommissioning costs for similar power plants. AECOM's letter report describing the Benchmark Cost Estimate for Fayette Power Project and Sand Hill Energy Center is provided in Appendix B.

The Fayette Power Project is a 1,625 MW coal-fired power plant that was constructed between 1979 and 1980. AE shares 50 percent ownership of Units 1 and 2 at the Fayette Power Project with the Lower Colorado River Authority. AE has no ownership interest in Unit 3 at the Fayette Power Project. For the Fayette Power Project, only Fayette Units 1 and 2 (590 MW each) and the common plant for Fayette Units 1, 2, and 3 identified in the equipment list in Appendix B were included in the Fayette Power Project benchmark cost estimate. The percentage of ownership applied to the benchmark cost estimate is 50 percent for Units 1 and 2 and 36 percent for the common items for Units 1, 2, and 3 as described in Appendix B.

The Sand Hill Energy Center consists of six 45 MW gas turbines and a 300 MW natural gas, combined cycle power plant that were constructed between 2001 and 2010. AE owns 100 percent of the Sand Hill Energy Center; therefore, all the equipment listed in Appendix B was included in the benchmark estimate.

For the benchmark estimates, AECOM identified major decommissioning tasks for the Fayette Power Project and Sand Hill Energy Center. The cost estimates for each major task were prepared by scaling on a dollar per kilowatt ("$/kW") basis from decommissioning costs from similar power plants. In addition, AECOM incorporated available plant specific information, including equipment and building lists, site layouts, and the potential presence of hazardous materials based on the age of the plant.

To estimate the total costs associated with the decommissioning of the Fayette Power Project and Sand Hill Energy Center, AECOM used data provided by AE on owner's costs from the Holly Power Plant decommissioning to estimate owner's costs for Fayette Units 1 and 2 and the Sand Hill Energy Center. The actual owner's costs provided by AE were scaled and used to estimate owner's costs for the benchmark estimates.

Tables 2 and 3 present the benchmark decommissioning cost estimates for AE's ownership share in the Fayette Power Project and the Sand Hill Energy Center, respectively. See AECOM's letter report in Appendix B for the equipment lists and assumptions used in the development of the benchmark cost estimates.

Table 2
Benchmark Decommissioning Cost Estimate
Fayette Power Project

Task	Description	Total Project Cost: Low Range Estimate	Total Project Cost: High Range Estimate
01	Contractor Field OH and General Conditions	$ [redacted]	$ [redacted]
02	Mobilization	[redacted]	[redacted]
03	Environmental Controls	[redacted]	[redacted]
04	Hazardous Materials Abatement	[redacted]	[redacted]
05	Plant Equipment & Piping Decommissioning & Cleaning	[redacted]	[redacted]
06	Demolition	[redacted]	[redacted]
07	Site Restoration	[redacted]	[redacted]
08	Recycling & Salvaging	[redacted]	[redacted]
09	Demobilization	[redacted]	[redacted]
	Contingency (30%)	[redacted]	[redacted]
	Demolition Subtotal Costs	$ 20,150,000	$ 34,260,000

Other Estimated Project Costs

	Low Range Estimate	High Range Estimate
De-oil, De-energize and Isolate Equipment	$ [redacted]	$ [redacted]
Engineering/Permitting Costs (15%-25%)	[redacted]	[redacted]
Construction Management/Oversight Costs ($250,000 to $400,000 per month)	[redacted]	[redacted]
Soil and Groundwater Remediation	[redacted]	[redacted]
Total Project Cost Estimate:	$ 37,320,000	$ 68,560,000
AE 50% Ownership (Units 1 and 2) and 36% (Common Areas)	$ 15,780,000	$ 29,590,000

Source: Appendix B, AECOM letter report, and Benchmarking Cost Estimate for Fayette Power Project and Sand Hill Energy Center. See AECOM letter report for description of assumptions and analysis used to develop cost estimates.

Table 3
Benchmark Decommissioning Cost Estimate
Sand Hill Energy Center

Task	Description	Total Project Cost Low Range Estimate	Total Project Cost High Range Estimate
01	Contractor Field OH and General Conditions	$ [redacted]	$ [redacted]
02	Mobilization	[redacted]	[redacted]
03	Environmental Controls	[redacted]	[redacted]
04	Hazardous Materials Abatement	[redacted]	[redacted]
05	Plant Equipment & Piping Decommissioning & Cleaning	[redacted]	[redacted]
06	Demolition	[redacted]	[redacted]
07	Site Restoration	[redacted]	[redacted]
08	Recycling & Salvaging	[redacted]	[redacted]
09	Demobilization	[redacted]	[redacted]
	Contingency (30%)	[redacted]	[redacted]
	Demolition Subtotal Costs	$ 5,716,000	$ 10,382,000

Other Estimated Project Costs

Description	Low Range Estimate	High Range Estimate
De-oil, De-energize and Isolate Equipment	$ [redacted]	$ [redacted]
Engineering/Permitting Costs (20%-30%)	[redacted]	[redacted]
Construction Management/Oversight Costs ($250,000 to $400,000 per month)	[redacted]	[redacted]
Soil and Groundwater Remediation	[redacted]	[redacted]
Total Project Costs	$ 11,856,000	$ 22,082,000

Source: Appendix B, AECOM letter report, and Benchmarking Cost Estimate for Fayette Power Project and Sand Hill Energy Center. See AECOM letter report for description of assumptions and analysis used to develop cost estimates.

Public Utility Commission Data Regarding Non-Nuclear Decommissioning Costs

NewGen researched utility rate case filings and public utility commission ("PUC") orders regarding non-nuclear decommissioning costs used by other utilities. Our analysis of PUC decommissioning cost data included a review of utility filings and commission orders from Arizona, Arkansas, Colorado, Florida, Georgia, Indiana, Louisiana, Nevada, New Mexico, and Texas. The detailed data is provided in Appendix C.[2] Table 4 shows the median and mean decommissioning cost requested by utilities and the median and mean decommissioning cost

[2] Appendix C is an update of data presented in SOAH Docket No. 473-13-0935 and Public Utility Commission of Texas Docket No. 40627 on behalf of AE in the Rebuttal Testimony of Nancy Heller Hughes.

approved by the PUCs on a $/kW basis. Because some rate cases are still in progress, the number of data points represented in the "Approved Average" is less than the "Requested Average."

Table 4
Summary of PUC Rate Cases
Average Non-Nuclear Decommissioning Costs

Coal-Fired Steam $/kW		
	Approved	Requested
Median	$36.15	$47.99
Mean	$39.45	$74.31
Std. Dev. Above Mean	$69.19	$132.68
Std. Dev. Below Mean	$9.70	$15.95
Sample Size	19	27

Gas-Fired Steam $/kW		
	Approved	Requested
Median	$20.40	$23.74
Mean	$17.40	$33.09
Std. Dev. Above Mean	$28.57	$63.76
Std. Dev. Below Mean	$6.23	$2.43
Sample Size	8	14

Gas Turbine $/kW		
	Approved	Requested
Median	$11.02	$29.11
Mean	$19.61	$51.18
Std. Dev. Above Mean	$39.80	$112.22
Std. Dev. Below Mean	($0.59)	($9.87)
Sample Size	5	8

Combined Cycle $/kW		
	Approved	Requested
Median	$17.24	$19.98
Mean	$20.56	$21.26
Std. Dev. Above Mean	$33.14	$33.73
Std. Dev. Below Mean	$7.99	$8.80
Sample Size	15	16

Source: Appendix C, utility rate filings and PUC decisions.

The PUC data shown in Table 4 includes decommissioning cost estimates approved by regulatory commissions or requested by utilities in 2009 through 2014. In some cases, NewGen was able to obtain a copy of the site specific dismantlement study filed by a utility; however, more often, only the results of the studies or approved decommissioning costs are available.

As shown in Table 4, there is a wide range of decommissioning cost estimates on a $/kW basis for each type of power plant. For example, for coal-fired steam plants, the average (mean) commission-approved decommissioning cost is equal to $39.45/kW, with costs ranging one standard deviation below and above the mean from $9.70/kW to $69.19/kW. Costs will vary depending on the scope of the decommissioning activities, the amount of salvage value included in the cost estimate, the extent of soil and groundwater remediation activities, and owner's costs. A breakdown of these costs is usually not available from the PUC data unless the dismantlement cost study is available.

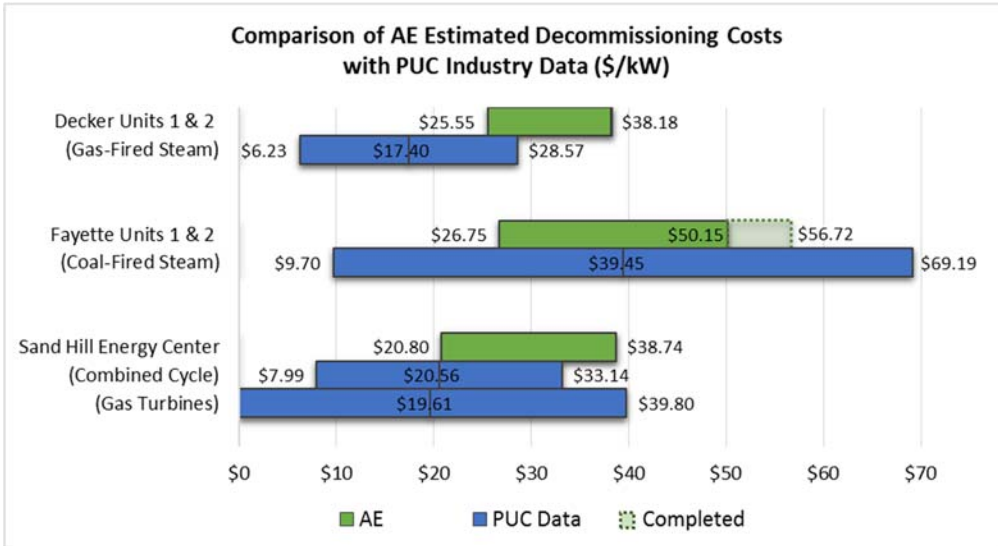
Table 5 shows the estimated decommissioning costs for Decker Units 1 and 2, Fayette Units 1 and 2, and Sand Hill Energy Center expressed on a dollars per kW basis based on the data conveyed in Tables 1, 2, and 3. Note the range listed for Fayette Units 1 and 2 does not include work already completed (including the closure of an ash pond).

Table 5
Estimated Non-Nuclear Decommissioning Costs
($/kW)

Generating Unit	Type of Plant	Capacity (MW)	Retirement Year	Decommissioning Cost ($/kW)	
				Low	High
Decker Units 1 and 2	Gas-fired steam	726	2018	$25.55	$38.18
Fayette Units 1 and 2*	Coal-fired steam	590	2025	$26.75	$50.15
Sand Hill Energy Center	Combined Cycle and Gas Turbines	570	2030	$20.80	$38.74

* The 590 MW capacity reflects AE's ownership share in the two units, rather than the total capacity of the units.

Figure 1 shows a comparison of the decommissioning cost estimates prepared by AECOM for Decker Units 1 and 2, Fayette Units 1 and 2, and the Sand Hill Energy Center with the PUC industry data presented in Table 4 by type of plant.



Source: Tables 4 and 5

Figure 1
Comparison of AE Estimated Decommissioning Costs
with PUC Industry Data ($/kW)

Figure 1 shows the range of estimated decommissioning costs for Decker Units 1 and 2 and the Sand Hill Energy Center are at or above the high end of the range of decommissioning costs approved by PUCs. This is primarily due to the level of owner's costs that are included in the decommissioning cost estimates for AE's generating units.

AECOM utilized data provided by AE regarding owner's costs from the Holly Power Plant decommissioning to estimate the owner's costs for Decker Units 1 and 2, Fayette Units 1 and 2, and the Sand Hill Energy Center. The level of owner's costs will depend on how involved the utility is in the decommissioning project. Since AE tends to be very involved in its projects, we would expect the owner's costs to be at the higher end of the range of PUC industry data than the lower end. Relying on data from the Holly Power Plant decommissioning is a reasonable way to estimate AE owner's costs on future decommissioning projects.

Figure 1 also shows the range of estimated decommissioning costs for Fayette Units 1 and 2, including decommissioning work already completed, which is in the middle to higher end of the range of decommissioning costs approved by PUCs. The completed work identified in Figure 1 for Fayette Units 1 and 2 is equal to AE's 50 percent share of remediation costs for one ash pond that has been closed. If the cost of the ash pond closure ($6.57 per kW) is added back to the owner's costs, the cost to decommission Fayette Units 1 and 2 is in the range of approximately $33/kW to $57/kW.

Non-Nuclear Decommissioning Reserve

AE Financial Policy No. 21, which established the Non-Nuclear Decommission Reserve, states that funding for the decommissioning of a plant will be set aside over a minimum of four years prior to the expected plant closure. The funds in the Non-Nuclear Decommissioning Reserve are restricted to use for generation decommissioning costs, but not associated with a particular plant or unit. The Non-Nuclear Decommissioning Reserve was established in 2002 to accumulate funds for the Holly Power Plant decommissioning.

Recommendations

NewGen recommends AE take the following steps to begin accumulating funds in the Non-Nuclear Decommissioning Reserve to pay to decommission Decker Units 1 and 2, Fayette Units 1 and 2, and the Sand Hill Energy Center in the future:

- Given the near-term goal of retiring Decker Units 1 and 2 by fiscal year 2018, and AE's financial policy requiring that funds be set aside over a minimum of four years prior to the expected plant closure, NewGen would recommend that AE begin accumulating additional funds in the Non-Nuclear Decommissioning Reserve as soon as practical.
- NewGen recommends targeting the high end of the estimated range of costs for decommissioning Decker Units 1 and 2. Although the Decker decommissioning cost estimate was developed based on a site specific engineering cost estimate, there are still areas of the cost that could represent significant liabilities that need further investigation (e.g., remediation needs). If the cost of decommissioning the Decker units proves to be less than the high end of the estimate, the savings can be applied to the decommissioning of the next plant. Thus, funds set aside in the reserve will be used for their intended purpose, even if they end up not being needed at Decker.
- NewGen also recommends that AE begin accumulating funds in the Non-Nuclear Decommissioning Reserve as soon as practical for the future decommissioning of Fayette Units 1 and 2 and the Sand Hill Energy Center. In doing so, there is better alignment between the customers benefiting from the power plants while they are in service and the customers paying for the eventual dismantlement of the facilities in the future. In addition, the earlier AE starts the process of setting aside funds for each generation unit, the lower the potential rate impact and the more equitable the recovery of these costs.

Appendix A
Decker Creek Power Station
Plant Decommissioning Cost Estimate
(Detailed Site Specific Analysis)

Submitted to
NewGen Strategies & Solutions
3420 Executive Center Drive
Austin, TX 78731

Submitted by
AECOM
400 W. 15th Street,
Suite 600
Austin, TX 78701
July 10, 2015

Decker Creek Power Station
Plant Decommissioning Cost Estimate

Table of Contents

List of Appendices

List of Figures

1 Introduction

This report presents the decommissioning and demolition cost estimate prepared by AECOM Technical Services, Inc. (AECOM) for NewGen Strategies & Solutions for the Austin Energy (AE) Decker Creek Power Station located in Austin, Texas. The Decker Creek Power Station is a 927 megawatt natural gas power plant that was constructed between 1967 and 1978 and initially utilized fuel oil. Units 1 and 2, which were included in the decommissioning scope and cost estimate, have a total capacity of 726 megawatts. A vicinity map depicting the location of the Decker Creek Power Plant Station is provided in Figure 1.

The decommissioning and demolition cost estimate was prepared following AECOM's Estimate Classification System based on the AACE International system to develop a Budget/Authorization/Control (Level 3) estimate. The decommissioning cost estimate was prepared for the removal of the Unit 1 & Unit 2 turbine generator and boiler buildings and supporting structures as well as other buildings and equipment delineated in this report. Encotech Engineering Consultants, a subcontractor to NewGen Strategies & Solutions was utilized to provide the concrete quantities for disposal and the steel quantities for scrap value credit.

2 Cost Estimate

To prepare the cost estimate, AECOM initially completed a desktop review of the drawings and other site files provided by AE on the Decker Creek Power Station. After the desktop review, a site visit was completed with AE personnel so the layout of the individual buildings and equipment to be decommissioned could be observed. During the site visit, the buildings and equipment to be included in the decommissioning cost estimate was discussed in detail with AE personnel.

Based on the desktop review and site visit, a task list was prepared for the decommissioning activities. The list was prepared to provide a general description of each major task to be completed as part of the decommissioning and demolition. The task list served as the basis of the estimate and was used as the work breakdown structure (WBS) for preparing the decommissioning cost estimate.

Once the task list and work breakdown structure (WBS) was developed, the cost estimate was prepared by an AECOM team consisting of cost estimators, hazardous materials abatement experts, and personnel previously involved in the decommissioning of similar power plants. AECOM utilized the SageTimberline Estimating software which is an open conductive (ODBC) system to develop the cost estimate. The software was supplemented with AECOM's developed and maintained database, consisting of over 75,000 items, which was used to provide current pricing and area cost factors. In addition, AECOM solicited input from contractors that we have used in the past to validate some of the key pricing elements.

After the cost estimate was developed, AECOM utilized a risk register to determine an appropriate level of contingency allowance that should be included in the estimate at the task level.

2.1 Desktop Review

As part of the desktop review, AECOM reviewed existing documentation for the Decker Creek Power Station provided by AE. The information reviewed included building construction drawings and floor plans, site plans, and a previous asbestos and hazardous materials inspection report. Note that quantities of hazardous materials, including asbestos containing materials (ACM) are not available for the Decker Creek Power Station. Therefore, as part of the desktop review, AECOM reviewed the quantities of hazardous materials removed and disposed for the Holly Plant which is of a similar age and design as Decker.

2.2 Site Inspection

After completing the desktop review, a site inspection was completed by AECOM of the Decker Creek Power Station on Wednesday, March 18, 2015. AECOM was accompanied by Rogelio Zavala, who is AE's Power System Engineer for the Decker Creek Power Station. During the site inspection, the scope of the buildings and equipment to be included in the decommissioning cost estimate was defined. In addition, AECOM personnel observed the type of construction and configuration of the various portions of the plant and that was used in developing the assumed demolition methods and procedures used in the cost estimate.

A second site inspection was completed by AECOM and Encotech on Friday, April 10, 2015. The second site inspection was to allow Encotech to visually inspect the buildings and equipment to be included in their concrete and steel volume estimates. AECOM and Encotech were accompanied by Steve Wotruba, who is AE's Plant Manager for the Decker Creek Power Station.

2.3 Task List and Work Breakout Structure

Based on the desktop review and site inspections, a task list was prepared for the decommissioning and demolition of the Decker Creek Power Station. The list was prepared to provide a general description of each major task to be completed as part of the decommissioning and demolition activities. The task list served as the basis of the cost estimate and was prepared based on the following information:

- Existing plant documentation;
- Site inspection;
- Identified or potential presence of hazardous materials;
- Decommissioning and demolition approach to:
  - Building/Structures
  - Salvage
  - Scrap
  - Recyclable materials
  - Disposal
- Sequencing approach to:
  - Hazardous materials characterization, abatement, disposal
  - Equipment salvage
  - Building deconstruction
  - Scrap materials
  - Off-site disposal

The following provides the items included and associated assumptions for each of the Level 1 tasks within the WBS. During the development of the cost estimate, AECOM coordinated with AE to define the scope of work and associated assumptions in preparing the detailed cost estimate. The agreed upon assumptions for the detailed cost estimate are discussed below for each task and are provided in Appendix A.

Note that additional owner's costs as discussed in Section 2.4 were included in the overall decommissioning project cost estimate. The owner's costs provided were not prepared as part of the detailed cost estimate. Rather they were scaled from actual costs provided by AE from a similar power plant decommissioning project.

2.3.1 Task 1 - Contractor Field OH & General Conditions

Task 1 contains costs for the contractor to complete the work including:

- Temporary facilities for a project office;
- Power requirements necessary to complete work;
- Water connection and toilet facilities;

- Construction of a truck wash area;
- Obtaining the necessary permits;
- Preparation of work plans and submittals as needed;
- Site security provisions including utilizing temporary chain link fencing and concrete barriers, and;
- On-site project management and safety personnel.

Note that the cost estimate assumes a total project duration of 60 weeks to complete all the decommissioning and demolition activities.

2.3.2 Task 2 - Mobilization

Task 2 includes costs to mobilize to the project site all construction equipment and field personnel.

2.3.3 Task 3 - Environmental Controls

Task 3 contains costs for implementing all the necessary environmental controls to complete the work including:

- Temporary erosion and sediment control features;
- Air monitoring;
- Sampling and testing;
- Dust control provisions, and
- Noise and vibration monitoring.

2.3.4 Task 4 - Hazardous Materials Abatement Allowances

Task 4 includes costs for management of hazardous materials as part of the decommissioning activities including asbestos contain materials (ACM), polychlorinated biphenyls (PCBs), mercury, and hazardous liquids.

Hazardous materials surveys and quantity calculations have not been completed for the Decker Creek Power Station. Because the Holly Power Plant and Decker Creek Power Station were constructed in the same time period and are similar in size, actual quantities of hazardous materials for the Holly Power Plant Decommissioning Project provided in the *Building Decommissioning Report* prepared by Weston Solutions, Inc. dated April 2014 were used for this estimate.

Based on comments provided by AE on our cost estimate assumptions for Decker Creek Power Station, a baseline soil and groundwater investigation was included in the decommissioning cost estimate. The investigation would be used to determine baseline conditions of soil and groundwater after the decommissioning activities are completed so that appropriate future use of the area could be evaluated. Note that soil and groundwater remediation costs, if necessary, have not been included as part of the detailed cost estimate.

2.3.5 Task 5 - Plant Equipment & Piping Decommissioning & Cleaning

Task 5 includes costs for completing the following activities:

- [redacted];

- [redacted];
- [redacted];
- [redacted];
- [redacted].

The cost estimate assumes all piping and equipment to be removed as part of the decommissioning activities will be de-energized, de-oiled, and isolated by Decker Plant personnel. Therefore, the detailed cost estimate only includes costs to verify, flush, and clean residual liquids as needed.

2.3.6 Task 6 - Demolition

Task 6 includes costs to demolish the following items:

- [redacted];
- [redacted];
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

2.3.7 Task 7 - Site Restoration

Task 7 includes costs to restore the decommissioning areas. Site restoration activities include backfilling [redacted] with clean off-site fill after removal. The estimate assumes the final restored surface will consist of crushed stone [redacted] and topsoil and seeding [redacted]. Restoration activities include leveling the earthen berms [redacted].

2.3.8 Task 8 – Recycling and Salvage

Task 8 includes the credit for salvage costs of steel and other metals that will be generated as part of the decommissioning activities. As noted in the detail cost estimate provided in Appendix D, salvage credit value used for steel in this cost estimate was $130/ton.

2.3.9 Task 9 - Demobilization

Task 9 includes costs to demobilize all construction equipment and field personnel from the project site.

2.4 Owner's Costs

To estimate the total costs associated with the decommissioning of the Decker Creek Power Plant, AECOM solicited input from AE on owner's costs from similar projects completed. The owner's costs provided by AE were scaled and applied as appropriate to the Decker Creek Power Plant. Owner's costs are summarized in Section 2.6.

2.5 Risk Register

To assign appropriate contingencies, AECOM prepared a risk register in accordance with AACE International Recommended Practice No. 40R-08 "Contingency Estimating". The risk register allows for a quantitative evaluation of the potential impact of each item catalogued on the risk register by calculating the product of the consequence (i.e., dollars or duration) and the probability of occurrence. The overall contingency allowance for the decommissioning cost estimate was determined based on the sum of the allowances for each item in the risk register.

The risk register prepared for the Decker Creek Power Plant decommissioning activities is presented in Appendix C.

2.6 Summary of Estimate Costs

As indicated in the table below, the estimated detailed decommissioning costs for the Decker Creek Power Plant are $11,131,374. Note that the detailed decommissioning cost estimate is in today's dollars and does not include owner's costs. With the estimated owner's costs included, the total decommissioning costs for the Decker Creek Power Plant are estimated to range between $19,761,374 to $27,321,374. The detailed demolition cost estimate is provided in Appendix D.

Table 1: Summary of Decker Creek Power Plant Decommissioning Cost Estimate

Detailed Decommissioning Cost Estimate

Task	Description	Estimated Costs
1	Contractor Field OH & General Conditions	[redacted]
2	Mobilization	
3	Environmental Controls	
4	Hazardous Materials Abatement Allowances	
5	Plant Equipment & Piping Decommissioning & Cleaning	
6	Demolition	
7	Site Restoration	
8	Recycling & Salvaging	
9	Demobilization	
	Contingency	
TOTAL DETAILED COSTS FOR DEMOLITION		$11,131,374

Other Estimated Project Costs

Task	Low Range Estimate	High Range Estimate
De-oil, De-energize, and Isolate Equipment	[redacted]	[redacted]
Engineering/Permitting Costs (15%-30%)		
Construction Management/Oversight Costs ($200,000 to $400,000 per month)		
Soil and Groundwater Remediation		

Total Project Costs	$18,551,374	$27,721,374

Figures

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Appendix A.
Cost Estimate Scope of Work Assumptions and Basis of Estimate, Decker Power Plant

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Appendix B. Decker Power Plant Decommissioning, Opinion of Material Quantities, ENCOTECH

Decker Power Plant Decommissioning
Opinion of Material Quantities

Prepared for:

AECOM
400 W. 15th Street
Suite 600
Austin, Texas 78701

Prepared by:

Encotech Engineering Consultants
8500 Bluffstone Cove, Suite B-103
Austin, Texas 78759

Firm Registration No. 1141

May 4, 2015

May 4, 2015

Craig Niedermeier, P.E.
Program Manager / Senior Project Manager
AECOM
400 W. 15th Street
Suite 600
Austin, Texas 78701

Re: **Decker Power Plant Decommissioning**
Material Quantities Estimate

Dear Mr. Niedermeier;

Encotech was tasked with the development of quantity estimates for the decommissioning of the Decker Creek Power Station. The quantities developed are broken up into steel scrap and concrete for disposal. Encotech has reviewed the site and structural drawings and has determined the total steel scrap tonnage and concrete volume to be approximately 2563 tons, and 12702 yd^3 respectively.

The following buildings were included in the estimate.

- [redacted]

The focus of this review was the main structural steel and concrete quantities and as such, miscellaneous steel quantities were not determined and are excluded from this report. The quantities are reported by building in Table 1.

Table 1: Steel & Concrete Quantities by Building

Building	Concrete (Cubic Yds)	Structural Steel (Tons)	Reinforcing Steel (Tons)
[redacted]	[redacted]	[redacted]	[redacted]
[redacted] [redacted]	[redacted]	[redacted]	[redacted]
[redacted] [redacted]	[redacted]	[redacted]	[redacted]
[redacted] [redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]-[redacted]	[redacted]	[redacted]	[redacted]
[redacted]-[redacted]	[redacted]	[redacted]	[redacted]
[redacted] [redacted]	[redacted]	[redacted]	[redacted]
Total	12702	2017	546

Calculation Procedure

Encotech reviewed the structural and site drawings to determine the quantity of materials. Values for each building were determined using the following steps:

Concrete

1. The quantity and volume of each type of footing was determined
2. The length of each type of grade beam shown on plan was determined.
3. The volume of concrete in the grade beams was determined based on the cross section of each type of grade beam
4. The areas of the slab at each level were determined from the plans and the volume of each slab was determined based on the section cuts
5. The volume of the concrete columns was determined using the building sections and the details
6. The reinforcement volume was determined by taking the average reinforcement ratio of each type of structure (footing, slab, column, grade beam, etc.) and multiplying buy the total concrete volume of structures in that type. This volume was then multiplied by the density of steel to determine the total reinforcement weight.

Steel

1. The total length of each steel beam/column type was determined based on the structural drawings for each level
2. The weight per linear foot of each beam/column type was multiplied by the total length for that type and the results were summed to determine the total weight of structural steel.

The above procedure was used for each building type except for [redacted]. The structural and concrete drawings for [redacted] were only partially legible so the material quantities for [redacted] were based on the material per square foot of [redacted] This will yield approximate values for bot steel and concrete due to [redacted] designed by the same firm in a relatively short amount of time.

The material values for the [redacted] were determined based on the volume of steel of a ¾" x 30' tall tank with the diameter shown on the plans. The concrete and rebar volumes were based on the plan and details shown on the structural drawings and the reinforcement ratio of the support ring.

The spreadsheets used to determine the material quantities for each building are shown in Appendix A.

Sincerely,

Carl Holiday
Senior Project Manager

Appendix A: Calculation Spreadsheets

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Appendix C.
Decker Creek Power Station Risk Register

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Appendix D
Decker Creek Power Station
Decommissioning Cost Estimate

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Appendix B
Fayette Power Project and Sand Hill Energy Center
Plant Decommissioning Cost Estimate
(Benchmark Analysis)

AECOM
400 West 15th Street, Suite 600
Austin, Texas 78701

512.472.4519 tel
512.472.7519 fax

July 10, 2015

Grant Rabon
NewGen Strategies & Solutions
3409 Executive Center Drive
Suite 128
Austin, Texas 78731

Subject: Benchmarking Cost Estimate
Fayette Power Project and Sand Hill Energy Center

Dear Mr. Rabon,

This letter report presents the benchmark decommissioning and demolition cost estimates prepared by AECOM Technical Services, Inc. (AECOM) for NewGen Strategies & Solutions for the Austin Energy (AE) Fayette Power Project located in La Grange, Texas and the Sand Hill Energy Center located in Austin, Texas. The benchmark estimate approach presented in this letter provides an estimate of the decommissioning costs for the Fayette Power Project and Sand Hill Energy Center based on scaled costs from actual decommissioning costs for similar power plants.

The Fayette Power Project is a 1,625 net megawatt coal fired power plant that was constructed between 1979 and 1980. AE shares 50% ownership of Units 1 and 2 at the Fayette Power Project with the Lower Colorado River Authority (LCRA). Both Units 1 and 2 have a capacity of 590 megawatts or a total capacity of 1,180 megawatts. The Sand Hill Energy Center is a 570 megawatt natural gas, combined cycle power plant that was constructed between 2001 and 2010.

For the benchmark decommissioning cost estimate, AECOM prepared estimates for the following identified major decommissioning tasks for the Fayette Power Project and Sand Hill Energy Center:

1. Contractor Field OH & General Conditions
2. Mobilization
3. Environmental Controls
4. Hazardous Materials Abatement
5. Plant Equipment & Piping Decommissioning & Cleaning
6. Demolition
7. Site Restoration
8. Demobilization

The benchmark estimates at each power plant for each of these identified major tasks were prepared by scaling on a dollar per kilowatt basis from decommissioning costs from similar power plants. In addition, AECOM incorporated available plant specific information including equipment and building lists, site layouts, and potential presence of hazardous materials based on age of the plant. The equipment lists for the Fayette Power Project and Sand Hill Energy Center are listed in Attachment A.

To estimate the total costs associated with the decommissioning of the Fayette Power Project and Sand Hill Energy Center, AECOM solicited input from AE on owner's costs from other power plant decommissioning projects completed. The actual owner's costs provided by AE were used to estimate owner's costs for the benchmark estimates.

The attached tables provide the benchmark cost estimates for the Fayette Power Project and the Sand Hill Energy Center power plants. A list of the assumptions used in the development of the benchmark cost estimates are provided below each table.

For the Fayette Power Project, only Units 1 and 2 and the common areas for Units 1, 2, and 3 as identified in the attached equipment list was included in the benchmark cost estimate. In addition, the percentage of ownership of Austin Energy was applied to the benchmark cost estimate at a rate of 50% for Units 1 and 2 and 36% for the common items for Units 1, 2, and 3 as noted on the attached equipment and building list.

For the Sand Hill Energy Center benchmark cost estimate, all the equipment listed in the attached equipment list was included in the benchmark cost estimate. For this plant, it was assumed Austin Energy has 100% ownership.

Yours sincerely,

Craig Niedermeier, P.E.
Project Manager

cc: Fred Dymek, AECOM
Greg Sampson, VERTEX

Attachment A
Equipment Lists

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Attachment B
Benchmark Cost Estimates

Fayette Power Plant Austin Energy			
Task	**Description**	**Total Project Cost**	
		Low Range Estimate	**High Range Estimate**
1	Contractor Field OH & General Conditions	$ [redacted]	$ [redacted]
2	Mobilization	$ [redacted]	$ [redacted]
3	Environmental Controls	$ [redacted]	$ [redacted]
4	Hazardous Materials Abatement	$ [redacted]	$ [redacted]
5	Plant Equipment & Piping Decommissioning and Cleaning	$ [redacted]	$ [redacted]
6	Demolition	$ [redacted]	$ [redacted]
7	Site Restoration	$ [redacted]	$ [redacted]
8	Recycling and Salvage	$ [redacted]	$ [redacted]
9	Demobilization	$ [redacted]	$ [redacted]
	Contingency (30%)	$ [redacted]	$ [redacted]
	Demolition Subtotal Costs	$ 20,150,000	$ 34,260,000

Other Estimated Project Costs

Task	Low Range Estimate	High Range Estimate
De-oil, De-energize, and Isolate Equipment	$[redacted]	$[redacted]
Engineering/Permitting Costs (15%-25%)	$[redacted]	$[redacted]
Construction Management/Oversight Costs ($250,000 to $400,000 per month)	$[redacted]	$[redacted]
Soil and Groundwater Remediation	$[redacted]	$[redacted]

Total Project Cost Estimate:	**$ 37,320,000**	**$ 68,560,000**
AE 50% Ownership (Units 1 and 2) and 36% (Common Areas):	**$ 15,780,000**	**$ 29,590,000**

Notes/Assumptions:

1. This is a ‘scaled’ estimate based on other actual power plant decommissioning and demolition cost estimates (a 90 MW, 400 MW, 1100 MW coal power plants of similar vintage). Note that there are a number of plant-specific data that would need to be reviewed and factored into this cost estimate to develop a more accurate estimate of the actual/anticipated costs.
2. Estimate assumes no bonding and non-union labor.
3. Estimate assumes a 18 month duration (low range) and 24 month (high range).
4. ACM and other regulated materials costs are based on similar plants.
5. Costs assume 50% AE ownership for Units 1 and 2 and 36% ownership of common buildings equipment. Costs do not include decommissioning of Unit 3 but does include any equipment/buildings shared by all three units (i.e. coal handling equipment). Costs also assume decommissioning as part of entire plant decommissioning.
6. Equipment included in the estimate are provided in the equipment list for this report.
7. Salvage credit not included in 30% contingency.
8. Owner's costs based on actual costs from a AE power plant decommissioning project.
9. Soil and groundwater remediation costs assume [redacted]. Costs assume closure of [redacted], [redacted], and [redacted] as well as address general environmental issues.

Sand Hill Energy Center Austin Energy			
Task	**Description**	**Total Project Cost**	
		Low Range Estimate	**High Range Estimate**
1	Contractor Field OH & General Conditions	$ [redacted]	$ [redacted]
2	Mobilization	$ [redacted]	$ [redacted]
3	Environmental Controls	$ [redacted]	$ [redacted]
4	Hazardous Materials Abatement	$ [redacted]	$ [redacted]
5	Plant Equipment & Piping Decommissioning and Cleaning	$ [redacted]	$ [redacted]
6	Demolition	$ [redacted]	$ [redacted]
7	Site Restoration	$ [redacted]	$ [redacted]
8	Recycling and Salvage	$ [redacted]	$ [redacted]
9	Demobilization	$ [redacted]	$ [redacted]
	Contingency (30%)	$ [redacted]	$ [redacted]
	Demolition Subtotal Costs	$ 5,716,000	$ 10,382,000

Other Estimated Project Costs

Task	Low Range Estimate	High Range Estimate
De-oil, De-energize, and Isolate Equipment	$ [redacted]	$ [redacted]
Engineering/Permitting Costs (20%-30%)	$ [redacted]	$ [redacted]
Construction Management/Oversight Costs ($250,000 to $400,000 per month)	$ [redacted]	$ [redacted]
Soil and Groundwater Remediation	$ [redacted]	$ [redacted]

Total Project Costs	$ 11,856,000	$ 22,082,000

Notes/Assumptions:

1. This is a ‘scaled’ estimate based on our Decker Creek Power Station decommissioning and demolition cost estimate. There are a number of plant-specific data that would need to be reviewed and factored into this cost estimate to develop a more accurate estimate of the actual/anticipated costs.
2. Estimate assumes no [redacted] based on construction date of plant.
3. Estimate assumes no bonding and non-union labor.
4. Estimate assumes a 9 month duration.
5. Equipment included in the estimate are provided in the equipment list for this report.
6. Salvage credit not included in 30% contingency.
7. Owner's costs based on actual costs from a similar AE power plant decommissioning project.

Appendix C
Survey of Public Utility Commission Proceedings Regarding Non-Nuclear Decommissioning Costs

Survey of Public Utility Commission Proceedings Regarding
Non-Nuclear Power Plant Dismantling Costs Database by Plant Type

Plant Descriptions							Project Costs Approved					Project Costs Requested				
Power Plant	Utility	Type Description	Size (MW)	Location	Actual or Estimated	Year Estimated	Total Project	$/kW	Dismantling Costs	Contingency	Salvage	Total Project	$/kW	Dismantling Costs	Contingency	Salvage
Coal-Fired Steam																
Lansing Smith 1 and 2 and Common	Gulf Power	Coal Fired	305	Florida	Estimated	2013	Decision pending					$ 30,383,000	$ 99.62	n/a	n/a	n/a
Scholz 1 and 2	Gulf Power	Coal Fired	80	Florida	Estimated	2013	Decision pending					$ 11,431,000	$ 142.89	n/a	n/a	n/a
Daniel 1 and 2 and Common	Gulf Power, et al	Coal Fired	1000	Mississippi	Estimated	2013	Decision pending					$ 31,543,000	$ 31.54	n/a	n/a	n/a
Scherer 3 and Common	Gulf Power, et al	Coal Fired	818	Georgia	Estimated	2013	Decision pending					$ 63,091,000	$ 77.13	n/a	n/a	n/a
Breed (Dismantled 1994-2006)	Indiana Michigan Power Company	Coal Fired	400	Indiana	Actual	2005	$ 10,766,584	$ 26.92	$ 12,090,704	$ -	$ (1,324,120)	$ 28,663,000	$ 71.66	$ 25,020,000	$ 5,733,000	$ (2,090,000)
Rockport	Indiana Michigan Power Company	Coal Fired	2600	Indiana	Estimated	2011	$ 27,953,280	$ 10.75	Commission approved 40% based on historical estimated to actual			$ 69,883,200	$ 26.88	$ 71,962,800	$ 17,299,300	$ (19,378,900)
Tanners Creek	Indiana Michigan Power Company	Coal Fired	995	Indiana	Estimated	2011	$ 19,101,880	$ 19.20	Commission approved 40% based on historical estimated to actual			$ 47,754,700	$ 47.99	$ 49,388,440	$ 5,175,760	$ (6,809,500)
Reid Gardner 1, 2, and 3	NV Energy	Coal Fired	557	Nevada	Estimated	2014	Decision pending					$ 45,400,000	$ 81.51	$ 48,200,000	$ 7,200,000	$ (10,000,000)
Navajo	NV Energy, et al	Coal Fired	2250	Arizona	Estimated	2008	Not available					$ 93,061,000	$ 41.36	$ 106,777,664	$ 12,138,336	$ (25,855,000)
Arapahoe	Public Service Company of Colorado	Coal Fired	246	Colorado	Estimated	2014	$ 34,781,000	$ 141.39	$ 32,790,000	$ 5,703,000	$ (3,712,000)	$ 34,781,000	$ 141.39	$ 32,790,000	$ 5,703,000	$ (3,712,000)
Cameo	Public Service Company of Colorado	Coal Fired	73	Colorado	Estimated	2011	$ 3,650,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 14,825,838	$ 203.09	$ 19,284,438	$ 297,006	$ (4,755,606)
Cherokee	Public Service Company of Colorado	Coal Fired	694	Colorado	Estimated	2014	$ 34,700,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 48,588,000	$ 70.01	$ 48,036,000	$ 8,354,000	$ (7,802,000)
Comanche	Public Service Company of Colorado	Coal Fired	1488	Colorado	Estimated	2014	$ 74,400,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 66,462,000	$ 44.67	$ 70,963,000	$ 12,341,000	$ (16,842,000)
Craig	Public Service Company of Colorado	Coal Fired	856	Colorado	Estimated	2014	$ 42,800,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 83,908,000	$ 98.02	$ 81,009,000	$ 14,089,000	$ (11,190,000)
Hayden	Public Service Company of Colorado	Coal Fired	446	Colorado	Estimated	2014	$ 22,300,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 47,289,000	$ 106.03	$ 45,234,000	$ 7,867,000	$ (5,812,000)
Pawnee	Public Service Company of Colorado	Coal Fired	505	Colorado	Estimated	2014	$ 25,250,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 71,013,000	$ 140.62	$ 65,443,000	$ 11,381,000	$ (5,811,000)
Valmont	Public Service Company of Colorado	Coal Fired	186	Colorado	Estimated	2014	$ 9,300,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 30,630,000	$ 164.68	$ 30,679,000	$ 28,000	$ (77,000)
Zuni	Public Service Company of Colorado	Coal Fired	107	Colorado	Estimated	2014	$ 5,350,000	$ 50.00	Commission approved using "National Average per kW Cost"			$ 21,876,000	$ 204.45	$ 20,881,000	$ 3,631,000	$ (2,636,000)
Mohave Generating Station	Southern California Edison, et al	Coal Fired	1580	Nevada	Actual/Estimated	2009	$ 57,121,570	$ 36.15	$ 63,071,938	$ 4,728,571	$ (10,678,939)	$ 57,121,570	$ 36.15	$ 63,071,938	$ 4,728,571	$ (10,678,939)
Harrington	Southwestern Public Service Company	Coal Fired	1041	Texas	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 29,755,120	$ 28.58	$ 46,555,305	$ 7,109,370	$ (23,909,555)
Tolk	Southwestern Public Service Company	Coal Fired	1080	Texas	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 35,775,533	$ 33.13	$ 50,409,156	$ 7,502,506	$ (22,136,129)
J. Robert Welsh Units 1-3	SWEPCO	Coal Fired	1584	Texas	Estimated	2012	$ 915,759	$ 0.58	$ 21,124,841	$ 7,294,300	$ (27,503,382)	$ 915,759	$ 0.58	$ 21,124,841	$ 7,294,300	$ (27,503,382)
Dolet Hills Unit 1	SWEPCO, et al	Lignite Fired	640	Louisiana	Estimated	2012	$ 17,740,834	$ 27.72	$ 25,802,381	$ 5,976,000	$ (14,037,547)	$ 17,740,834	$ 27.72	$ 25,802,381	$ 5,976,000	$ (14,037,547)
Flint Creek Unit 1	SWEPCO, et al	Coal Fired	528	Arkansas	Estimated	2012	$ 4,923,094	$ 9.32	$ 11,430,051	$ 3,165,500	$ (9,672,457)	$ 4,923,094	$ 9.32	$ 11,430,051	$ 3,165,500	$ (9,672,457)
Henry W. Pirkey Unit 1	SWEPCO, et al	Lignite Fired	675	Texas	Estimated	2012	$ 12,819,548	$ 18.99	$ 21,613,735	$ 5,366,000	$ (14,160,187)	$ 12,819,548	$ 18.99	$ 21,613,735	$ 5,366,000	$ (14,160,187)
John D. Turk Unit 1	SWEPCO, et al	Coal Fired	600	Arkansas	Estimated	2012	$ 14,324,345	$ 23.87	$ 25,349,988	$ 6,419,200	$ (17,444,843)	$ 14,324,345	$ 23.87	$ 25,349,988	$ 6,419,200	$ (17,444,843)
Big Bend	Tampa Electric	Coal Fired	1700	Florida	Estimated	2011	$ 58,809,000	$ 34.59	$ 70,367,650	$ 8,821,350	$ (20,380,000)	$ 58,809,000	$ 34.59	$ 70,367,650	$ 8,821,350	$ (20,380,000)
Gas-Fired Steam																
Cape Canaveral	Florida Power and Light	Gas Fired	804	Florida	Estimated	2009	$ 16,147,799	$ 20.08	$ 19,991,978	$ 2,583,648	$ (6,427,827)	$ 16,147,799	$ 20.08	$ 19,991,978	$ 2,583,648	$ (6,427,827)
Manatee Plant Units 1-2	Florida Power and Light	Gas Fired	1727	Florida	Estimated	2009	$ 40,445,467	$ 23.42	$ 45,962,803	$ 6,471,275	$ (11,988,611)	$ 40,445,467	$ 23.42	$ 45,962,803	$ 6,471,275	$ (11,988,611)
Martin Plant Units 1-2	Florida Power and Light	Gas/Oil Fired	1727	Florida	Estimated	2009	$ 35,788,752	$ 20.72	$ 42,946,717	$ 5,726,200	$ (12,884,165)	$ 35,788,752	$ 20.72	$ 42,946,717	$ 5,726,200	$ (12,884,165)
Port Everglades	Florida Power and Light	Gas Fired/Gas Turbine	1666	Florida	Estimated	2009	$ 59,168,348	$ 35.52	$ 60,607,065	$ 9,466,936	$ (10,905,653)	$ 59,168,348	$ 35.52	$ 60,607,065	$ 9,466,936	$ (10,905,653)
Cunningham	Southwestern Public Service Company	Gas Fired	485	New Mexico	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 13,051,957	$ 26.91	$ 18,156,965	$ 2,943,713	$ (8,048,721)
Jones	Southwestern Public Service Company	Gas Fired	824	Texas	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 19,832,386	$ 24.07	$ 25,425,215	$ 4,068,928	$ (9,661,757)
Maddox	Southwestern Public Service Company	Gas Fired/Gas Turbine	188	New Mexico	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 9,712,328	$ 51.66	$ 11,409,544	$ 1,844,861	$ (3,542,077)
Moore County	Southwestern Public Service Company	Gas Fired	73	Texas	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 9,129,118	$ 125.06	$ 9,743,359	$ 1,690,341	$ (2,304,582)
Nichols	Southwestern Public Service Company	Gas Fired	457	Texas	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 22,040,027	$ 48.23	$ 26,667,245	$ 4,492,243	$ (9,119,461)
Plant X	Southwestern Public Service Company	Gas Fired	442	Texas	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 21,299,223	$ 48.19	$ 27,646,173	$ 4,670,354	$ (11,017,304)
Knox Lee Units 1-5	SWEPCO	Gas Fired	488	Texas	Estimated	2012	$ 6,347,197	$ 13.01	$ 13,189,052	$ 3,534,900	$ (10,376,755)	$ 6,347,197	$ 13.01	$ 13,189,052	$ 3,534,900	$ (10,376,755)
Lieberman Units 1-4	SWEPCO	Gas Fired	268	Louisiana	Estimated	2012	$ 881,508	$ 3.29	$ 5,043,128	$ 1,624,400	$ (5,786,020)	$ 881,508	$ 3.29	$ 5,043,128	$ 1,624,400	$ (5,786,020)
Lone Star Unit 1	SWEPCO	Gas Fired	50	Texas	Estimated	2012	$ 1,084,049	$ 21.68	$ 1,921,421	$ 486,800	$ (1,324,172)	$ 1,084,049	$ 21.68	$ 1,921,421	$ 486,800	$ (1,324,172)
Wilkes Units 1-3	SWEPCO	Gas Fired	901	Texas	Estimated	2012	$ 1,330,374	$ 1.48	$ 933,900	$ 3,389,700	$ (2,993,226)	$ 1,330,374	$ 1.48	$ 933,900	$ 3,389,700	$ (2,993,226)
Gas Turbine																
Cutler	Florida Power and Light	Gas Turbine	237	Florida	Estimated	2009	$ 10,095,581	$ 42.60	$ 11,310,568	$ 1,615,293	$ (2,830,280)	$ 10,095,581	$ 42.60	$ 11,310,568	$ 1,615,293	$ (2,830,280)
Blue Spruce	Public Service Company of Colorado	Gas Turbine	310	Colorado	Estimated	2014	$ 12,400,000	$ 40.00	Commission approved using "National Average per kW Cost"			$ 4,842,000	$ 15.62	$ 5,116,000	$ 890,000	$ (1,164,000)
Carlsbad	Southwestern Public Service Company	Gas Turbine	11	New Mexico	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 495,039	$ 45.00	$ 495,617	$ 74,343	$ (74,921)
Maddox 2	Southwestern Public Service Company	Combustion Gas Turbine	60	New Mexico	Estimated	2014	Decision pending, study used in cases for both Texas and New Mexico					$ 9,712,328	$ 161.87	$ 11,409,544	$ 1,844,861	$ (3,542,077)
Riverview	Southwestern Public Service Company	Combustion Gas Turbine	23	Texas	Estimated	2012	Decision pending, study used in cases for both Texas and New Mexico					$ 2,964,659	$ 128.90	$ 3,151,102	$ 467,728	$ (654,171)
Harry D. Mattison Units 1-4	SWEPCO	Combustion Gas Turbine	304	Arkansas	Estimated	2012	$ 3,350,299	$ 11.02	$ 3,693,551	$ 712,300	$ (1,055,552)	$ 3,350,299	$ 11.02	$ 3,693,551	$ 712,300	$ (1,055,552)
J. Lamar Stall	SWEPCO	Combustion Gas Turbine	507	Louisiana	Estimated	2012	$ 124,864	$ 0.25	$ 4,275,570	$ 1,486,900	$ (5,637,606)	$ 124,864	$ 0.25	$ 4,275,570	$ 1,486,900	$ (5,637,606)
Bayside	Tampa Electric	Combustion Gas Turbine	1800	Florida	Estimated	2011	$ 7,506,000	$ 4.17	$ 20,586,100	$ 1,125,900	$ (14,206,000)	$ 7,506,000	$ 4.17	$ 20,586,100	$ 1,125,900	$ (14,206,000)
Combined Cycle																
Fort Lauderdale	Florida Power and Light	Combined Cycle	1042	Florida	Estimated	2009	$ 24,721,603	$ 23.73	$ 27,501,811	$ 3,955,456	$ (6,735,664)	$ 24,721,603	$ 23.73	$ 27,501,811	$ 3,955,456	$ (6,735,664)
Fort Myers	Florida Power and Light	Combined Cycle/Gas Turbine	2566	Florida	Estimated	2009	$ 28,682,321	$ 11.18	$ 34,610,305	$ 4,589,171	$ (10,517,155)	$ 28,682,321	$ 11.18	$ 34,610,305	$ 4,589,171	$ (10,517,155)
Manatee Plant Unit 3	Florida Power and Light	Combined Cycle	1150	Florida	Estimated	2009	$ 22,780,807	$ 19.81	$ 23,356,666	$ 3,644,929	$ (4,220,788)	$ 22,780,807	$ 19.81	$ 23,356,666	$ 3,644,929	$ (4,220,788)
Martin Plant Units 3-4, 8	Florida Power and Light	Combined Cycle	1978	Florida	Estimated	2009	$ 31,975,578	$ 16.17	$ 38,307,560	$ 5,116,092	$ (11,448,074)	$ 31,975,578	$ 16.17	$ 38,307,560	$ 5,116,092	$ (11,448,074)
Pea Ridge Cogen	Gulf Power, et al	Combined Cycle	15	Florida	Estimated	2013	$ 150,000	$ 10.00	$ 151,000	$ 14,000	$ (15,000)	$ 151,000	$ 10.07	$ 151,000	$ 14,000	$ (15,000)
Chuck Lenzie	NV Energy	Combined Cycle	1170	Nevada	Estimated	2010	$ 11,919,025	$ 10.19	$ 13,074,731	$ 2,511,254	$ (3,666,960)	$ 23,574,178	$ 20.15	$ 18,160,759	$ 9,080,380	$ (3,666,960)
Harry Allen	NV Energy	Combined Cycle	631	Nevada	Estimated	2010	$ 9,659,172	$ 15.31	$ 9,874,998	$ 1,780,734	$ (1,996,560)	$ 17,731,635	$ 28.10	$ 13,152,130	$ 6,576,065	$ (1,996,560)
Silverhawk	NV Energy	Combined Cycle	560	Nevada	Estimated	2010	$ 4,437,947	$ 7.92	$ 5,214,176	$ 1,057,130	$ (1,833,360)	$ 8,068,673	$ 14.41	$ 6,601,355	$ 3,300,679	$ (1,833,360)
Sunrise	NV Energy	Combined Cycle	152	Nevada	Estimated	2010	$ 4,383,472	$ 28.84	$ 4,455,690	$ 799,042	$ (871,260)	$ 8,464,451	$ 55.69	$ 6,223,807	$ 3,111,904	$ (871,260)
Walter M. Higgins	NV Energy	Combined Cycle	550	Nevada	Estimated	2010	$ 9,479,443	$ 17.24	$ 9,598,086	$ 1,714,717	$ (1,833,360)	$ 18,819,883	$ 34.22	$ 13,768,829	$ 6,884,415	$ (1,833,360)
Ft. St. Vrain	Public Service Company of Colorado	Natural Gas Combined Cycle	965	Colorado	Estimated	2014	$ 38,600,000	$ 40.00	Commission approved using "National Average per kW Cost"			$ 24,501,000	$ 25.39	$ 25,593,000	$ 4,451,000	$ (5,543,000)
Rocky Mountain	Public Service Company of Colorado	Natural Gas Combined Cycle	600	Colorado	Estimated	2014	$ 24,000,000	$ 40.00	Commission approved using "National Average per kW Cost"			$ 14,804,000	$ 24.67	$ 14,531,000	$ 2,527,000	$ (2,254,000)
Arsenal Hill	SWEPCO	Combined Cycle Natural Gas	110	Louisiana	Estimated	2012	$ 3,081,751	$ 28.02	$ 4,365,075	$ 996,800	$ (2,280,124)	$ 3,081,751	$ 28.02	$ 4,365,075	$ 996,800	$ (2,280,124)
Polk	Tampa Electric	Combined Cycle	940	Florida	Estimated	2011	$ 37,600	$ 0.04	$ 11,567,960	$ 5,640	$ (11,536,000)	$ 37,600	$ 0.04	$ 11,567,960	$ 5,640	$ (11,536,000)
Cherokee Units 5 - 7, CCX2 and Common	Public Service Company of Colorado	Natural Gas Combined Cycle	569	Colorado	Estimated	2014	$ 38,600,000	$ 40.00	Commission approved using "National Average per kW Cost"			$ 8,465,000	$ 14.88	$ 9,032,000	$ 1,571,000	$ (2,138,000)

Survey of Public Utility Commission Proceedings Regarding
Non-Nuclear Power Plant Dismantling Costs Database by Plant Type

Notes/Sources

Power Plant	Utility	Project Estimate Source	Final Amount Source
Coal-Fired Steam			
Lansing Smith 1 and 2 and Common	Gulf Power	Gulf Power 2009 Study (FPSC Docket 090319-EI), escalated to 2013 (Docket 130151-EI, consolidated with Docket 130140-EI)	
Scholz 1 and 2	Gulf Power	Gulf Power 2009 Study (FPSC Docket 090319-EI), escalated to 2013 (Docket 130151-EI, consolidated with Docket 130140-EI)	
Daniel 1 and 2 and Common	Gulf Power, et al	Gulf Power 2009 Study (FPSC Docket 090319-EI), escalated to 2013 (Docket 130151-EI, consolidated with Docket 130140-EI)	
Scherer 3 and Common	Gulf Power, et al	Gulf Power 2009 Study (FPSC Docket 090319-EI), escalated to 2013 (Docket 130151-EI, consolidated with Docket 130140-EI)	
Breed (Dismantled 1994-2006)	Indiana Michigan Power Company	Sargent & Lundy Study for IN Docket 42959	Staff Testimony Accepted by Commission pg. 10
Rockport	Indiana Michigan Power Company	Sargent & Lundy Study for IN Docket 44075	Staff Testimony Accepted by Commission pg. 10
Tanners Creek	Indiana Michigan Power Company	Sargent & Lundy Study for IN Docket 44075	Staff Testimony Accepted by Commission pg. 10
Reid Gardner 1, 2, and 3	NV Energy	URS Study for NV Energy, Docket 14-05003	
Navajo	NV Energy, et al	Sargent & Lundy Study prepared for SRP, filed as information in NV Docket 11-06007	
Arapahoe	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement approved Arapahoe decomm	
Cameo	Public Service Company of Colorado	TLG Study for CO Docket 11AL-947E	
Cherokee	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Comanche	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Craig	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Hayden	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Pawnee	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Valmont	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Zuni	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Mohave Generating Station	Southern California Edison, et al	2012 SCE Rate Case	2012 Rate Case Final Order
Harrington	Southwestern Public Service Company	TLG Study for TX Docket 43695	
Tolk	Southwestern Public Service Company	TLG Study for TX Docket 43695	
J. Robert Welsh Units 1-3	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Dolet Hills Unit 1	SWEPCO, et al	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Flint Creek Unit 1	SWEPCO, et al	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Henry W. Pirkey Unit 1	SWEPCO, et al	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
John D. Turk Unit 1	SWEPCO, et al	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Big Bend	Tampa Electric	Burns and McDonald Study for FL Docket 110131-E1	Final Order pg. 12
Gas-Fired Steam			
Cape Canaveral	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Manatee Plant Units 1-2	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Martin Plant Units 1-2	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Port Everglades	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Cunningham	Southwestern Public Service Company	TLG Study for TX Docket 43695, NM Case 14-00332-UT	
Jones	Southwestern Public Service Company	TLG Study for TX Docket 43695, NM Case 14-00332-UT	
Maddox	Southwestern Public Service Company	TLG Study for TX Docket 43695, NM Case 14-00332-UT	
Moore County	Southwestern Public Service Company	TLG Study for TX Docket 43695, NM Case 14-00332-UT	
Nichols	Southwestern Public Service Company	TLG Study for TX Docket 43695, NM Case 14-00332-UT	
Plant X	Southwestern Public Service Company	TLG Study for TX Docket 43695, NM Case 14-00332-UT	
Knox Lee Units 1-5	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Lieberman Units 1-4	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Lone Star Unit 1	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Wilkes Units 1-3	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Gas Turbine			
Cutler	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Blue Spruce	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Carlsbad	Southwestern Public Service Company	TLG Study for TX Docket 43695	
Maddox 2	Southwestern Public Service Company	TLG Study for TX Docket 43695	
Riverview	Southwestern Public Service Company	TLG Study for TX Docket 40824	
Harry D. Mattison Units 1-4	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
J. Lamar Stall	SWEPCO	Sargent & Lundy Study for TX Docket 40443	Order dated 10/10/2013
Bayside	Tampa Electric	Burns and McDonald Study for FL Docket 110131-E1	Final Order pg. 12
Combined Cycle			
Fort Lauderdale	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Fort Myers	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Manatee Plant Unit 3	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Martin Plant Units 3-4, 8	Florida Power and Light	Florida Docket 080677-EI Exhibit KO-8	Docket Final Order
Pea Ridge Cogen	Gulf Power, et al	Gulf Power 2009 Study (FPSC Docket 090319-EI), escalated to 2013 (Docket 130151-EI, consolidated with Docket 130140-EI)	
Chuck Lenzie	NV Energy	URS Study for NV Docket 11-06007	Final Order pg. 35
Harry Allen	NV Energy	URS Study for NV Docket 11-06007	Final Order pg. 35
Silverhawk	NV Energy	URS Study for NV Docket 11-06007	Final Order pg. 35
Sunrise	NV Energy	URS Study for NV Docket 11-06007	Final Order pg. 35
Walter M. Higgins	NV Energy	URS Study for NV Docket 11-06007	Final Order pg. 35
Ft. St. Vrain	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Rocky Mountain	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	
Arsenal Hill	SWEPCO	Sargent & Lundy Study for TX Docket 40443	
Polk	Tampa Electric	Burns and McDonald Study for FL Docket 110131-E1	Final Order pg. 12
Cherokee Units 5 - 7, CCX2 and Common	Public Service Company of Colorado	Burns and McDonnell Study for CO Docket 14AL-0660E, settlement agreement - forego any change in decommissioning, except Arapahoe	

February 17, 2011

R·W·BECK
An SAIC Company

Mrs. Ann Little
VP, Finance and Corporate Services
Austin Energy
721 Barton Springs Road
Austin, TX 78704

Subject: **Transmission & Distribution Loss Study**

Dear Mrs. Little:

R. W. Beck has completed the Transmission and Distribution Loss Study for Austin Energy to quantify the transmission and distribution facility losses for the preparation of a rate study. The purpose of this report is to summarize the basis of the loss calculations, methodologies used, and findings.

The electric system, for the purposes of this study, is defined as the transmission and distribution system equipment required to distribute electrical power to each Austin Energy customer. Information about the Austin Energy power system configuration, equipment types and ratings, primary and secondary circuit types and lengths, historical data, and transformer loads was provided by Austin Energy. The Austin Energy power system evaluated can be characterized by the following statistics and principal types of equipment as of fiscal year 2009:

Type	Quantity	Location of Loss Calculations
System Peak Demand	2,602 MW (1)	
Annual Energy Purchases	12,659,087 MWh (2)	
Annual Energy Sales	12,076,915 MWh (2)	
Annual Losses	4.60 %	Exhibit A
Circuit-miles of Transmission		Exhibit B
345 kV	268.9 mi.	
138 kV	322.9 mi.	
69 kV	26.1 mi.	
Transmission Transformers	17	Exhibit C
Substation Transformers	151	Exhibit D
Circuit-miles of Distribution Operating at 12.5 kV	4,810 mi.	Exhibit E
Distribution Transformers	86,179	Exhibit F
Number of Customers	414,174	
Circuit-miles of Secondary Operating at 1.0 kV & below	6,034 mi.	Exhibit H
Street & Security Lights	63,495	Exhibit I

Notes:
(1) Reading for June 2009
(2) Provided by Austin Energy based on the Proof of Revenue

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Analysis Summary

The calculated transmission and distribution system losses for fiscal year 2009 are summarize in the table below. Additional details of the loss calculations are included in Exhibits A through J. Charts illustrating the calculated losses by voltage level are given in Figure 1 and Figure 2.

Type	Annual Energy Losses (MWh)	Demand Losses at Peak (MW)
Transmission 345 kV	15,439	5.37
Transmission 138 kV	181,956	60.22
Transmission 69 kV	5,078	1.36
Distribution	155,897	48.87
Secondary	208.178	38.44
Non-Technical	15,625	0
TOTALS	582,172	154.26

Note: Lights were assumed to be off during the 2009 system peak.

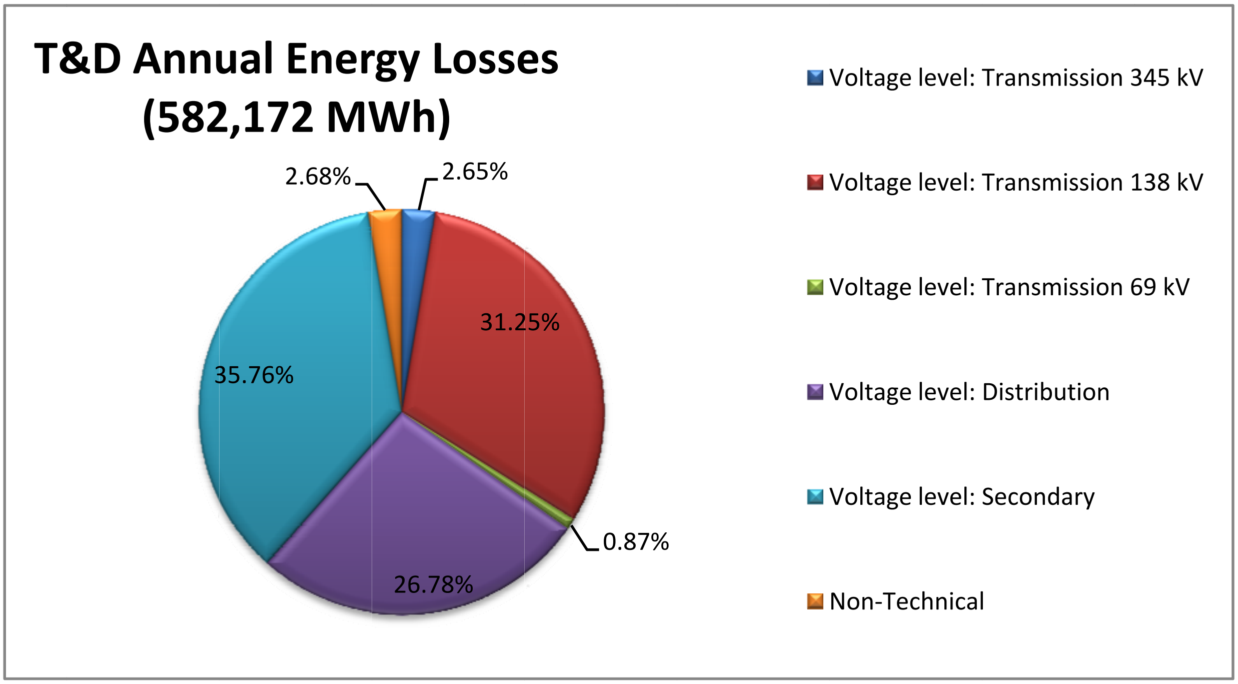

Figure 1. Calculated Annual Energy Losses by Voltage Level

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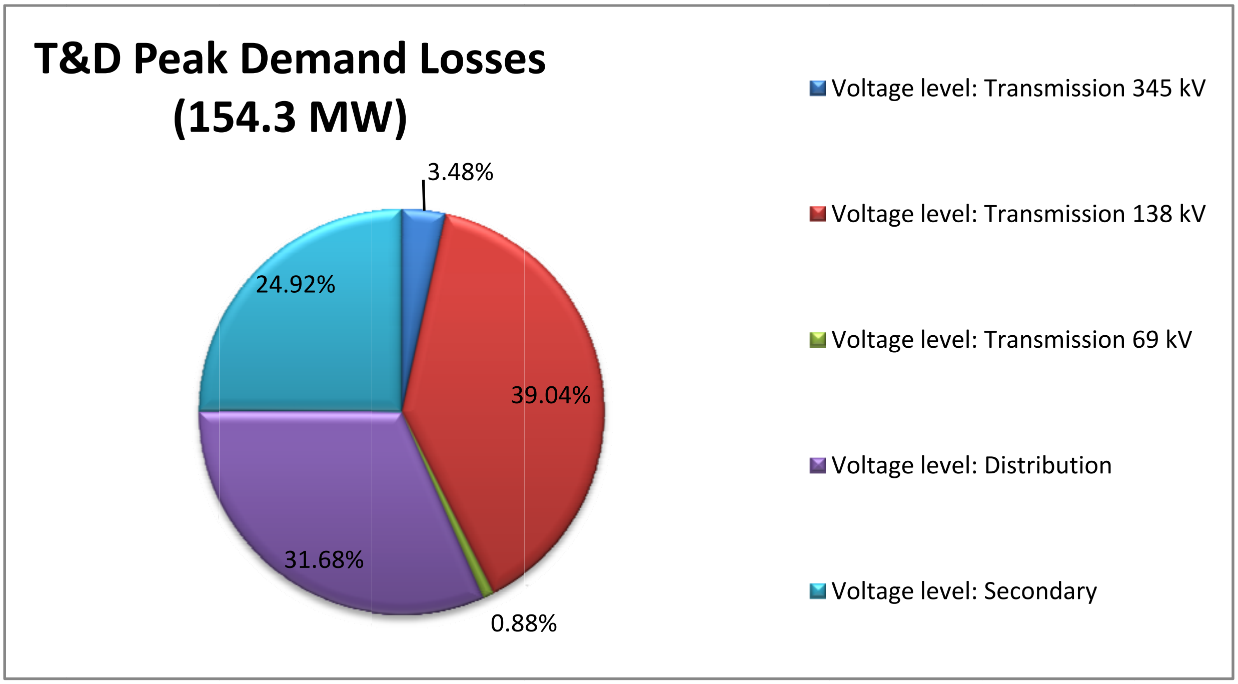

Figure 2. Calculated Annual Energy Losses by Voltage Level

Basis of Analysis

System losses can be categorized as technical and non-technical losses. Non-technical losses can be attributed to unmetered loads (such as station service), loose hardware, corona or other mechanical abnormalities, metering inaccuracies, theft, etc. For the purposes of this study, the non-technical losses were estimated based on the total system losses, which are calculated from the annual energy sales and purchases, less the calculated technical losses.

Technical system losses are an unavoidable result of delivering power to electric utility customers, due to the physics of power flow and voltage transformation. In addition, technical losses can be broken into two groups: 1) constant losses, which are independent of the system loading; and 2) variable losses, which are dependent on system loading.

Constant losses consist primarily of transformer core losses, or no-load losses. The constant system losses included in this study were based on the name plate losses and the assumed time period of one year.

Variable losses include transmission and distribution line losses for the primary and secondary systems, and transformer winding, or load losses. The variable losses included in this study were based on the calculated losses at peak, the assumed time period of one year, and the Loss Factor.

Mrs. Ann Little
February 17, 2011
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The equation for the Loss Factor is as follows:

$$Loss\ Factor = k * Load\ Factor + (1 - k) * Load\ Factor^2$$

A value of 0.08 was assumed for the constant coefficient "k" for the Loss Factor calculations based on research[1] published in IEEE Transactions on Power Systems on November 1988 using American and Canadian utilities. The average annual Load Factor for the fiscal year 2009 of 55.54% was calculated based on the Austin Energy monthly system peak and energy purchases.

Information about the Austin Energy power system configuration, equipment types and ratings, primary circuit types and lengths, historical data, and transformer loads was provided by Austin Energy.

Transmission & Distribution System

Losses for the transmission and distribution systems were taken from the load flow results provided by Austin Energy from the existing engineering models. The load flow results were based on the 2009 system peak, recorded in August. The transmission system is modeled in PTI Interactive Power System Simulator (PSSE™), and submitted to ERCOT as required. The distribution system is modeled in FeederALL®, which is used internally for system planning and operations.

The load flow results at the 2009 system peak provided data for transmission and distribution line losses, and substation transformer load losses. Substation transformer no-load losses were obtained from Austin Energy manufacturer test report summaries. If test reports were not available for a given transformer, impedances and no-load loss values were assumed based on similar sized transformers. The transmission and distribution line losses are presented in Exhibit B and Exhibit E, respectively. Transmission substation transformer load and no-load losses are presented in Exhibit C, while the distribution substation transformer losses are presented in Exhibit D.

Distribution Transformers

Inventory of the installed distribution transformer capacities and configurations was provided by Austin Energy from the existing GIS system. Distribution transformer specifications were based on a number of manufacturer test reports provided by Austin Energy. If test reports were not available for a given transformer, impedances and no-load loss values were assumed based on similar sized transformers. A summary of the distribution transformer specifications used in the loss calculations is given in Exhibit G.

Loading for the distribution transformers was estimated using the total installed distribution transformer capacity and the estimated customer demand at the 2009 peak. Distribution transformer no-load and load losses are listed in Exhibit F.

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[1] M.W. Gustafson and J.S. Baylor, "The Equivalent Hours Loss Factor Revisited", IEEE Trans. On Power Systems, Vol. 3, No. 4. pp 1502-1508, November 1988.

Secondary System

Austin Energy's existing GIS system also provided information related to the installed secondary conductor types and lengths for each of the following categories: service, secondary, and street lights. Losses in the secondary system were estimated based on the service category, average lengths, conductor types, and the estimated conductor loading.

For service lines, the conductor loading was estimated based on the total service conductor capacity and the estimated customer demand at the 2009 peak. Secondary lines were assumed to be sized similar to service lines by Austin Energy. Based on this assumption, the conductor loading for both secondary and services were assumed to be equal. Conductor loading for the secondary serving security and street lights was calculated based on the estimated lighting load, as provided by Austin Energy, and the total conductor capacity. Secondary line losses are presented in Exhibit H.

Security & Street Lights

Consumption estimates for security and street lights were provided by Austin Energy, which accounted for the light, the ballast, and other miscellaneous losses associated with each lamp size. The quantity of lights by size and type were also provided by Austin Energy based on information included in the existing GIS system. However, the total number of lights in the GIS system was greater than the number of lights billed for fiscal year 2009. As a result, the losses for security and street light losses were calculated based on the difference in the estimated annual energy consumption derived from the GIS data less the total lighting sales for fiscal year 2009. Security and street light losses are presented in Exhibit I.

We wish to acknowledge the cooperation and assistance from the management and staff of Austin Energy in the preparation of this study. If you have any questions or need further assistance, please call. We look forward to working with you again.

Sincerely,

R. W. BECK, INC.

Keith Mullen, P.E.
Project Manager

PKM/mw

AUSTIN ENERGY

Evaluation of T&D System Losses

Summary of T&D System Losses

SYSTEM LOSSES

	Austin Energy
2009 Annual Net Available for Sale (MWh)	12,659,087
2009 Annual Energy Sales (MWh)	12,076,915
ANNUAL SYSTEM LOSSES (MWh)	**582,172**
PERCENT SYSTEM LOSSES	**4.60%**

TYPE	ANNUAL ENERGY LOSSES (MWh)[(2)]	PERCENT OF AE ENERGY AVAILABLE	PERCENT OF TOTAL AE LOSSES	DEMAND LOSSES AT PEAK (MW)	PERCENT OF DEMAND AE LOSSES AT PEAK
Voltage Level: Transmission 345 kV	15,439	**0.12%**	2.65%	5.37	3.48%
Transmission Line Losses	15,439	**0.12%**	2.65%	5.37	3.48%
Transmission Substation Transformer Losses					
Core	0	**0.00%**	0.00%	0.00	0.00%
Winding	0	**0.00%**	0.00%	0.00	0.00%
Voltage Level: Transmission 138 kV	181,956	**1.44%**	31.25%	60.22	39.04%
Transmission Line Losses	153,844	**1.22%**	26.43%	53.51	34.69%
Transmission Substation Transformer Losses					
Core	13,133	**0.10%**	2.26%	1.50	0.97%
Winding	14,979	**0.12%**	2.57%	5.21	3.38%
Voltage Level: Transmission 69 kV	5,078	**0.04%**	0.87%	1.36	0.88%
Transmission Line Losses	2,875	**0.02%**	0.49%	1.00	0.65%
Transmission Substation Transformer Losses					
Core	1,743	**0.01%**	0.30%	0.20	0.13%
Winding	460	**0.00%**	0.08%	0.16	0.10%
Voltage Level: Distribution	155,897	**1.23%**	26.78%	48.87	31.68%
Distribution Line Losses	104,037	**0.82%**	17.87%	36.19	23.46%
Distribution Substation Transformer Losses					
Core	22,893	**0.18%**	3.93%	2.61	1.69%
Winding	28,967	**0.23%**	4.98%	10.08	6.53%
Voltage Level: Secondary	208,178	**1.64%**	35.76%	38.44	24.92%
Distribution Transformer Losses					
Core	139,886	**1.11%**	24.03%	15.97	10.35%
Winding	21,803	**0.17%**	3.75%	7.58	4.92%
Service and Secondary Line Losses	42,789	**0.34%**	7.35%	14.89	9.65%
Street & Security Lights[(1)(3)]	3,700	**0.03%**	0.64%	0.00	0.00%
Loose Hardware, Corona or Other Mechanical Abnormalities and Metering Inaccuracies	15,625	**0.12%**	2.68%	0.00	0.00%
TOTALS	582,172	**4.60%**	100.00%	154.26	100.00%

Notes:
(1) Street and Security Light losses are the difference in billed kWh and total kWh for all lights
(2) Annual Energy Losses were determined using the following equations:
Annual Energy Losses = Peak Demand (kW) * Time (hrs) * Loss Factor
Loss Factor = k * Load Factor + (1 - k) * (Load Factor)^2
"k" constant 0.08
Load Factor 55.54%
(3) Street and Security Light were off at the recorded peak
(4) GSU's results are categorized by the high side voltage, all other transformer results are categorized by low side voltage

Exhibit B
Transmission Line Losses

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Transmission Line Losses

TRANSMISSION VOLTAGE (kV)	MILES OF LINE (1)	DEMAND LOSSES AT 2009 PEAK (kW)(2)	ANNUAL ENERGY LOSSES (kWh)
69	26.1	1,000	2,875,055
138	322.9	53,510	153,844,203
345	268.9	5,370	15,439,046
TOTALS	617.9	59,880	172,158,304

Notes:
(1) Transmission line length were provided by AE

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Transmission Substation Transformer Losses

SUBSTATION NAME	TRANSFORMER VOLTAGE	TRANSFORMER BASE RATING (MVA)	TRANSFORMER NO-LOAD LOSSES (kW) (1)	ANNUAL (2) NO-LOAD ENERGY LOSSES (kWh)	TRANSFORMER LOAD LOSSES (kW) (3)	ANNUAL (4) LOAD ENERGY LOSSES (kWh)
NL AT1	138/69 kV	220	35.6	311,462	30	86,252
KB AT1	138/69 kV	220	51.8	453,768	70	201,254
SP-AT1	138/69 kV	220	61.6	539,861	30	86,252
PE-AT1	138/69 kV	220	50.0	437,912	30	86,252
GF AT1	345/138 kV	480	90.0	788,400	260	747,514
GF AT2	345/138 kV	480	91.7	803,292	30	86,252
LY AT1	345/138 kV	480	124.9	1,093,861	500	1,437,528
LY AT2	345/138 kV	480	98.1	859,356	260	747,514
AU AT1	345/138 kV	480	118.0	1,033,855	700	2,012,539
AU AT2	345/138 kV	480	121.2	1,061,975	590	1,696,283
DP MT1	22.8/138 kV	420	219.5	1,922,470	720	2,070,040
DP MT2	22.8/138 kV	470	232.6	2,037,313	970	2,788,804
DP MPT1(5)	13.8/138 kV	139	51.0	446,760	90	258,755
DP MPT2(5)	13.8/138 kV	139	51.0	446,760	70	201,254
SA MPT1(6)	13.8/138 kV	130	52.0	455,520	130	373,757
SA MPT2(7)	13.8/138 kV	130	50.0	438,000	210	603,762
SA AT1(8)	18.0/138 kV	480	199.2	1,744,992	680	1,955,038
345 kV TOTALS		0	0.0	0	0	0
138 kV TOTALS(9)		4,788	1,499.2	13,132,554	5,210	14,979,037
69 kV TOTALS(9)		880	199.0	1,743,003	160	460,009
TOTALS		5,668	1,698.1	14,875,557	5,370	15,439,046

Notes:
(1) From test reports provided by Austin Energy
(2) Annual No-Load Energy Losses is based on calculated demand losses times 8760 hours.
(3) Calculated in Feederall model with 2009 peak load flows
(4) Annual Load Energy Losses is based on transformer load losses, 8760 hours, and a loss factor calculated from the annual load factor
(5) No-Load Demand Losses are estimated to be the same as Sandhill Transformers of similar size
(6) Losses for SANDH_G1 and SANDH_G2
(7) Losses for SANDH_G3 and SANDH_G4
(8) Losses for SANDHG5A and SANDHG5C
(9) GSU's results are categorized by the high side voltage, all other transformer results are categorized by low side voltage

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Distribution Substation Transformer Losses

SUBSTATION NAME	TRANSFORMER BASE RATING (MVA)	2009 COINCIDENT PEAK LOAD (kW)	TRANSFORMER NO-LOAD LOSSES (kW) (1)(7)	ANNUAL (2) NO-LOAD ENERGY LOSSES (kWh)	TRANSFORMER LOAD LOSSES (kW) (3)	ANNUAL (4) LOAD ENERGY LOSSES (kWh)
AD123	30	10,590	16.0	140,160	22.0	63,194
AD456	30	14,196	16.0	140,072	42.8	123,081
AG123	30	14,491	14.1	123,831	24.7	70,870
AG456	30	21,682	14.0	122,500	103.9	298,833
BAL TX1(5)(6)	25	5,391	16.4	143,752	13.4	38,497
BAL TX2(5)(6)	25	5,372	16.4	143,752	13.4	38,497
BA012	30	22,492	13.1	114,590	110.7	318,211
BA123	30	18,140	9.4	82,344	82.6	237,422
BA456	30	17,619	36.1	316,236	80.8	232,218
BA789	30	16,235	15.4	134,816	52.7	151,630
BC123	30	11,862	26.3	230,476	48.7	139,929
BC456	30	17,987	18.9	165,914	58.2	167,242
BC789	30	14,022	13.9	121,764	39.7	114,168
BE123	30	17,302	13.8	120,958	53.6	154,103
BE456	30	0	0.0	0	0.0	0
BL123	30	26,681	13.9	121,764	144.0	414,008
BL456	30	17,048	16.3	142,788	50.1	143,897
BL789	30	19,901	14.8	129,560	87.3	251,107
BR123	70	18,858	49.6	434,496	32.9	94,618
BR456	70	19,037	50.7	444,307	87.1	250,532
BR789	70	19,278	26.5	232,140	27.2	78,288
BU123	30	15,728	14.8	129,560	53.3	153,269
BU456	30	19,341	14.8	129,560	81.7	234,777
BU789	30	27,354	29.0	254,040	136.6	392,848
CC123	30	11,903	14.4	126,144	27.4	78,719
CC456	30	12,290	10.1	88,301	25.0	71,819
CA123	30	21,634	14.2	123,954	87.0	250,015
CA456	30	23,180	14.1	123,078	112.0	321,862
CF123	30	17,606	15.6	136,919	68.2	196,165
CF456	30	19,434	12.0	105,120	75.6	217,325
CF789	30	18,566	13.1	114,590	72.9	209,534
CL012	30	15,602	13.6	119,311	28.9	83,175
CL123	30	22,422	14.3	124,909	64.4	185,096
CL456	30	8,246	13.9	121,764	13.4	38,497
CL789	30	17,842	13.5	118,523	39.2	112,731
CM123	30	16,897	9.2	80,942	70.5	202,634
CM456	30	21,937	8.4	73,496	131.6	378,329
CM789	30	19,510	13.2	116,061	82.5	237,221
DE123	30	21,908	13.6	119,048	161.3	463,861
DE456	50	8,995	18.5	162,060	9.1	26,106
DE789	50	16,346	18.6	162,848	27.5	79,150
DE101112	50	16,688	19.7	172,484	25.2	72,336
DE131415	50	14,413	19.0	166,002	23.8	68,311
DE161718	50	5,135	25.6	223,818	2.0	5,779
DE192021	50	6,888	25.9	226,534	2.8	8,108
DG123	30	15,425	32.7	286,802	59.0	169,715
DG456	30	6,389	13.4	117,743	8.1	23,173
EB012	50	4,598	20.7	181,157	5.4	15,468
EB123	50	24,214	23.0	201,830	124.7	358,634
EB456	50	4,987	22.0	192,720	6.3	18,199
EB789	50	0	22.0	192,720	0.0	0
FI123	30	18,312	13.9	121,764	64.7	186,016
FI456	30	13,960	13.9	121,764	36.8	105,773
FV123	30	18,155	14.2	124,042	59.4	170,865
FV456	30	21,696	18.0	157,417	88.2	253,494
GR12	30	5,405	11.8	103,018	6.2	17,768
GR45	30	7,748	12.5	109,325	12.9	37,146
GR789	30	22,482	36.1	316,236	131.5	377,926
HC012	30	24,361	13.9	121,764	123.4	354,724

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Distribution Substation Transformer Losses

SUBSTATION NAME	TRANSFORMER BASE RATING (MVA)	2009 COINCIDENT PEAK LOAD (kW)	TRANSFORMER NO-LOAD LOSSES (kW) (1)(7)	ANNUAL (2) NO-LOAD ENERGY LOSSES (kWh)	TRANSFORMER LOAD LOSSES (kW) (3)	ANNUAL (4) LOAD ENERGY LOSSES (kWh)
HC123	30	24,917	32.5	284,350	147.1	423,036
HC456	30	19,349	28.8	252,288	72.7	209,103
HC789	30	18,988	11.5	100,740	82.6	237,537
HL123	30	15,738	16.1	140,861	43.3	124,490
HL456	30	18,717	14.2	124,392	84.9	244,063
HM012	30	16,732	13.7	120,100	33.9	97,558
HM123	30	19,087	28.9	253,339	97.8	281,295
HM456	30	24,221	25.5	223,643	180.3	518,372
HM789	30	16,485	13.3	116,420	67.0	192,485
HV123	30	20,443	13.1	114,633	90.8	260,911
HV456	30	20,707	30.5	267,005	183.0	526,049
JE123	30	21,504	28.7	251,412	112.6	323,587
JE456	30	15,420	13.6	119,136	44.7	128,400
JV123	30	22,620	16.6	145,591	101.8	292,623
JV456	30	13,263	9.4	82,256	36.7	105,371
JV789	30	14,537	13.4	117,621	43.7	125,755
JL123	30	14,493	16.9	147,983	28.0	80,502
JL456	30	16,810	17.0	149,060	40.1	115,175
KB123	30	20,494	28.1	246,156	97.2	279,484
KB456	30	18,731	28.5	249,222	78.2	224,686
KL012	20	0	0.0	0	0.0	0
KL123	20	0	0.0	0	0.0	0
KL345	30	0	0.0	0	0.0	0
KL456	20	0	0.0	0	0.0	0
KL789	20	0	0.0	0	0.0	0
LS123	30	21,272	14.1	123,516	110.0	316,112
LS456	30	17,571	15.0	131,400	66.7	191,824
LW123	30	18,917	15.3	133,678	79.8	229,458
LW456	30	11,342	9.4	82,432	31.7	91,110
MC012	30	9,595	14.8	129,569	20.0	57,587
MC123	30	21,296	32.0	280,495	111.1	319,534
MC456	30	22,473	28.8	251,850	120.0	344,892
MC789	30	19,303	15.6	136,919	94.7	272,181
MP123	30	25,559	15.0	131,400	144.9	416,567
MP456	30	18,914	13.0	113,880	77.8	223,622
MP789	30	19,794	11.5	100,390	64.5	185,355
MT012	30	6,226	12.6	110,551	7.3	20,988
NL012	30	17,327	11.3	98,988	53.1	152,579
NL123	20	15,861	13.0	113,880	109.8	315,710
NL345	30	20,051	7.9	68,941	105.6	303,491
NL789	20	7,528	16.3	142,438	24.5	70,525
NW123	30	13,913	14.1	123,936	43.7	125,755
OC123	30	8,221	14.8	129,569	14.2	40,912
OC456	30	13,972	11.6	101,266	34.5	99,103
OH123	30	14,580	12.1	105,996	47.7	137,226
OH456	30	18,897	11.8	103,368	83.0	238,658
OH789	30	25,826	13.4	117,743	150.9	433,961
PE1234	30	20,504	13.9	121,764	91.0	261,544
PE5678	30	22,726	13.9	121,764	100.9	290,064
PL123	30	22,700	14.1	123,253	108.9	313,094
PL456	0	0	0.0	0	0.0	0
PL789	50	0	0.0	0	0.0	0
PL101112	30	5,351	11.3	99,163	5.3	15,209
PL131415	30	3,749	14.1	123,446	1.7	4,830
RP123	20	358	14.8	129,998	0.1	201
RP456	20	14,094	16.4	143,226	84.9	244,121
SK123	30	5,109	28.6	250,448	8.5	24,409
SK456	30	13,134	12.6	110,551	35.2	101,173
SL123	30	18,721	14.4	125,706	66.8	191,939

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Distribution Substation Transformer Losses

SUBSTATION NAME	TRANSFORMER BASE RATING (MVA)	2009 COINCIDENT PEAK LOAD (kW)	TRANSFORMER NO-LOAD LOSSES (kW) (1)(7)	ANNUAL (2) NO-LOAD ENERGY LOSSES (kWh)	TRANSFORMER LOAD LOSSES (kW) (3)	ANNUAL (4) LOAD ENERGY LOSSES (kWh)
SL456	30	23,354	28.5	249,222	121.3	348,658
SL789	30	11,877	14.8	129,569	28.7	82,572
SP123	30	16,770	13.4	117,743	91.8	263,786
SP789	30	25,241	14.8	129,560	138.9	399,374
SP012	30	25,593	13.9	121,703	145.9	419,557
SP345	70	20,739	20.1	175,726	28.1	80,847
SP678	70	20,674	20.0	175,200	34.2	98,183
SN-NT1	50	0	21.0	183,960	0.0	0
SN-NT2	50	25,900	21.0	183,960	71.3	204,876
ST123	30	18,457	14.2	124,742	62.8	180,582
ST456	30	19,436	10.5	91,630	83.9	241,303
ST789	30	21,628	14.7	129,044	100.5	288,799
SU012	50	5,757	20.6	180,456	3.0	8,596
SU123	30	13,748	11.6	101,791	37.1	106,550
SU345	30	24,489	13.4	117,743	133.4	383,475
SU456	30	19,739	12.1	105,558	19.4	55,862
SU789	50	14,845	20.6	180,456	19.4	55,862
SW123	30	24,626	28.7	251,587	141.8	407,654
SW456	30	22,669	28.0	245,280	132.6	381,204
SW789	30	21,969	29.0	254,390	109.4	314,560
TP123	30	18,405	9.9	86,724	65.4	188,115
TP456	30	21,088	12.6	110,551	81.5	234,317
TR123	30	22,032	13.1	114,590	114.5	329,280
TR456	30	14,947	13.4	117,743	54.4	156,518
TR789	30	12,787	12.9	113,004	38.8	111,466
VE123	50	22,296	15.5	135,430	46.0	132,253
WA123	30	26,216	25.6	224,431	218.8	629,120
WA456	30	21,197	25.5	223,292	136.5	392,416
WB123	50	3,900	15.0	131,277	1.4	4,140
WB456	50	1,848	20.9	183,513	0.4	1,006
WC012	30	14,463	11.6	101,966	38.0	109,252
WC789	30	16,226	9.9	86,286	60.1	172,676
WI012	30	12,523	11.5	100,565	35.9	103,214
WI123	40	25,984	21.0	183,697	100.7	289,374
WI456	40	27,800	22.4	196,136	127.7	367,087
WI789	30	21,896	15.4	135,079	98.8	284,113
WL123	30	14,631	21.6	189,216	41.3	118,682
WL456	30	25,130	15.3	133,678	118.7	341,125
WL789	30	22,079	13.1	114,774	104.2	299,638
TOTALS	5,169	2,506,883	2,613.3	22,892,596	10,075.4	28,967,223

Notes:
(1) From test reports provided by Austin Energy
(2) Annual No-Load Energy Losses is based on calculated demand losses times 8760 hours.
(3) Calculated in Feederall model with 2009 peak load flows
(4) Annual Load Energy Losses is based on transformer load losses, 8760 hours, and a loss factor calculated from the annual load factor
(5) No-Load Loss values were estimated based on the average No-Load Loss of th 30 MVA Transformers
(6) Load Loss values were estimated based on 30 MVA Transformers of simlar loading
(7) Units with no No-Load Losses are de-energized or out of service

Exhibit E
Distribution Line Losses

AUSTIN ENERGY

Evaluation of T&D System Losses

Estimated Primary Distribution Line Losses

DISTRIBUTION VOLTAGE (kV)	LENGTH OF LINE (Miles)	DEMAND LOSSES (1) AT 2009 PEAK (kW)	ANNUAL ENERGY LOSSES (kWh)
12.5(2)	4,810.0	36,186.0	104,036,747
TOTALS	4,810.0	36,186.0	104,036,747

Notes:
(1) Peak losses extracted from system model

Exhibit F
Distribution Transformer Losses

AUSTIN ENERGY
Evaluation of T&D System Losses

Estimated Distribution Transformer Losses

LOCATION	TOTAL NO-LOAD LOSSES (kW)	TOTAL LOAD LOSSES (kW)	NUMBER OF XFMRS	TOTAL XFMR kVA	TOTAL ANNUAL ENERGY NO-LOAD LOSS (kWh)	TOTAL ANNUAL ENERGY LOAD LOSS (kWh)
Distribution Transformers	15,969	7,583	86,179	6,483,472	139,886,152	21,802,583
TOTALS	15,969	7,583	86,179	6,483,472	139,886,152	21,802,583

Notes:
(1) Losses were estimated for each distribution transformer size based on the manufacturer test reports for similar sized transformers
(2) Transformer loading based on customer sales and total transformer capacity
(3) Results excludes primary metered transformers
(4) Calculated Transformer Loading Percentage 38.12%

Exhibit G
Distribution Transformer Specifications

Phasing	VOLTAGE (kV)	Transformer KVA	Test Report NLL (KW)	Test Report %R
1ph	12.5	1.5	0.008	1.52%
1ph	12.5	3.5	0.020	1.52%
1ph	12.5	5	0.030	1.52%
1ph	12.5	10	0.045	1.26%
1ph	12.5	15	0.059	1.13%
3ph	12.5	15	0.069	0.78%
1ph	12.5	25	0.086	0.99%
3ph	12.5	25	0.106	0.75%
1ph	12.5	37.5	0.120	0.93%
3ph	12.5	37.5	0.109	0.55%
1ph	12.5	50	0.148	0.86%
3ph	12.5	50	0.156	0.59%
1ph	12.5	75	0.210	0.83%
3ph	12.5	75	0.210	0.52%
1ph	12.5	100	0.261	0.36%
3ph	12.5	100	0.243	0.32%
3ph	12.5	112.5	0.280	0.33%
1ph	12.5	125	0.282	0.30%
3ph	12.5	150	0.345	0.31%
1ph	12.5	150	0.345	0.31%
1ph	12.5	167	0.305	0.19%
3ph	12.5	167	0.303	0.20%
1ph	12.5	175	0.321	0.19%
1ph	12.5	200	0.373	0.20%
3ph	12.5	225	0.428	0.20%
1ph	12.5	225	0.428	0.20%
1ph	12.5	250	0.547	0.14%
3ph	12.5	250	0.501	0.16%
3ph	12.5	300	0.570	0.15%
1ph	12.5	300	0.570	0.15%
3ph	12.5	333	0.572	0.07%
1ph	12.5	333	0.664	0.07%
3ph	12.5	500	0.850	0.07%
1ph	12.5	500	0.850	0.07%
3ph	12.5	750	1.200	0.05%
1ph	12.5	750	1.200	0.05%
3ph	12.5	1000	1.300	0.03%
3ph	12.5	1500	2.100	0.02%
1ph	12.5	1500	2.100	0.02%
3ph	12.5	1500	2.100	0.02%
3ph	12.5	2000	2.600	0.02%
3ph	12.5	2500	2.500	0.01%
3ph	12.5	5000	5.000	0.01%

Exhibit H
Secondary Line Losses

AUSTIN ENERGY
Evaluation of System Losses

Estimated Service Line Losses

Type	MILES OF CONDUCTOR	PERCENT CONDUCTOR PEAK LOADING/CAPACITY [1]	PEAK DEMAND LOSS (kW)	ANNUAL ENERGY LOSSES (kWh)
Service Conductor	3,019	31.3%	9,121	26,223,140
Secondary Conductor	1,714	31.3%	5,759	16,556,558
Streetlight Conductor	1,302	1.8%	6.3	9,021
TOTAL	6,034		14,886	42,788,719

Notes
(1) Conductor loading percentage is as follows:

Service Conductor = (Annual Energy Sales (kWh)-Streetlight Annual Energy Sales (kWh)) / (Time * Load Factor) / Conductor Capacity (kVA)

Secondary Conductor = Service Conductor

Streetlight Conductor = (Streetlight Annual Energy Sales (kWh) / (Time * Load Factor)) / Conductor Capacity (kVA)

Exhibit I
Security and Streetlight Losses

AUSTIN ENERGY
Evaluation of T&D System Losses

Estimated Street & Security Light Losses

SECURITY & STREET LIGHT SIZES	ASSUMED USAGE (2) (WATTS)	NUMBER OF LIGHTS FROM GIS	ASSUMED DEMAND (kW)	ANNUAL ENERGY CONSUMPTION (kWh)
70 Watt	85	79	6.7	29,412
75 Watt(1)	85	1	0.1	372
100 Watt	125	30,878	3,859.8	16,905,705
150 Watt	180	491	88.4	387,104
175 Watt	200	4,205	841.0	3,683,580
250 Watt	280	16,850	4,718.0	20,664,840
400 Watt	450	5,468	2,460.6	10,777,428
1000 Watt	1,100	82	90.2	395,076
1500 Watt	1,600	10	16.0	70,080
4000 Watt (1)	4,200	1	4.2	18,396
Unknown(3)	125	5,430	678.8	2,972,925
TOTALS		63,495	12,763.7	55,904,918
TOTAL BILLED kWh(4)				52,204,770
UNACCOUNTED FOR LIGHT CONSUMPTION				3,700,148

Notes:
(1) Assumed wattage was not provided by AE
(2) Amount charged by AE accounts for light and ballast
(3) Unknown is assumed to be 100 watts
(4) Annual energy billed was provided by AE's offical report
(5) Estimated 12 hours of operation per day

Exhibit J
System Loss Graphics

AUSTIN ENERGY
Evaluation of T&D System Losses

T&D Energy Losses by Voltage

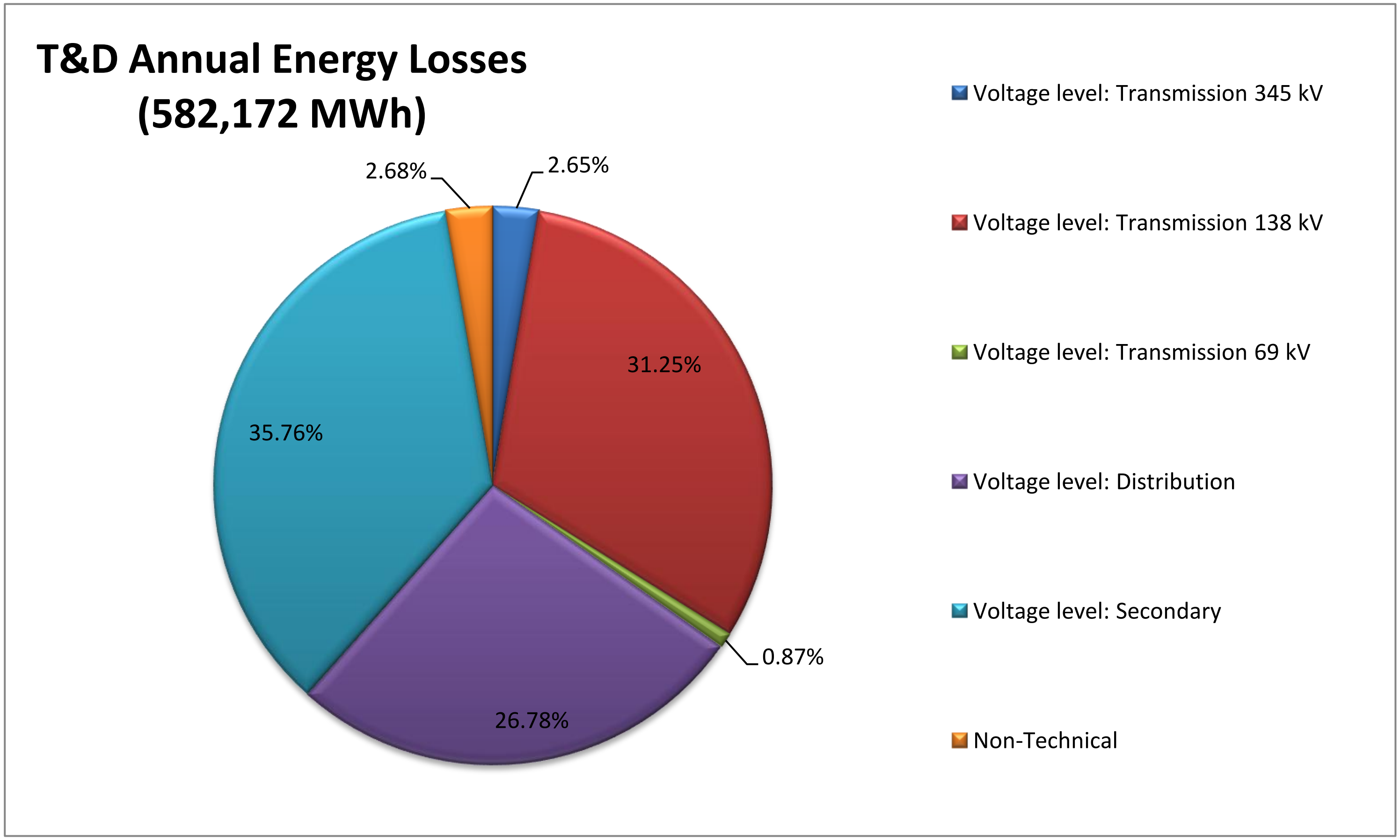


Exhibit J
System Loss Graphics

AUSTIN ENERGY
Evaluation of T&D System Losses

T&D Energy Losses by Equipment Type

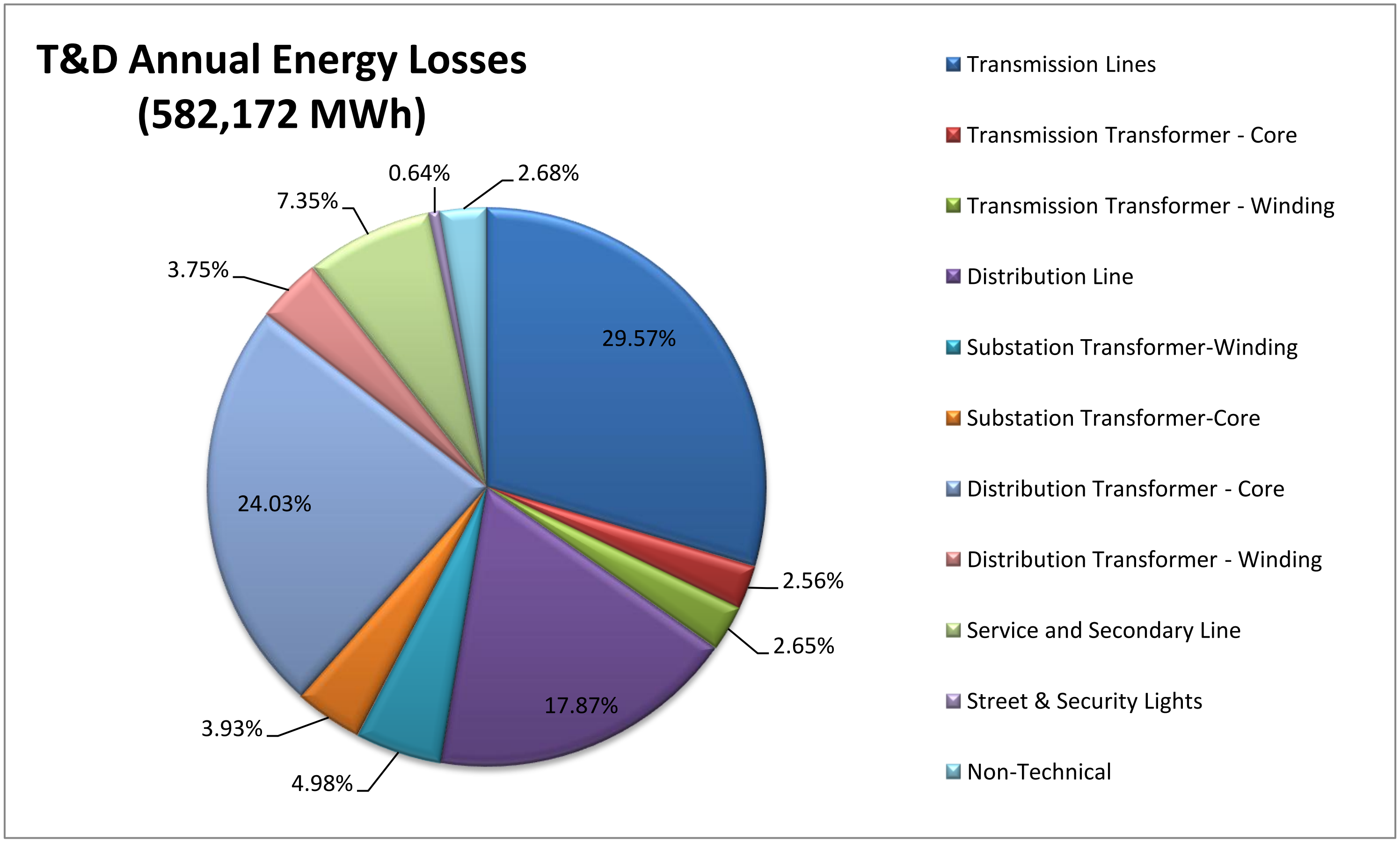


Exhibit J
System Loss Graphics

AUSTIN ENERGY
Evaluation of T&D System Losses

T&D Demand Losses by Voltage

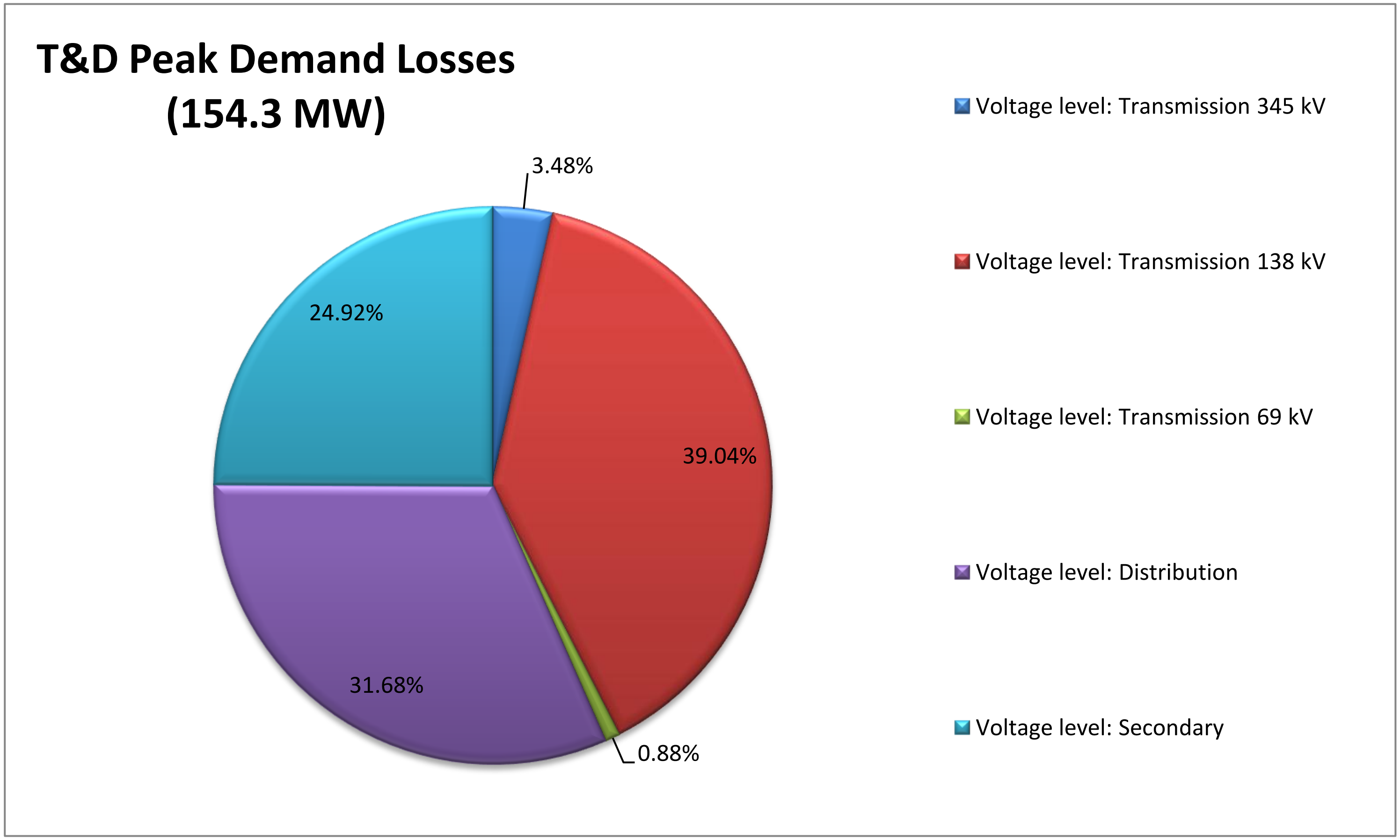
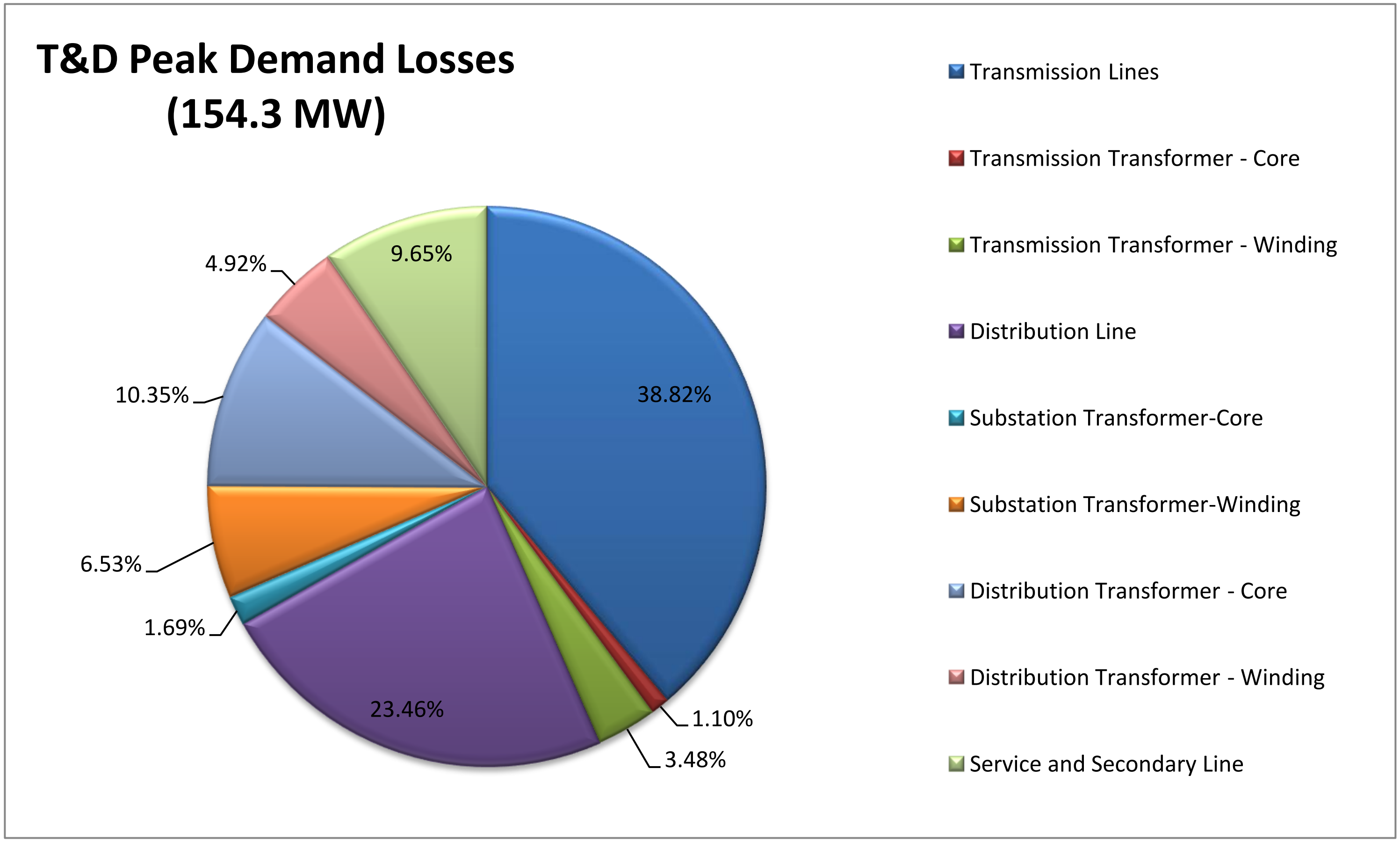


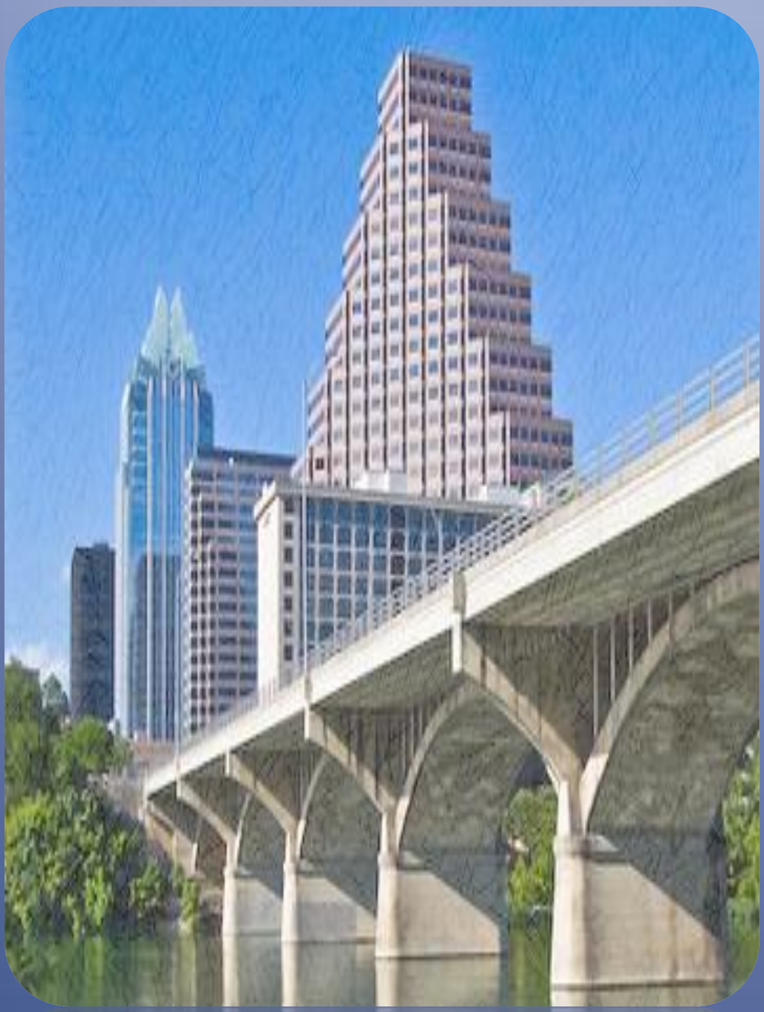
Exhibit J
System Loss Graphics

AUSTIN ENERGY

Evaluation of T&D System Losses

T&D Demand Losses by Equipment Type





City of Austin Electric Tariff

Effective Date: October 1, 2016

Approved on June X, 2016, by the Austin City Council Members:
Mayor Steve Adler, Mayor Pro Tem Kathie Tovo (District 9), Council Member Ora Houston (District 1), Council Member Delia Garza (District 2), Council Member Sabino Renteria (District 3), Council Member Gregorio Casar (District 4), Council Member Ann Kitchen (District 5), Council Member Don Zimmerman (District 6), Council Member Leslie Pool (District 7), Council Member Ellen Troxclair (District 8), and Council Member Sheri Gallo (District 10).

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Residential Service

Application:
Applies to all electric service for domestic purposes in each individual metered residence, apartment unit, mobile home, or other dwelling unit whose point of delivery is located within the limits of Austin Energy's service territory. The appropriate General Service schedules applies where a portion of the dwelling unit is used for either: a) conducting a business, or other non-domestic purposes, unless such use qualifies as a home occupation pursuant to City Code Chapter 25-2-900; or b) for separately-metered uses at the same premises, including, but not limited to: water wells, gates, barns, garages, boat docks, pools, and lighting. These rates apply to secondary voltage less than 12,470 volts nominal line to line.

Character of Service:
Service is provided under this rate schedule pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and allow reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

The rate tables below reflect rates with an effective date of October 1, 2016. For information on other applicable rates (i.e., power supply adjustment, community benefit, and regulatory), please see corresponding schedules in this tariff (if applicable). For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Discounts:
Residential customers who receive, or who reside with a household member who receives, assistance from the Comprehensive Energy Assistance Program (CEAP), Travis County Hospital District Medical Assistance Program (MAP), Supplemental Security Income Program (SSI), Medicaid, Veterans Affairs Supportive Housing (VASH), the Supplemental Nutritional Assistance Program (SNAP), the Children's Health Insurance Program (CHIP), or the Telephone Lifeline Program are eligible for a discount under the Customer Assistance Program (CAP). The priority for program funding is CEAP, MAP, SSI, Medicaid, VASH, and SNAP followed by CHIP and then Telephone Lifeline recipients. Eligible residential customers will be automatically enrolled in the discount program through a third-party matching process, with self-enrollment also available directly through Austin Energy.

Customers enrolled in the discount program are exempt from the monthly Customer Charge and the CAP component of the Community Benefit Charge and shall receive a 10 percent bill reduction on kilowatt-hour-based charges. Customers in the discount program, as well as other low income and disadvantaged residential customers, may be eligible for bill payment assistance through Plus 1 and for free weatherization assistance.

Rider Schedules:
Service under this rate schedule is eligible for application of GreenChoice® Energy (Rider) and Value-Of-Solar (Rider).

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	Outside City Limits
Basic Charges ($/month)		
Customer	$10.00	$10.00
Delivery	$0.00	$0.00
Energy Charges ($/kWh)		
0 – 500 kWh	$0.03300	$0.03800
501 – 1,000 kWh	$0.05600	$0.05600
1,001 – 1,500 kWh	$0.07595	$0.07815
1,501 – 2,500 kWh	$0.09100	$0.07815
Over 2,500 kWh	$0.10595	$0.07815
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03148	$0.03148
Non-Summer Power Supply (Oct – May)	$0.03124	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00172	$0.00118
Service Area Lighting	$0.00145	$0.00000
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kWh)		
Regulatory	$0.01159	$0.01159

Time-Of-Use Rates

Austin Energy has administratively suspended availability of this time-of-use rate option to additional customers; while this rate option is closed, Austin Energy offers a time-of-use option under the pilot program rate schedule. If already participating in the programs, customers will have chosen the time-of-use charges to be applied for a term of no less than twelve consecutive billing months, in lieu of the Standard Rates that apply to all of Austin Energy's service territory. Customers selecting this option are not eligible to participate in levelized billing.

Time-Of-Use Periods

	Summer (June through September)	**Non-Summer** (October through May)
On-Peak Hours		
2:00 P.M. – 8:00 P.M.	Monday – Friday	None
Mid-Peak Hours		
6:00 A.M. – 2:00 P.M.	Monday – Friday	
8:00 P.M. – 10:00 P.M.	Monday – Friday	
6:00 A.M. – 10:00 P.M.	Saturday and Sunday	Everyday

Off-Peak Hours		
10:00 P.M. – 6:00 A.M.	Everyday	Everyday

<u>*Time-Of-Use Charges*</u>

		Summer (June through September)	**Non-Summer** (October through May)
Basic Charges ($/month)			
Customer		$12.00	$12.00
Delivery		$0.00	$0.00
Total Energy Charges ($/kWh)			
0 – 500 kWh			
	Off-Peak	$0.00493	($0.00924)
	Mid-Peak	$0.05040	$0.01201
	On-Peak	$0.09761	$0.09761
501 – 1,000 kWh			
	Off-Peak	$0.01188	($0.00427)
	Mid-Peak	$0.06218	$0.03673
	On-Peak	$0.11003	$0.11003
1,001 – 1,500 kWh			
	Off-Peak	$0.02182	($0.00014)
	Mid-Peak	$0.07134	$0.04891
	On-Peak	$0.12196	$0.12196
1,501 – 2,500 kWh			
	Off-Peak	$0.02679	$0.00692
	Mid-Peak	$0.07934	$0.06282
	On-Peak	$0.13031	$0.13031
Over 2,500 kWh			
	Off-Peak	$0.06158	$0.04170
	Mid-Peak	$0.09512	$0.09761
	On-Peak	$0.14979	$0.14979
Power Supply Adjustment Charge ($/kWh)			
Power Supply		$0.03148	$0.03124
Community Benefit Charges ($/kWh)			
Customer Assistance Program			
	Inside City Limits	$0.00172	$0.00172
	Outside City Limits	$0.00118	$0.00118
Service Area Lighting *(Only applies to Inside City Limits Accounts)*		$0.00145	$0.00145
Energy Efficiency Services		$0.00246	$0.00246
Regulatory Charge ($/kWh)			

Regulatory	$0.01159	$0.01159

General Service

Application:
Applies to all metered, non-residential secondary voltage electric service whose point of delivery is located within the limits of Austin Energy's service territory. These rates apply to secondary voltage less than 12,470 volts nominal line to line.

Character of Service:
Service is provided under these rate schedules pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

All demand (kW) is referred to as "Billed kW" and shall be measured as the metered kilowatt demand during the fifteen-minute interval of greatest use during the billing month as determined by Austin Energy's metering equipment and adjusted for power factor and load factor corrections.

When power factor during the interval of greatest use is less than 90 percent, as determined by metering equipment installed by Austin Energy, the Billed kW shall be determined by multiplying metered kilowatt demand during the fifteen-minute interval of greatest use by a 90 percent power factor divided by the actual recorded power factor during the interval of greatest use.

For example, the metered kilowatt demand during the fifteen-minute interval of greatest monthly use is 13.5 kW, and the power factor during the fifteen-minute interval of greatest monthly use is 86.7 percent; therefore, the Billed kW equals 14.0 kW (13.5 kW x 0.90 / 0.867 power factor).

When the customer's monthly load factor is below 20 percent, the Billed kW will be reduced to the level required to provide an effective load factor of 20 percent. Load factor is calculated as metered energy divided by Billed kW multiplied by number of hours within the billing month. Load factor is only for determining your Billed kW, not your placement within the proper rate schedule.

For example, assuming a customer had metered energy of 1,152 kWh, Billed kW of 16 kW, and 720 hours in the billing month, the load factor would be 10 percent [1,152 kWh ÷ (16 kW * 720 hours)]; therefore, to equal a 20 percent load factor the Billed kW would need to be reduced to 8 kW [1,152 kWh ÷ (20 percent load factor * 720 hours)].

The rate tables below reflect rates with an effective date of October 1, 2016. For information on other applicable rates (i.e., power supply adjustment, community benefit, and regulatory), please see corresponding schedules in this tariff (if applicable). For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Time-Of-Use Option

Austin Energy has administratively suspended availability of this time-of-use rate option to additional customers. If already participating in the programs, customers will have chosen the time-of-use charges to be applied for a term of no less than twelve consecutive billing months, in lieu of the Standard Rates that apply to all of Austin Energy's service territory. Customers selecting this option are not eligible to participate in levelized billing.

Time-Of-Use Periods

	Summer (June through September)	**Non-Summer** (October through May)
On-Peak Hours		
2:00 P.M. – 8:00 P.M.	Monday – Friday	None
Mid-Peak Hours		
6:00 A.M. – 2:00 P.M.	Monday – Friday	
8:00 P.M. – 10:00 P.M.	Monday – Friday	
6:00 A.M. – 10:00 P.M.	Saturday and Sunday	Everyday
Off-Peak Hours		
10:00 P.M. – 6:00 A.M.	Everyday	Everyday

Discounts:
For any Independent School District, Military accounts as outlined in the Public Utility Regulatory Act §36.354, or State facilities the monthly customer-, delivery-, demand-, and energy-charges billed pursuant to these rate schedules will be discounted by 20 percent; all other electric charges will be billed pursuant to these rate schedules and will not be discounted.

GreenChoice® Energy Rider:
Service under these rate schedules is eligible for application of the GreenChoice® Energy (Rider).

Secondary Voltage (Demand less than 10 kW)

These rates apply to any customer whose average metered peak demand for power during the most recent June through September billing months did not meet or exceed 10 kW. If a customer has insufficient usage history to determine the appropriate rate schedule, Austin Energy will place the customer. Demand data will be reviewed annually in October.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	**Outside City Limits**
Basic Charges ($/month)		
Customer	$18.00	$18.00
Delivery	$0.00	$0.00
Energy Charges ($/kWh)		
All Billed kWhs	$0.05190	$0.05190

Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03148	$0.03148
Non-Summer Power Supply (Oct – May)	$0.03124	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00145	$0.00000
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kWh)		
Regulatory	$0.01159	$0.01159

Time-Of-Use Rates

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges ($/month)		
Customer	$18.00	$18.00
Delivery	$0.00	$0.00
Total Energy Charges ($/kWh)		
Off-Peak	$0.00798	$0.00798
Mid-Peak	$0.06336	$0.06336
On-Peak	$0.12437	$0.12437
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03148	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00145	$0.00145
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kWh)		
Regulatory	$0.01159	$0.01159

Secondary Voltage (Demand greater than or equal to 10 kW but less than 300 kW)

These rates apply to any customer whose average metered peak demand for power during the most recent June through September billing months met or exceeded 10 kW but did not meet or exceed 300 kW. If a customer has insufficient usage history to determine the appropriate rate schedule, Austin Energy will place the customer. Demand data will be reviewed annually in October.

These rates shall apply for no less than twelve months following the last month in which the required average summer metered peak demand level was met. The twelve month requirement may be waived by Austin Energy, if a customer has made significant changes in their connected load, which prevents the customer from meeting or exceeding the minimum-metered demand threshold of this rate schedule and Austin Energy has verified these changes.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	**Outside City Limits**
Basic Charges		
Customer ($/month)	$27.50	$27.50
Delivery ($/kW)	$4.00	$4.00
Demand Charges ($/kW)		
All Billed kWs	$5.75	$5.75
Energy Charges *($/kWh)*		
All Billed kWhs	$0.02421	$0.02356
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03148	$0.03148
Non-Summer Power Supply (Oct – May)	$0.03124	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00145	$0.00000
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kW)		
Regulatory	$3.24	$3.24

Time-Of-Use Rates

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$27.50	$27.50
Delivery ($/kW)	$4.00	$4.00
Demand Charges ($/kW)		
All Billed kWs	$5.75	$5.75
Energy Charges ($/kWh)		
Off-Peak	($0.00067)	($0.00067)
Mid-Peak	$0.03912	$0.03912
On-Peak	$0.06544	$0.06544

Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03148	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00145	$0.00145
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kW)		
Regulatory	$3.24	$3.24

Secondary Voltage (Demand greater than or equal to 300 kW)

These rates apply to any customer whose average metered peak demand for power during the most recent June through September billing months met or exceeded 300 kW. If a customer has insufficient usage history to determine the appropriate rate schedule, Austin Energy will place the customer. Demand data will be reviewed annually in October.

These rates shall apply for not less than twelve months following the last month in which the required average summer metered peak demand level was met. The twelve month requirement may be waived by Austin Energy, if a customer has made significant changes in their connected load, which prevents the customer from meeting or exceeding the minimum-metered demand threshold of this rate schedule and Austin Energy has verified these changes.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	Outside City Limits
Basic Charges		
Customer ($/month)	$71.50	$71.50
Delivery ($/kW)	$4.50	$4.50
Demand Charges ($/kW)		
All Billed kWs	$7.25	$7.25
Energy Charges *($/kWh)*		
All Billed kWhs	$0.01955	$0.01902
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03148	$0.03148
Non-Summer Power Supply (Oct – May)	$0.03124	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00145	$0.00000

Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kW)		
Regulatory	$3.24	$3.24

Time-Of-Use Rates

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$71.50	$71.50
Delivery ($/kW)	$4.50	$4.50
Demand Charges ($/kW)		
All Billed kWs	$7.25	$7.25
Energy Charges ($/kWh)		
Off-Peak	($0.00222)	($0.00222)
Mid-Peak	$0.03565	$0.03565
On-Peak	$0.06070	$0.06070
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03148	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00145	$0.00145
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kW)		
Regulatory	$3.24	$3.24

Large General Service

Application:
Applies to all primary voltage electric service whose point of delivery is located within the limits of Austin Energy's service territory. These rates apply to primary voltage between 12,470 and 69,000 volts nominal line to line.

Character of Service:
Service is provided under these rate schedules pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
The customer shall own, maintain, and operate all facilities and equipment on the customer's side of the point of delivery. Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

All demand (kW) is referred to as "Billed kW" and shall be measured as the metered kilowatt demand during the fifteen-minute interval of greatest use during the billing month as determined by Austin Energy's metering equipment and adjusted for power factor corrections.

When the power factor during the interval of greatest use is less than 90 percent, as determined by metering equipment installed by Austin Energy, the Billed kW shall be determined by multiplying the metered kilowatt demand during the fifteen-minute interval of greatest use by a 90 percent power factor divided by the actual recorded power factor during the interval of greatest use.

For example, the metered kilowatt demand during the fifteen-minute interval of greatest monthly use is 10,350 kW, and the power factor during the fifteen-minute interval of greatest monthly use is 86.7 percent; therefore, the Billed kW equals 10,744 kW (10,350 kW x 0.90 / 0.867 power factor).

The rate tables below reflect rates with an effective date of October 1, 2016. For information on other applicable rates (i.e., power supply adjustment, community benefit, and regulatory), please see corresponding schedules in this tariff (if applicable). For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Time-Of-Use Rates:
Austin Energy has administratively suspended availability of this time-of-use rate option to additional customers. If already participating in the programs, customers will have chosen the time-of-use charges to be applied for a term of no less than twelve consecutive billing months, in lieu of the Standard Rates that apply to all of Austin Energy's service territory. Customers selecting this option are not eligible to participate in levelized billing.

Time-Of-Use Periods:

	Summer (June through September)	**Non-Summer** (October through May)

On-Peak Hours		
2:00 P.M. – 8:00 P.M.	Monday – Friday	None
Mid-Peak Hours		
6:00 A.M. – 2:00 P.M.	Monday – Friday	
8:00 P.M. – 10:00 P.M.	Monday – Friday	
6:00 A.M. – 10:00 P.M.	Saturday and Sunday	Everyday
Off-Peak Hours		
10:00 P.M. – 6:00 A.M.	Everyday	Everyday

Discounts:
For any Independent School District, Military accounts as outlined in the Public Utility Regulatory Act §36.354, or State facilities the monthly customer-, delivery-, demand-, and energy-charges billed pursuant to these rate schedules will be discounted by 20 percent; all other electric charges will be billed pursuant to these rate schedules and will not be discounted.

GreenChoice® Energy Rider:
Service under these rate schedules is eligible for application of the GreenChoice® Energy (Rider).

Primary Voltage (Demand less than 3 MW)

These rates apply to any customer whose average metered peak demand for power during the most recent June through September billing months did not meet or exceed 3,000 kW. If a customer has insufficient usage history to determine the appropriate rate schedule, Austin Energy will place the customer. Demand data will be reviewed annually in October.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	Outside City Limits
Basic Charges		
Customer ($/month)	$275.00	$275.00
Delivery ($/kW)	$3.50	$3.50
Demand Charges ($/kW)		
All Billed kWs	$8.50	$8.50
Energy Charges *($/kWh)*		
All Billed kWhs	$0.00500	$0.00487
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03076	$0.03076
Non-Summer Power Supply (Oct – May)	$0.03053	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065

Service Area Lighting	$0.00141	$0.00000
Energy Efficiency Services	$0.00240	$0.00240
Regulatory Charge ($/kW)		
Regulatory	$3.16	$3.16

Time-Of-Use Rates

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$275.00	$275.00
Delivery ($/kW)	$3.50	$3.50
Demand Charges ($/kW)		
All Billed kWs	$8.50	$8.50
Energy Charges ($/kWh)		
Off-Peak	($0.00862)	($0.00862)
Mid-Peak	$0.02042	$0.02042
On-Peak	$0.03963	$0.03963
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03076	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00141	$0.00141
Energy Efficiency Services	$0.00240	$0.00240
Regulatory Charge ($/kW)		
Regulatory	$3.16	$3.16

Primary Voltage (Demand greater than or equal to 3 MW and less than 20 MW)

These rates apply to any customer whose average metered peak demand for power during the most recent June through September billing months met or exceeded 3,000 kW but did not meet or exceed 20,000 kW. If a customer has insufficient usage history to determine the appropriate rate schedule, Austin Energy will place the customer. Demand data will be reviewed annually in October.

These rates shall apply for no less than twelve months following the last month in which the required average summer metered peak demand level was met. The twelve month requirement may be waived by Austin Energy, if a customer has made significant changes in their connected load, which prevents the customer from meeting or exceeding the minimum-metered kW threshold of this rate schedule and Austin Energy has verified these changes. Dual Feed Service charges are not applicable to this rate schedule.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	Outside City Limits
Basic Charges		
Customer ($/month)	$2,200.00	$2,200.00
Delivery ($/kW)	$4.00	$4.00
Demand Charges ($/kW)		
All Billed kWs	$9.50	$9.50
Energy Charges ($/kWh)		
All Billed kWhs	$0.00360	$0.00350
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03076	$0.03076
Non-Summer Power Supply (Oct – May)	$0.03053	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00141	$0.00000
Energy Efficiency Services	$0.00240	$0.00240
Regulatory Charge ($/kW)		
Regulatory	$3.16	$3.16

Time-Of-Use Rates

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$2,200.00	$2,200.00
Delivery ($/kW)	$4.00	$4.00
Demand Charges ($/kW)		
All Billed kWs	$9.50	$9.50
Energy Charges ($/kWh)		
Off-Peak	($0.01211)	($0.01211)
Mid-Peak	$0.01263	$0.01263
On-Peak	$0.02899	$0.02899
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03076	$0.03053

Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00141	$0.00141
Energy Efficiency Services	$0.00240	$0.00240
Regulatory Charge ($/kW)		
Regulatory	$3.16	$3.16

Primary Voltage (Demand greater than or equal to 20 MW)

This rate apply to any customer whose average metered peak demand for power during the most recent June through September billing months met or exceeded 20,000 kW. If a customer has insufficient usage history to determine the appropriate rate schedule, Austin Energy will place the customer. Demand data will be reviewed annually in October.

This rate shall apply for no less than twelve months following the last month in which the required average summer metered peak demand level was met. The twelve month requirement may be waived by Austin Energy, if a customer has made significant changes in their connected load, which prevents the customer from meeting or exceeding the minimum metered kW threshold of this rate schedule and these changes have been verified by Austin Energy. Dual Feed Service charges are not applicable to this rate schedule.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	Outside City Limits
Basic Charges		
Customer ($/month)	$2,750.00	$2,750.00
Delivery ($/kW)	$4.50	$4.50
Demand Charges ($/kW)		
All Billed kWs	$10.25	$10.25
Energy Charges ($/kWhs)		
All Billed kWhs	$0.00300	$0.00300
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03076	$0.03076
Non-Summer Power Supply (Oct – May)	$0.03053	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00141	$0.00000
Energy Efficiency Services	$0.00240	$0.00240

Regulatory Charge ($/kW)		
Regulatory	$3.16	$3.16

Time-Of-Use Rates

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$2,750.00	$2,750.00
Delivery ($/kW)	$4.50	$4.50
Demand Charges ($/kW)		
All Billed kWs	$10.25	$10.25
Energy Charges ($/kWh)		
Off-Peak	($0.01302)	($0.01302)
Mid-Peak	$0.01057	$0.01057
On-Peak	$0.02618	$0.02618
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03076	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00141	$0.00141
Energy Efficiency Services	$0.00240	$0.00240
Regulatory Charge ($/kW)		
Regulatory	$3.16	$3.16

High Load Factor Primary Voltage (Demand greater than or equal to 20 MW)

This rate apply to any customer whose average monthly billed demand for power met or exceeded 20,000 kW and has an annual average monthly load factor of at least 85 percent.

Contract Term:
For a term ending at the end of the billing month that includes October 31, 2024, the customer shall enter into an exclusive sole supplier agreement to purchase its entire bundled electric service requirements for the facilities and equipment at the account service location, with an exception for on-site back-up generation and up to 1 MW of on-site renewable generation capacity. The City Manager or his designee may establish and agree to terms and conditions for a service contract.

Block Power Supply Pricing:

In lieu of the Power Supply Adjustment, the customer's service contract may provide a fixed power supply charge for a monthly block quantity of energy for a defined term, based on the cost of wholesale power market prices. Block pricing is contingent on the availability of authorized funding and the customer's satisfaction of credit requirements. All billed energy not subject to block pricing is subject to the variable Power Supply Adjustment (or Green Choice Energy rider), as may be amended from time to time, or any other successor power or fuel adjustment schedules.

The kWh block price shall be the actual wholesale kWh cost to Austin Energy of the block quantity supplied, plus a renewable portfolio charge based upon the forecast kWh price of renewable energy credits in the ERCOT market during the term of the block pricing.

In lieu of the renewable portfolio charge, the customer may opt to designate an equal renewable portfolio dollar value as a monthly block quantity of GreenChoice Energy by paying the per-kWh price difference between the wholesale power price paid by Austin Energy and the applicable GreenChoice Charge for the specified quantity.

Minimum Bill:
The minimum monthly bill is the highest billed demand established during the most recent 12-month billing period multiplied by the Summer Demand Charge, in addition to any associated fuel, power supply, or block pricing charges.

Maximum Community Benefit Charges:
During the term of a service contract, Customer Assistance Program charges shall not exceed $200,000 during any fiscal year of October 1 through September 30 (prorated for any partial fiscal year). Charges for Service Area Lighting and Energy Efficiency Services (EES) do not apply under this rate schedule.

Terms and Conditions:
This schedule is effective through the end of the customer's billing month that includes October 31, 2024. Austin Energy may provide service under this schedule as a bundled entity or, if retail deregulation is implemented in its service area, as separate, unbundled entities. The customer is ineligible for participation in energy efficiency, retail demand response, and renewable energy incentive programs. Billed amounts due and owing shall incur a penalty of one percent per month until paid.

Average annual monthly load factor is the sum of the customer's load factor percentages for the previous twelve billing months divided by twelve. Verified reductions in energy consumption made in response to a request for Emergency Response Service or another demand response program operated by ERCOT shall be credited in calculating load factor. Dual Feed Service charges are not applicable to this rate schedule.

Standard Rates

Basic, energy, demand, and community benefits charges will be fixed for the initial contract period ending October 31, 2018. The Austin City Council may amend these charges to be fixed for the period November 1, 2018, through October 31, 2021, and again for the period November 1, 2021, through October 31, 2024.

If, during the initial contract period ending October 31, 2018, the City Council adopts new base electric rates for customers receiving service at primary voltage based upon a comprehensive cost-of-service study, the customer may opt to have its contract rates adjusted to any applicable new rates during the initial contract term.

Regulatory charge will remain fixed for the initial contract period ending October 31, 2018. For each subsequent three-year period, the regulatory charge will be reset and fixed in accordance with the regulatory charge schedule, plus an adjustment for any over- or under-recovery of regulatory charges from the previous three-year period. The regulatory charge may be adjusted during any three-year period if an over-recovery of more than 110 percent or an under-recovery of less than 90 percent of costs occurs.

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$15,470.00	$15,470.00
Delivery ($/kW)	$4.50	$4.50
Demand Charges ($/kW)		
All Billed kWs	$11.58	$11.58
Energy Charges ($/kWh)		
All Billed kWhs	$0.00000	$0.00000
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03076	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Regulatory Charge ($/kW)		
All Billed kWs	$3.91	$3.91

For sign contract agreements with effective dates before October 1, 2016.

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$12,000.00	$12,000.00
Delivery ($/kW)	$3.75	$3.75
Demand Charges ($/kW)		
All Billed kWs	$11.10	$11.10
Energy Charges ($/kWh)		
All kWhs	$0.00370	$0.00370
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03076	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Regulatory Charges ($/kW)		
All Billed kWs	$5.18	$5.18

Transmission Service

Application:
Applies to all transmission voltage electric service at 69,000 volts or above nominal line to line, and whose point of delivery is located within the limits of Austin Energy's service territory.

Character of Service:
Service is provided under this rate schedule pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
The customer shall own, maintain, and operate all facilities and equipment on the customer's side of the point of delivery. Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

All demand (kW) is referred to as "Billed kW" and shall be measured as the metered kilowatt demand during the fifteen-minute interval of greatest use during the billing month as determined by Austin Energy's metering equipment, adjusted for power factor corrections.

When the power factor during the interval of greatest use is less than 90 percent, as determined by metering equipment installed by Austin Energy, the Billed kW shall be determined by multiplying metered kilowatt demand during the fifteen-minute interval of greatest use by a 90 percent power factor divided by the actual recorded power factor during the interval of greatest use.

For example, the metered kilowatt demand during the fifteen-minute interval of greatest monthly use is 31,000 kW, and the power factor during the fifteen-minute interval of greatest monthly use is 86.7 percent; therefore, the Billed kW equals 32,180 kW (31,000 kW x 0.90 / 0.867 power factor).

The rate tables below reflect rates with an effective date of October 1, 2016. For information on other applicable rates (i.e., power supply adjustment, community benefit, and regulatory), please see corresponding schedules in this tariff (if applicable). For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Discounts:
For any Independent School District, Military accounts as outlined in the Public Utility Regulatory Act §36.354, or State facilities the monthly customer-, delivery-, demand-, and energy-charges billed pursuant to these rate schedules will be discounted by 20 percent; all other electric charges will be billed pursuant to these rate schedules and will not be discounted.

GreenChoice® Energy Rider:
Service under this rate schedule is eligible for application of the GreenChoice® Energy (Rider).

Transmission Voltage

These rates apply to any customer whose metered demand is at 69,000 volts or above nominal line to line.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	Outside City Limits
Basic Charges		
Customer ($/month)	$2,750.00	$2,750.00
Delivery ($/kW)	$0.00	$0.00
Demand Charges ($/kW)		
All Billed kWs	$12.00	$12.00
Energy Charges *($/kWh)*		
All Billed kWhs	$0.00500	$0.00500
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03037	$0.03037
Non-Summer Power Supply (Oct – May)	$0.03015	$0.03015
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00140	$0.00000
Energy Efficiency Services	$0.00237	$0.00237
Regulatory Charge ($/kW)		
Regulatory	$3.12	$3.12

Time-Of-Use Rates

Austin Energy has administratively suspended availability of this time-of-use rate option to additional customers. If already participating in the programs, customers will have chosen the time-of-use charges to be applied for a term of no less than twelve consecutive billing months, in lieu of the Standard Rates that apply to all of Austin Energy's service territory. Customers selecting this option are not eligible to participate in levelized billing.

Time-Of-Use Periods

	Summer (June through September)	**Non-Summer** (October through May)
On-Peak Hours		
2:00 P.M. – 8:00 P.M.	Monday – Friday	None
Mid-Peak Hours		
6:00 A.M. – 2:00 P.M.	Monday – Friday	

8:00 P.M. – 10:00 P.M.	Monday – Friday	
6:00 A.M. – 10:00 P.M.	Saturday and Sunday	Everyday
Off-Peak Hours		
10:00 P.M. – 6:00 A.M.	Everyday	Everyday

Time-Of-Use Charges

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$2,750.00	$2,750.00
Delivery ($/kW)	$0.00	$0.00
Demand Charges ($/kW)		
All Billed kWs	$12.00	$12.00
Energy Charges ($/kWh)		
Off-Peak	($0.00974)	($0.00974)
Mid-Peak	$0.01741	$0.01741
On-Peak	$0.03537	$0.03537
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03037	$0.03015
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00140	$0.00140
Energy Efficiency Services	$0.00237	$0.00237
Regulatory Charge ($/kW)		
Regulatory	$3.12	$3.12

High Load Factor Transmission Voltage (Demand greater than or equal to 20 MW)

This rate apply to any customer whose average monthly billed demand for power met or exceeded 20,000 kW and has an annual average monthly load factor of at least 85 percent.

Contract Term:
For a term ending at the end of the billing month that includes October 31, 2024, the customer shall enter into an exclusive sole supplier agreement to purchase its entire bundled electric service requirements for the facilities and equipment at the account service location, with an exception for on-site back-up generation and up to 1 MW of on-site renewable generation capacity. The City Manager or his designee may establish and agree to terms and conditions for a service contract.

<u>*Block Power Supply Pricing:*</u>
In lieu of the Power Supply Adjustment, the customer's service contract may provide a fixed power supply charge for a monthly block quantity of energy for a defined term, based on the cost of wholesale power market prices. Block pricing is contingent on the availability of authorized funding and the customer's satisfaction of credit requirements. All billed energy not subject to block pricing is subject to the variable Power Supply Adjustment (or Green Choice Energy rider), as may be amended from time to time, or any other successor power or fuel adjustment schedules.

The kWh block price shall be the actual wholesale kWh cost to Austin Energy of the block quantity supplied, plus a renewable portfolio charge based upon the forecast kWh price of renewable energy credits in the ERCOT market during the term of the block pricing.

In lieu of the renewable portfolio charge, the customer may opt to designate an equal renewable portfolio dollar value as a monthly block quantity of GreenChoice Energy by paying the per-kWh price difference between the wholesale power price paid by Austin Energy and the applicable GreenChoice Charge for the specified quantity.

<u>*Minimum Bill:*</u>
The minimum monthly bill is the highest billed demand established during the most recent 12-month billing period multiplied by the Summer Demand Charge, in addition to any associated fuel, power supply, or block pricing charges.

<u>*Maximum Community Benefit Charges:*</u>
During the term of a service contract, Customer Assistance Program charges shall not exceed $200,000 during any fiscal year of October 1 through September 30 (prorated for any partial fiscal year). Charges for Service Area Lighting and Energy Efficiency Services (EES) do not apply under this rate schedule.

<u>*Terms and Conditions:*</u>
This schedule is effective through the end of the customer's billing month that includes October 31, 2024. Austin Energy may provide service under this schedule as a bundled entity or, if retail deregulation is implemented in its service area, as separate, unbundled entities. The customer is ineligible for participation in energy efficiency, retail demand response, and renewable energy incentive programs. Billed amounts due and owing shall incur a penalty of one percent per month until paid.

Average annual monthly load factor is the sum of the customer's load factor percentages for the previous twelve billing months divided by twelve. Verified reductions in energy consumption made in response to a request for Emergency Response Service or another demand response program operated by ERCOT shall be credited in calculating load factor.

Standard Rates

Basic, energy, demand, and community benefits charges will be fixed for the initial contract period ending October 31, 2018. The Austin City Council may amend these charges to be fixed for the period November 1, 2018, through October 31, 2021, and again for the period November 1, 2021, through October 31, 2024.

If, during the initial contract period ending October 31, 2018, the City Council adopts new base electric rates for customers receiving service at transmission voltage based upon a comprehensive cost-of-service study, the customer may opt to have its contract rates adjusted to any applicable new rates during the initial contract term.

Regulatory charge will remain fixed for the initial contract period ending October 31, 2018. For each subsequent three-year period, the regulatory charge will be reset and fixed in accordance with the regulatory charge schedule, plus an adjustment for any over- or under-recovery of regulatory charges from the previous three-year period. The regulatory charge may be adjusted during any three-year period if an over-recovery of more than 110 percent or an under-recovery of less than 90 percent of costs occurs.

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$21,120.00	$21,120.00
Demand Charges ($/kW)		
All Billed kWs	$11.41	$11.41
Energy Charges ($/kWh)		
All Billed kWhs	$0.00115	$0.00115
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03037	$0.03015
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Regulatory Charge ($/kW)		
All Billed kWs	$3.98	$3.98

For sign contract agreements with effective dates before October 1, 2016.

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$2,500.00	$2,500.00
Demand Charges ($/kW)		
All Billed kWs	$10.06	$9.10
Energy Charges ($/kWh)		
All Billed kWhs	$0.00476	$0.00276
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03037	$0.03015
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Regulatory Charges ($/kW)		
All Billed kWs	$4.12	$4.12

Lighting

Application:
Applies to any customer whose point of delivery is located within the limits of Austin Energy's service territory.

Character of Service:
Service provided under these rate schedules are pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

The rate tables below reflect rates with an effective date of October 1, 2016. For information on other applicable rates (i.e., power supply adjustment, community benefit, and regulatory), please see corresponding schedules in this tariff (if applicable). For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Discounts:
For any Independent School District, Military accounts as outlined in the Public Utility Regulatory Act §36.354, or State facilities the monthly customer-, delivery-, demand-, and energy-charges billed pursuant to these rate schedules will be discounted by 20 percent; all other electric charges will be billed pursuant to these rate schedules and will not be discounted.

GreenChoice® Energy Rider:
Service under these rate schedules is eligible for application of the GreenChoice® Energy (Rider).

Customer-Owned, Non-Metered Lighting

This rate applies to non-metered electric service to the Texas Department of Transportation for sign lighting and safety illumination at various locations.

	Summer (June through September)	**Non-Summer** (October through May)
Energy Charges ($/kWh)		
All Billed kWh	$0.02604	$0.02604
Power Supply Adjustment Charge ($/kWh)		
All Billed kWh	$0.03148	$0.03124

Customer-Owned, Metered Lighting

This rate applies to electric service to metered athletic field accounts whose connected load is more than 85 percent attributable to lighting, as verified by Austin Energy.

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges ($/month)		
Customer	$15.00	$15.00
Delivery	$0.00	$0.00
Energy Charges ($/kWh)		
All Billed kWh	$0.06175	$0.06175
Power Supply Adjustment Charge ($/kWh)		
All Billed kWh	$0.03148	$0.03124

City of Austin - Owned Outdoor Lighting

This rate applies to electric service to non-metered outdoor lighting owned and operated by the City of Austin other than Service Area Lighting.

	Summer (June through September)	**Non-Summer** (October through May)
Fixture Charges ($/fixture/month)		
100 Watt or Less (Billable 35 kWh)	$7.03	$7.03
101 - 175 Watt (Billable 60 kWh)	$12.05	$12.05
176 - 250 Watt (Billable 90 kWh)	$18.07	$18.07
251 Watt or Greater (Billable 140 kWh)	$28.12	$28.12
Power Supply Adjustment Charge ($/kWh)		
All Billed kWh	$0.03148	$0.03124

Service Area Lighting

This rate applies to electric service for illumination and the operation of traffic signals on all public streets, highways, expressways, or thoroughfares; other than non-metered lighting maintained by the Texas Department of Transportation. Revenues received through the Service Area Lighting component of the Community Benefit Charge are applied to offset these charges inside the City of Austin.

	Summer (June through September)	**Non-Summer** (October through May)
Energy Charges ($/kWh)		
All Billed kWh	$0.23219	$0.23219
Power Supply Adjustment Charge ($/kWh)		
All Billed kWh	$0.03148	$0.03124

Power Supply Adjustment

Application:
Applies to all electric service whose point of delivery is located within the limits of Austin Energy's service territory, unless otherwise stated.

Character of Service:
The Power Supply Adjustment (PSA) provides for the recovery of the preceding year's expenditures for Electric Reliability Council of Texas (ERCOT) settlements, fuel costs, net purchased power agreement costs, and any adjustment for the over- or under-recovery PSA balance. The PSA comprises the following costs (PSA Costs):

- ERCOT Settlements – charges and credits from ERCOT, other than the Administrative and Nodal Fees.
- Fuel Costs – costs for fuel, fuel transportation, and hedging gains and losses.
- Net Purchased Power Costs – costs and offsetting revenues associated with short- and long-term purchased power agreements, and costs for distributed generation production.

As part of the City of Austin's annual budgeting process, which includes a public hearing, the PSA is determined by calculating the sum of all net power supply costs plus any existing over- or under-recovery of PSA Costs balance that are attributable to the PSA divided by projected service area sales during the historical twelve month period preceding the effective date of the PSA. This results in an annual uniform system rate per kWh, that is adjusted for voltage level to be applied to each of the customer classes. The PSA is adjusted by the following voltage level factors:

Voltage Level	Adjustment Factor
Secondary	1.0049
Primary	0.9821
Transmission	0.9696

The PSA may be adjusted to eliminate any over- or under-recovery as described below. Within 30 days of any adjustment of the PSA to eliminate over- or under-recovery of costs, the City Manager will publicly present a report to the City Council that provides the underlying calculations for the PSA both pre- and post-adjustment by system voltage level.

If, at any time, the balance of PSA costs recovered since the date of the last PSA adjustment is more than 110 percent of PSA costs actually incurred during such period, and such over-recovery is projected to remain above 110 percent after 12 months from the date of the last PSA adjustment, the PSA shall be adjusted to eliminate the over-recovery balance within the next 12 months.

If, at any time, the balance of PSA costs recovered since the date of the last PSA adjustment is less than 90 percent of PSA costs actually incurred, and such under-recovery is projected to remain less than 90 percent after 12 months from the date of the last PSA adjustment, the PSA may be adjusted to eliminate the under-recovery balance within the next 12 months.

At least once each year, the City Manager will publicly present a report to the City Council that provides the underlying calculations for the PSA by customer class. These calculations will break out fuel costs, ERCOT charges and credits, including ancillary service sales, and purchased power costs and revenues, including bilateral sales. They will also show the extent of over- or under-recovery of PSA costs for the previous twelve months.

The PSA is seasonally adjusted to reflect Austin Energy's summer peaking nature, ERCOT market constraint and stresses during summer months. The seasonal PSA Cost percentage that is derived from a 3 year average of PSA Cost (two years of historical and one year of current costs).

PSA Cost Periods	Seasonal Adjustment Factor
Summer	40.26%
Non-Summer	59.74%
Total	100.00%

The seasonal PSA charges by voltage level are:

Voltage Level	Adjustment Factor	Summer Power Supply Rate ($/kWh)	Non-Summer Power Supply Rate ($/kWh)
System Average	1.0000	$0.03133	$0.03110
Secondary	1.0049	$0.03148	$0.03124
Primary	0.9821	$0.03076	$0.03053
Transmission	0.9696	$0.03037	$0.03015

Community Benefit Charge

Application:
Applies to all electric service whose point of delivery is located within the limits of Austin Energy's service territory, unless otherwise stated.

Character of Service:
The Community Benefit Charge recovers certain costs incurred by the utility as a benefit to Austin Energy's service area customers and the greater community. This charge shall be determined through the City budget process and applied by system voltage level. The charge include three specific programs and services provided to customers.

1. Service Area Lighting (SAL) recovers the cost of street lighting (other than lighting maintained by Texas Dept. of Transportation) and the operation of traffic signals located inside the city limits of Austin. Customers whose point of delivery is located outside the city limits of Austin are not subject to the Service Area Lighting component of the Community Benefit Charge.

2. Energy Efficiency Services (EES) recovers the cost of energy efficiency rebates and related costs, solar rebates, and the Green Building program offered by Austin Energy throughout its service area.

3. The Customer Assistance Program (CAP) funds projects that help qualifying low-income and other disadvantaged residential customers through bill discounts, payment assistance (Plus 1), and free weatherization services. Funding for CAP is provided through the CAP component of the Community Benefit Charge and unexpended and re-appropriated funds. Information regarding CAP shall be made available quarterly, including the number of residential customers enrolled automatically and through self-enrollment, the total and average amount of benefits provided, and the number of residential customers referred to the low-income weatherization program. With Council approval, funds unspent at the end of a fiscal year shall be rolled over to the next fiscal year's budget for the CAP program.

Effective Date October 1, 2016	**Service Area Lighting**	**Energy Efficiency Services**	**Customer Assistance Program**
Secondary Voltage (Residential) ($/kWh)			
Inside City Limits	$0.00145	$0.00246	$0.00172
Outside City Limits	$0.00000	$0.00246	$0.00118
Secondary Voltage (Non-Residential) ($/kWh)			
Inside City Limits	$0.00145	$0.00246	$0.00065
Outside City Limits	$0.00000	$0.00246	$0.00065
Primary Voltage ($/kWh)			
Inside City Limits	$0.00141	$0.00240	$0.00065
Outside City Limits	$0.00000	$0.00240	$0.00065
Transmission Voltage ($/kWh)			
Inside City Limits	$0.00140	$0.00237	$0.00065
Outside City Limits	$0.00000	$0.00237	$0.00065
Transmission and Primary Voltage ≥ 20 MW @ 85% aLF ($/kWh)			
Inside City Limits	$0.00000	$0.00000	$0.00065

Outside City Limits	\$0.00000	\$0.00000	\$0.00065

Regulatory Charges

Application:
Applies to all electric service whose point of delivery is located within the limits of Austin Energy's service territory, unless otherwise stated.

Character of Service:
The Regulatory Charge recovers the following costs, excluding any costs recovered through the closed Fuel Adjustment Clause: 1) ERCOT transmission service charges and credits; 2) NERC/TRE regulatory fees and penalties; 3) the ERCOT Nodal and Administrative Fees; and 4) other material regulatory fees or penalties specific to the electric industry. The Regulatory Charge is applied by system voltage level on either an energy or demand basis and may be adjusted to eliminate any over- or under-recovery on a system basis. Changes to the Regulatory Charge shall be determined after notice and public hearing as required by City code.

Voltage Level	**Regulatory (Energy)** ($/kWh)	**Regulatory (Demand)** ($/kW)
Secondary	$0.01159	$3.24
Primary	N/A	$3.16
HLF Primary	N/A	$3.91
Transmission	N/A	$3.12
HLF Transmission	N/A	$3.98

Standby Capacity

Application:
These rates apply to electric service for standby power provided by Austin Energy during a scheduled or unscheduled outage of customer's production facilities whose point of delivery is located within the limits of Austin Energy's service territory.

Character of Service:
Service is provided under this rate schedule pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes.

For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

The Standby Capacity will be equivalent to the maximum demand of the load to be served by Austin Energy during a scheduled or unscheduled outage of the customer's power production facilities or as stipulated in the contract between Austin Energy and the customer.

Customer will be assessed a monthly Minimum Bill equal to the Standby Capacity Rate times the Standby Capacity.

Voltage Level	**Monthly Standby Capacity Rate** ($/kW)
Primary	$2.80
Transmission	$2.60

Rider Rate Schedules

Application:
These rider rates apply to electric service whose point of delivery is located within the limits of Austin Energy's service territory.

Character of Service:
Service is provided under these rate schedules pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Non-Residential Distributed Generation from Renewable Sources (Rider)

Application:
This Rider is available to any non-residential customer who owns or hosts an on-site generating system powered by a renewable resource with a capacity of not more than 20 kW-ac that is interconnected with Austin Energy's electric system. Non-residential customers who own or host an on-site generating system powered by a renewable resource with a capacity of more than 20 kW-ac shall not be subject to this rider, and instead will be subject to the terms and conditions of the rate schedule under which the customer receives service, for all energy delivered by Austin Energy.

Renewable energy technologies include those that rely on energy derived directly from the sun, wind, geothermal, hydroelectric, wave, or tidal energy, or on biomass or biomass-based waste products, including landfill gas. A renewable energy technology does not rely on energy resources derived from fossil fuels, waste products from fossil fuels, or waste products from inorganic sources.

Terms and Conditions:
All charges, character of service, and terms and conditions of the rate schedule under which the customer receives service apply except as expressly altered by this rider. The customer shall comply with applicable Austin Energy interconnection requirements, including submittal of any required interconnection application and signed agreement. The customer is responsible for the costs of interconnecting with Austin Energy's electric system, including transformers, service lines, or other equipment determined necessary by Austin Energy for safe installation and operation of the customer's equipment. The customer is responsible for any costs associated with required inspections and permits.

Metering under this rider shall be by a single master meter capable of registering the flow of electricity in both directions to determine the customer's net energy flow. Other meters may be required to track renewable energy generation for regulatory compliance or incentive purposes, or as otherwise required by Austin Energy's Interconnection Guidelines and Design Criteria.

The customer's billed kilowatt-hour (kWh) shall be the customer's monthly net energy (kWh) use, which is the energy delivered by Austin Energy to the customer less any energy received from the customer's system to the Austin Energy distribution system during the billing month. If in any billing month the customer's monthly net energy use is negative, the customer's electric bill shall be credited as follows:

- If the Power Supply Adjustment applies, the monthly credit equals the monthly net energy times the Power Supply Adjustment (¢/kWh).

- If the GreenChoice® Energy (Rider) applies, the monthly credit equals the monthly net energy times the Power Supply Adjustment (¢/kWh).

Any charges not collected on a kWh basis are not altered by this calculation. Any credit shall be applied to the customer's bill for electric service. Any credit in excess of the customer's total charges for electric service, excluding the customer charge, shall be carried forward and applied to the customer's next electric bill.

GreenChoice® Energy (Rider)

Subscriptions under the GreenChoice® program support the City of Austin's inclusion of renewable fuel sources in its power generation portfolio. This energy cannot be directed to any one particular destination on the Electric Reliability Council of Texas electric grid, including participant's premises.

Application:
This rider applies to electric service to a customer subscribed to the City of Austin's GreenChoice® program.

Terms and Conditions:
Except for subscriptions of 1.2 million kilowatt-hours or more annually, subscriptions entered into after September 30, 2013, must be for 100 percent of a meter's monthly energy usage and will receive the adjustable GreenChoice® Charges. Non-residential customers may opt to enter into a written subscription contract for a one-year term after which the subscription will continue on a monthly basis. Customers not under contract may unsubscribe from the program at any time. A customer who unsubscribes may not re-subscribe until the following calendar year.

After September 30, 2014, a customer who subscribes a total annual amount of 1.2 million kilowatt-hours or more may receive the adjustable GreenChoice® Charges as provided below or may enter into a written subscription contract for a fixed GreenChoice® Charges until December 31, 2019. Each account subscribed to the program for the fixed charge must be subscribed for either: 1) 100 percent of the account's energy usage; or 2) a specified amount of energy usage of at least 100,000 kilowatt-hours per billing month.

Under subscriptions to Batches 5 or 6, the GreenChoice® Charges will be applied to 100 percent of the customer's energy usage, unless otherwise specified in a subscription contract in effect on September 30, 2013, through the Batch's end date. Batches 5 and 6 are closed to additional subscriptions. A non-residential account that has been subscribed to Batch 5 or 6 may not be re-subscribed under new terms before the subscription Batch's end date.

The terms of a subscription contract in effect on December 31, 2014, shall prevail in the event of a conflict with this rider. The director of Austin Energy shall develop the contract terms and conditions for subscriptions entered into after December 31, 2014.

Green Choice® Charges:
While subscribed to the GreenChoice® program, a customer will be billed Green Choice® Charge in lieu of the Power Supply Adjustment (PSA) that would otherwise apply to the customer's subscribed energy usage, unless otherwise noted in the appropriate rate schedule.

Subscription Type	**GreenChoice® Charges** ($/kWh)
Effective Dates before October 1, 2013	
Batch 5 (End Date December 31, 2022)	$0.055000
Batch 6.21 (End Date December 31, 2021)	$0.057000
Effective Date October 1, 2013	
Adjustable	PSA amount plus $0.01000
Fixed	$0.04900
Effective Date January 1, 2015	

Residential SmartCents	PSA amount plus $0.00750
Commercial BusinessCents	PSA amount plus $0.00750
Commercial Energizer	PSA amount plus $0.00750
Commercial Patron 14	$0.04900
Commercial Patron 15	$0.04400

Value-Of-Solar (Rider)

Application:
Applies to any Residential Service account that has an on-site solar photovoltaic system interconnected with Austin Energy's distribution system behind the master meter.

Terms and Conditions:
Billable kilowatt-hour shall be based on metered energy delivered by Austin Energy's electric system and the metered energy consumed from an on-site solar system; also known as, the total metered energy consumption during the billing month. All non-kWh-based charges under the Residential Service rate schedule shall remain unaffected by the application of this rider.

For each billing month the customer shall receive a non-refundable, non-transferable credit equal to the metered kilowatt-hour output of the customer's photovoltaic system multiplied by the current Value-of-Solar Rate plus any carry-over credit from the previous billing month. Credits are applicable to the customer's total charges for Residential Service in the customer's name on the same premise and account where the on-site solar photovoltaic system is interconnected. Any remaining amount of credit(s) shall be carried forward and applied to the customer's next electric service bill. In the event of service termination, any credit balance will be applied to the Power Supply Adjustment (PSA) to reduce net purchased power costs.

The Value-of-Solar Rate is a tariff rider that is set annually through the Austin Energy budget approval process. Effective January 1 of each calendar year, the rate calculation uses the Value-of-Solar assessment's monthly average of the prospective twelve-months and the shorter period of either: a) the prevailing assessments since October 1, 2012, or b) the previous 48 months.

Effective Dates	**Value-of-Solar Rates** ($/kWh)
October 1, 2012	$0.12800
January 1, 2014	$0.10700
January 1, 2015	$0.11300
January 1, 2016	$0.10900

Load Shifting Voltage Discount (Rider)

Application:
Applies to any non-residential customer who, at a minimum shifts 30 percent of the customer's normal annual monthly average on-peak billed demand using storage technologies (*e.g.,* thermal energy storage), whose point of delivery is located within the limits of Austin Energy's service territory. The normal on-peak billed demand is defined as the maximum-billed demand recorded prior to taking service on this discount rider rate schedule, and corresponding energy, during the last 12-month period, or as may be determined by Austin Energy.

Character of Service:
Service is provided under these rate schedules pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
The non-residential customer shall enter into a separate agreement with Austin Energy for this load shifting voltage discount rider rate schedule. The voltage discount rider rate schedule will be applied to the underlining rates within the standard rate schedules for which the customers load and voltage would qualify. Customer shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes.

The Billed kW used to determine the Electric Delivery, the Demand, and Regulatory Charges shall be based on the highest 15-minute metered demand recorded during the Load Shifting on-peak period and adjusted for power factor. The Energy Charge shall be based on all energy consumption during the Load Shifting on-peak period. All other Charges (*i.e.,* PSA, CBC, etc.) will be billed at the underlining rates schedules based on all consumption.

The load shifting on-peak period load shall be shifted, not eliminated, nor replaced by the use of alternative fuels. There is no load forgiveness for operations during on-peak periods. For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Load Shifting Periods

	Annual
On-Peak Hours	
3:30 P.M. – 6:30 P.M.	Everyday
Off-Peak Hours	
6:30 P.M. – 3:30 P.M.	Everyday

Service Area Program

Application:
This service area program rate schedule applies to electric service whose point of delivery is located within the limits of Austin Energy's service territory.

Character of Service:
Service is provided under this rate schedule pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

Electric Vehicle Public Charging

This rate schedule applies to electric service to a customer through a public electric vehicle charging station under the Electric Vehicle Public Charging.

Six-month Subscription	
Charging (unlimited)	$23.095
No Subscription	
Charging ($/hour)	$1.85

Residential Service Pilot Programs

Application:
These pilot programs' rate schedules apply to electric service for domestic purposes in each individual metered residence, apartment unit, mobile home, or other dwelling unit whose point of delivery is located within the limits of Austin Energy's service territory. The appropriate General Service schedules applies where a portion of the dwelling unit is used for either: a) conducting a business or other non-domestic purposes, unless such use qualifies as a home occupation pursuant to City Code Chapter 25-2-900; or b) for separately-metered uses at the same premises, including, but not limited to: water wells, gates, barns, garages, boat docks, pools, and lighting. These rates apply to secondary voltage less than 12,470 volts nominal line to line.

Each rate schedule will be limited to a participation of 100 individual meters on a first-come, first-served basis, unless stated otherwise on their applicable rate schedule. Austin Energy may administratively suspend availability of these pilot programs at any time or append full participation.

Character of Service:
Service is provided under these rate schedules pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required. In case of a conflict, the terms and conditions for each of the pilot programs as laid out in their appropriate rate schedules govern.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under these rate schedules shall remain unaffected by the application of a rider(s).

Pilot programs availability is contingent upon Austin Energy's operational feasibility, system configuration, availability of appropriate meters, and the customer's premise. Customers selecting these rate options are not eligible to participate in levelized billing. The rate tables below reflect rates with an effective date of October 1, 2016. For information on rates (*i.e.*, power supply adjustment, community benefit, and regulatory) prior to this effective date, please see corresponding schedules in this tariff (if applicable). For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Customers are advised to conduct their own independent research before making any decisions because of the availability of these temporary pilot programs. If a customer elects to participation in any of the programs, the customer also agrees to participate in Austin Energy's load research efforts by allowing the customer's data to be collected. Austin Energy's use of such load research data will be strictly limited to the provision of electric service. Austin Energy will not disclose, share, rent, lease, or sell such data to any third party or affiliate for any other purpose, without the customer's express written consent. Customers selecting this option are not eligible to participate in levelized billing.

Discounts:
Residential customers who receive, or who reside with a household member who receives, assistance from the Comprehensive Energy Assistance Program (CEAP), Travis County Hospital District Medical Assistance Program (MAP), Supplemental Security Income Program (SSI), Medicaid, Veterans Affairs

Supportive Housing (VASH), the Supplemental Nutritional Assistance Program (SNAP), the Children's Health Insurance Program (CHIP), or the Telephone Lifeline Program are eligible for a discount under the Customer Assistance Program (CAP). The priority for program funding is CEAP, MAP, SSI, Medicaid, VASH, and SNAP followed by CHIP and then Telephone Lifeline recipients. Eligible residential customers will be automatically enrolled in the discount program through a third-party matching process, with self-enrollment also available directly through Austin Energy.

Customers enrolled in the discount program are exempt from the monthly Customer Charge and the CAP component of the Community Benefit Charge and shall receive a 10 percent bill reduction on kilowatt-hour-based charges, unless stated otherwise on their applicable rate schedule. Customers in the discount program, as well as other low income and disadvantaged residential customers, may be eligible for bill payment assistance through Plus 1 and for free weatherization assistance.

Rider Schedules:
Services under these rate schedules are eligible for application of GreenChoice Energy (Rider) and Value-Of-Solar (Rider), unless stated otherwise on their applicable rate schedule. Application of GreenChoice® Energy (Rider) will be applied to all energy consumption in addition to applicable power and fuel charges.

Time-Of-Use Rates

In lieu of the Standard Rates under the Residential Service rate schedule, customers receiving service under this rate schedule may choose the following time-of-use charges to be applied for a term of no less than twelve (12) consecutive billing cycles, otherwise, an early termination fee of $250.00 will be applied; at Austin Energy's sole discretion the fee could be waived.

Fuel Periods:

Weekdays	
Off-Peak	10:00 P.M. – 7:00 A.M.
Mid-Peak	7:00 A.M. – 3:00 P.M., 6:00 P.M. – 10:00 P.M.
On-Peak	3:00 P.M. – 6:00 P.M.
Weekends	
Off-Peak	Entire Day

Time-Of-Use Charges

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges ($/month)		
Customer	$10.00	$10.00
Delivery	$0.00	$0.00
Fuel Charges ($/kWh)		
Weekdays		
Off-Peak	$0.02586	$0.02393

Mid-Peak	$0.03078	$0.03097
On-Peak	$0.11894	$0.03139
Weekends		
Off-Peak	$0.02586	$0.02393
Energy Charges ($/kWh)		
0 – 500 kWh	$0.03300	$0.03300
501 – 1,000 kWh	$0.05600	$0.05600
1,001 – 1,500 kWh	$0.07595	$0.07595
1,501 – 2,500 kWh	$0.09100	$0.09100
Over 2,500 kWh	$0.10595	$0.10595
Community Benefit Charges ($/kWh)		
Energy Efficiency Services	$0.00246	$0.00246
Customer Assistance Program		
Inside City Limits	$0.00172	$0.00172
Outside City Limits	$0.00118	$0.00118
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00145	$0.00145
Regulatory Charge ($/kWh)		
Regulatory	$0.01159	$0.01159

Prepayment Rates

In lieu of the Residential Standard Rates, the prepayment rate schedule is available on a voluntary basis to customers within Austin Energy service service territory who receive their electric service from Austin Energy but their water and wastewater service from a non-City of Austin provider. The prepayment pilot program is available for a term of no more than 9 consecutive billing cycles. Participation will be limited to 300 individual meters on a first-come, first-served basis. Participants in the program shall receive service pursuant to the terms set forth in this Prepayment Rates Schedule and City Code Chapter 15-9. In the event of a conflict between the Prepayment Rates Schedule and the City Code, the Prepayment Rate Schedule shall govern.

Terms and Conditions:
In order to enroll, the customer must establish a prepayment credit balance. Security deposits are not required. Deposits previously paid to Austin Energy shall be returned to the customer or may be applied to the prepayment balance at the customer's request. Outstanding balances must either be paid prior to enrollment or will be placed on a deferred payment plan with a fixed percentage of all future payments applied to the outstanding balance. Prepayment participants are not eligible for new payment arrangements or credit extensions.

Energy usage will be charged on a daily basis; Council approved customer charges, miscellaneous charges, taxes and fees will be prorated. Participants in the prepayment pilot program will receive a 'true-up' paper or electronic monthly bill. Account balances may be checked through the prepayment web portal 24 hours a day, 7 days a week.

Prepayment pilot customers will receive notifications and alerts about their account. Upon enrollment, the prepayment customer will determine by which method they will receive communications: text (which may incur phone carrier charges), email or phone call. The prepayment customer must select at least one Austin Energy-approved notification method. Austin Energy will not be responsible for any termination of service or other damages resulting from the account holder's failure to update alert settings and contact information.

The prepayment customer is responsible for maintaining a credit balance in order to maintain electric service. Austin Energy will notify program participants when the prepayment account balance is at or below a predetermined threshold. Austin Energy may disconnect a customer's utility service without notice if the account reaches a zero or negative balance. Prepayment pilot program customers will no longer receive a written notice of disconnection. Service will be reconnected upon receipt of payment for the outstanding balance plus a payment amount to be credited towards future energy use. There are no disconnections during weather moratoriums; however, customers are liable for the payment of energy usage which occurs during this time.

Prepayment customers will have access to existing Austin Energy payment options. It is the customer's responsibility to allow enough time for payment processing. Any charges incurred by Austin Energy as a result of insufficient fund checks/electronic fund transfers, returned credit card payments, and the like shall be applied immediately to the account balance and may result in the disconnection of service if the account balance becomes zero or negative. Austin Energy reserves the right to disconnect electric service immediately without prior notice for specific reasons per City Code Chapter 15-9, Article 7. Austin Energy will close any prepayment account that has a zero or negative balance for a period of thirty (30) days; any account disconnected for such reason must reestablish service pursuant to City Code Chapter 15-9.

Electric customers or members of the household who are dependent upon electrical devices for health-related reasons, including life-sustaining equipment, or have Lifeline status are ineligible to participate in the program. Customers who receive benefits from City of Austin Utilities' Customer Assistance Program are ineligible for this rate schedule. Value-Of-Solar (Rider) is not applicable to this rate schedule.

Prepayment Daily Charges

	Inside City Limits	**Outside City Limits**
Basic Charges ($/day)		
Customer	$0.33	$0.33
Delivery	$0.00	$0.00
Energy Charges ($/kWh/day)		
0 – 16 kWh	$0.03300	$0.03800
16 – 33 kWh	$0.05600	$0.05600
33 – 49 kWh	$0.07595	$0.07815
49 – 82 kWh	$0.09100	$0.07815
Over 82 kWh	$0.10595	$0.07815
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03148	$0.03148
Non-Summer Power Supply (Oct – May)	$0.03124	$0.03124
Community Benefit Charges ($/kWh)		

Customer Assistance Program	$0.00172	$0.00118
Service Area Lighting	$0.00145	$0.00000
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kWh)		
Regulatory	$0.01159	$0.01159

Plug-In Electric Vehicle Charging Rates

Application:
For a separate residential meter circuit (installed at the customer's expense) attached to an in-home electric vehicle level 1, or higher, charging station for charging a plug-in electric vehicle (PEV). Customers receiving service under this rate schedule may choose the following electric vehicle charges to be applied for a term of no less than 12 consecutive billing cycles. If the customer elects to terminate participation in the program, the customer must pay an early termination fee of $200.00. Austin Energy may, in its sole discretion, elect to waive this termination fee. This rate schedule includes unlimited customer access to public electric vehicle charging station under the Electric Vehicle Public Charging rate schedule.

Terms and Conditions:
These charges are in addition to any other services the premise might be receiving; customers served under this rate schedule will be provided separate primary meter billing amounts and PEV meter billing amounts in their electric bill(s). The customer's primary metered usage is billed according to the primary rate schedule selected by the customer. The customer's PEV usage is billed according to this residential PEV schedule. The PEV meter billed amount will be based upon data delivered to Austin Energy.

In-home electric vehicle charging must be during off-peak periods, otherwise, all energy consumption will be multiplied at on-peak Fuel Charges; this applies when energy consumption outside of off-peak periods is greater than 10 percent of total monthly energy consumption. A one-time enrollment payment of $150 will be applied.

Customers receiving PEV charging station service are not eligible for any discounts and the Value-Of-Solar (Rider) rate schedule (if the customer has Value-Of-Solar it would be attached to the residential primary meter account, not the PEV meter account), under this rate schedule. Application of GreenChoice® Energy (Rider) will be applied to all energy consumption from the PEV meter in addition to Fuel Charges.

Time Periods:

Weekdays	
Off-Peak	7:00 P.M. – 2:00 P.M.
On-Peak	2:00 P.M. – 7:00 P.M.
Weekends	
Off-Peak	Entire Day

PEV Charging Station Charges

	Summer	Non-Summer

	(June through September)	(October through May)
Basic Charges ($/month)		
Delivery		
Demand (< 10 kW)	$30.00	$30.00
Demand (≥ 10 kW)	$50.00	$50.00
Fuel Charges ($/kWh) – Only applies if greater than 10 percent of total monthly energy consumption is used outside of "Off-Peak" periods, then these charges are applied to all energy consumption at on-peak fuel charges.		
Weekdays		
Off-Peak	$0.00000	$0.00000
On-Peak	$0.40000	$0.14000
Weekends		
Off-Peak	$0.00000	$0.00000

Closed Rate Schedule

Application:
THIS RATE SCHEDULE IS CLOSED TO NEW CUSTOMERS. This rate schedule applies to electric service whose point of delivery is located within the limits of Austin Energy's service territory.

Character of Service:
Service is provided under this rate schedule pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

Large Service Contract (Closed)

Application:
These rates are only available to the State of Texas and apply to a large service contract (LSC) customer that executed a separate contract for this service on or after October 9, 2006, in form and substance acceptable to Austin Energy, but before May 24, 2012. The contract requires the customer to remain a full requirements customer of Austin Energy through May 31, 2017, on which date the customer's contract and the terms of this rate schedule shall terminate. If Austin Energy subsequently adopts a rate schedule that provides more favorable rates, terms, or conditions than provided by this rates schedule and which describes a customer class for which the customer's large service contract accounts qualify, then the customer may terminate its contract and receive service pursuant to such subsequent rate schedule. Austin Energy enters and executes the contract and assumes its obligation in its proprietary capacity as the owner and operator of a utility enterprise increasingly in competition with other power suppliers for the attraction and retention of industrial loads, and in order to induce customer to remain a customer of Austin Energy. This rate schedule shall be effective through May 31, 2017, for all contracts between Austin Energy and the State of Texas.

Terms and Conditions:
Services under this rate schedule are eligible for application of Time-Of-Use Rates and Thermal Energy Storage (Rider) attached to them.

The LSC rates begins on the first day of the customer's billing cycle following the date that a separate contract has been executed between Austin Energy and the State of Texas, and shall be in effect for a period of thirty-six (36) months thereafter.

Not earlier than the first day of the thirty-seventh month after the effective date and not later than the last day of the seventy-second month after the effective date, a most favored nations clause applies (which clause does not apply to a rate paid by a governmental entity of the State of Texas, that is mandated by Federal or State law, the Public Utility Commission, a judicial body, or a retail pilot program affecting a customer of Austin Energy). It is the intent of this provision that the most favored nations clause will not apply unless Austin Energy voluntarily charges a lower rate to another LSC customer (who receives power at 12,500 volts or higher and has a demand for power that meets or exceeds 3,000 kW for any two months within the previous twelve months). If Austin Energy is required by Federal or State law, the Public Utility Commission, or a judicial body to charge a lower rate to a customer or group of customers, then the most favored nations clause does not apply.

For the remainder of the term of the contract after the seventy-second month after the effective date, Austin Energy may keep customer loads on-system by exercising a continuing right of first refusal to match the best offer of any competing suppliers. Austin Energy shall have until the later of sixty (60) months from the effective date, or seventy-five (75) days from the date it receives proper notice from Customer to exercise its right of first refusal. All such alternative proposals may be disclosed to Austin Energy on a confidential trade secret basis to the extent permitted by law, and shall be supported by a sworn affidavit signed by a corporate officer of the customer involved.

For the remainder of the term of the contract after the seventy-second month after the effective date, provided that retail competition in the electric utility industry in Texas is allowed and is available in Austin, Texas, Austin Energy shall not be obligated to charge the customer the service contract rates. In the event that retail competition is not allowed in Texas, or is not available in Austin, Texas, the customer shall continue to take power from Austin Energy at the LSC rates and be subject to extended application of the most favorable nations clause, until the end of the term of the contract.

These service contract rate schedules do not obligate Austin Energy to match the best offer of any competing supplier. In addition, nothing herein shall obligate Austin Energy to match any portion of an offer or other consideration not directly related to the supply of electric energy (i.e. generation, transmission and distribution) to the customer's facilities in the Austin area. In other words, Austin Energy would be required to match the total delivered cost of electric energy to the customer.

Contracts entered into under the provisions of these service contract rate schedules shall protect the integrity and enforceability of the City's right of first refusal. After a customer commences to purchase electric generation from a competing supplier (and Austin Energy fails to exercise its right of first refusal or to match the offer of a competing supplier), provision of generation service by Austin Energy to that portion of customer's total load removed from Austin Energy Electric System shall thereafter be at the sole option of Austin Energy. However, Austin Energy shall have a continuing obligation to provide transmission and distribution services, including ancillary services if needed, pursuant to its tariffs and the Public Utility Commission's Substantive Rules or other applicable laws and regulations.

A customer may not submit bids or offers received from competing suppliers, and thereby cause or require Austin Energy to exercise its right of first refusal in accordance with the terms of this tariff, more than once every twelve months.

Nothing in these service contract rate schedules or a contract under these service contract rate schedules shall operate to prevent, prohibit, or delay Austin Energy from recovering "stranded" costs from the customer, to the extent authorized by law, including those described in the Public Utility Regulatory Act.

If, notwithstanding the foregoing paragraph, any subsequent legislation would in any way operate to prevent, prohibit or delay recovery of the full amount, otherwise authorized by law, of "stranded" costs through any surcharge or additional charge or any new or revised rate level or element solely because of the existence or contents of these service contract rate schedules or the contract then the contract rates specified in these service contract rate schedules for energy, demand and fuel shall be deemed to be changed by an amount designed to exactly equal the revenue Austin Energy would otherwise recover but for the existence or contents of these service contract rate schedules or contract. Any such change shall take effect on the same date that the surcharge, additional charge or new or revised rate level or element would otherwise go into effect. If necessary the change may take the form of a one-time charge, assessable prior to or after customer switches generation suppliers. To the extent possible, while still allowing full recovery of the otherwise authorized amount, the change shall be incorporated into prospective monthly recurring charges.

The contract to be signed by customer shall explicitly incorporate the terms of the preceding two paragraphs, and also provide that the results contemplated by such paragraphs are essential and non-severable terms of the contract.

Notwithstanding any provision of these special contract rate schedules, neither customer nor Austin Energy shall be precluded from challenging the legal validity of any statute, regulations, or other provisions of law.

This rate schedule shall be extended to all of an LSC customer’s accounts having a maximum demand of at least 500 kW.

Upon request, customers receiving service under these service contract rate schedules will be provided dual feed service with reserve capacity and maintenance under the 10 year long contract provisions of the Service Contract Rider, except that the customer will be responsible for the initial assessment fee, customer requested changes to the initial assessment, and facilities design and construction costs, as established in the fee schedule. Dual feed service with reserve capacity is electric service provided to the customer’s premise(s) through two (or more) independent distribution feeders, with one feeder in normal service and the other in back-up service, capacity is reserved for the second feeder, and is placed into service upon an outage of the primary feeder.

If it is determined at any time by Austin Energy that the customer violated the provisions of these special contract rate schedules or the contract implementing this tariff, then the customer will be immediately billed on the LSC rate schedule, or as amended, from the date service was first commenced under these special contract rate schedules. The difference, plus interest at one percent (1%) per month, or the maximum allowable legal interest rate, whichever is less, from the date service was first commenced under these special contract rate schedules, shall immediately become due by customer to Austin Energy.

The contract executed under these special contract rate schedules shall address the rights of the City and the customer relating to the transfer or assignment of rights under these special contract rate schedules.

Definitions:

- Full Requirement Service – means generation, transmission, and distribution, (i.e., “bundled”) service as presently supplied by City of Austin to customer, provided however, that the customer may self-generate up to 500 kW of its requirements from customer-owned, on-site renewable energy technology, subject to the terms and conditions of Austin Energy’s Non-Residential Distributed Generation from Renewable Sources (Rider).

- Best Offer – means the cost of generation of a competing supplier, plus other costs, fees or expenses that a customer incurs in order to bring the generation to its point of service, including but not limited to: 1) transmission wheeling costs to Austin Energy Electric System; 2) transmission and distribution wheeling costs to the customer’s point of service; and 3) costs to install or construct any on-site generation, interconnection or metering facilities.

- Competing Suppliers – includes, but is not limited to, a provider of generation services, energy services, and ancillary services, whether or not the supplier is located inside Austin Energy's current service territory, to the extent that the provider is permitted by law to serve the customer load.

- Billing Demand – the kilowatt demand during the fifteen-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by Austin Energy. When customer's power factor during the interval of greatest use is less than 85 percent, Billing Demand shall be determined by multiplying the indicated demand by 85 percent and dividing by the lower peak power factor; provided, however, the power factor adjustment specified in this paragraph shall be superseded by any subsequent rate schedule or ordinance governing power factor that may be enacted or amended by Austin Energy from time to time.

- Power Supply Adjustment (PSA) – plus an adjustment for variable costs, calculated according to the Power Supply Adjustment rate schedule, multiplied by the billable kWh.

Time-Of-Use Periods

	On-Peak Hours	**Off-Peak Hours**
Summer (May through October)		
Monday – Friday	*1:00 P.M. – 9:00 P.M.*	*9:00 P.M. – 1:00 P.M.*
Saturday, Sunday, and Holidays[1]	*None*	*12:00 A.M. – 12:00 A.M.*
Non-Summer (November through April)		
Monday – Friday	*800 A.M. – 10:00 P.M.*	*10:00 P.M. – 8:00 A.M.*
Saturday, Sunday, and Holidays[1]	*None*	*12:00 A.M. – 12:00 A.M.*

Monthly Charges:
Customer will be assessed a monthly minimum bill of $12.00, if the below calculation result in a charge of less than $12.00.

Standard Rates

	Summer (May through October)	**Non-Summer** (November through April)
Demand Charges ($/kW)		
All kWs	$12.54	$11.40
Energy Charges ($/kWh)		
All kWhs	$0.01110	$0.01110
Power Supply Adjustment ($/kWh)		
All kWhs	$0.03076	$0.03053

Time-Of-Use Rates

At the option of the customer, a separate agreement may be entered into between the City and the customer for a time-of-use incentive rate.

[1] U.S. National Holidays are Memorial Day, Independence Day, and Labor Day.

Billed demand will be based on the fifteen-minute interval of greatest use during an on-peak period for the current billing month. All other adjustments will be included as described above (See Definition: Billing Demand).

	Summer (May through October)	**Non-Summer** (November through April)
Demand Charges ($/kW)		
All kWs	$12.54	$11.40
Energy Charges ($/kWh)		
Off-Peak	$0.00560	($0.00290)
On-Peak	$0.02410	$0.01710
Power Supply Adjustment ($/kWh)		
All kWhs	$0.03076	$0.03053

Thermal Energy Storage (Rider)

Application:
This rate is applicable to any LSC customer who, through the use of Thermal Energy Storage technology, shifts to off-peak time periods no less than the lesser of 20 percent of the customer's normal on-peak Summer Billed Demand or 2,500 kW. The normal on-peak Summer Billed Demand shall be the maximum Summer Billed Demand recorded prior to attaching this rider, or as determined by Austin Energy.

Terms and Conditions:
At the option of the customer, a separate agreement may be entered into between the City and the customer for a Thermal Energy Storage (Rider) incentive rate. The on-peak load shall be shifted to off-peak, not eliminated, nor replaced by the use of alternative fuels. The customer shall continue to be billed under the time-of-use rates and in accordance with the following provisions:

- For Summer (May through October), the Summer Billed Demand shall be the highest fifteen-minute demand recorded during the on-peak period.
- For Non-Summer (November through April), the Non-Summer Billed Demand shall be the highest fifteen-minute demand recorded during the month, or 90 percent of the Summer Billed Demand set in the previous summer; whichever is less.

Time-Of-Use Periods

	Summer (May through October)	**Non-Summer** (November through April)
On-Peak Hours		
4:00 P.M. – 8:00 P.M.	Monday – Friday	None
Off-Peak Hours		
8:00 P.M. – 4:00 P.M.	Monday – Friday	Everyday
12:00 A.M. – 12:00 A.M.	Saturday, Sunday, and Holidays[2]	Everyday

[2] U.S. National Holidays are Memorial Day, Independence Day, and Labor Day.

Glossary of Terms

The purpose of this section is for customers to have a better understanding of the terminology used within the electric industry.

Adjustment Clauses

A provision in Austin Energy's tariff that provides for periodic changes in charges or credits to a customer due to increases or decreases in certain costs over or under those included in base rates.

Base Rate

That portion of the total electric rate covering the general costs of doing business, except for fuel, purchased power, and other pass-thru expenses.

Billed Demand

The demand upon which billing to a customer is based, as specified in a rate schedule or contract, metered X demand or billed demand may be the metered demand adjusted for power factor as specified in the rate schedule. It may also be based on the contract year, a contract minimum, or a previous maximum that does not necessarily coincide with the actual measured demand of the billing period.

Customer

A meter, individual, firm, organization, or other electric utility that purchases electric service at one location under one rate classification, contract, or schedule. If service is supplied to a customer at more than one location, each location shall be counted as a separate customer unless the consumptions are combined before the bill is calculated.

Customer Charge

Customer Charge is a monthly charge to help Austin Energy recover the customer-related fixed costs that reflect the minimum amount of equipment and services needed for customers to access the electric grid. Such costs are billing, metering, collections, customer service, service drops, cost of meters, meter maintenance, and other customer-related costs; these costs vary with the addition or subtraction of customers. These costs do not vary with usage; therefore, it is appropriate to recover these costs in the Customer Charge, rather than Energy Charges.

Customer Class

The grouping of customers into homogeneous classes. Typically, electric utility customers are classified on a broad category of customer service: residential, general service (commercial), large general service (industrial), lighting, or contract. Some electric systems have individual customers (large users) with unique electric-use characteristics, service requirements, or other factors that set them apart from other general customer classes and thus may require a separate class designation.

Delivery (Distribution) Charges

The charges on an electric customer's bill for the service of delivering or moving of electricity over the distribution system from the source of generation to the customer's premise; sometimes referred to as Electric Delivery.

Demand Charges

That portion of the charge for electric service based upon the electric capacity (kW or kVa) consumed and billed based on billing demand under an applicable rate schedule. The cost of providing electrical transmission and distribution equipment to accommodate the customer's largest electrical load during a given period of time.

Demand (kW)

The rate at which electricity is being used at any one given time. Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time. Demand is often measured in Kilowatts, while energy use is usually measured in Kilowatt-hours. The term "load" is considered synonymous with "demand."

Electric Meter

A device that measures the amount of electricity a customer uses.

Electric Rate

The price set for a specified amount of electricity in an electric rate schedule or sales contract.

Electric Reliability Council of Texas (ERCOT)

An independent system operator that schedules power for the region, which represents about 90 percent of the State of Texas's electric load.

Energy Charges

That portion of the charge for electric service based upon the electric energy consumed or billed. Electrical energy is usually measured in kilowatt-hours (kWh), while heat energy is usually measured in British thermal units (Btu).

Energy Efficiency Programs

Programs sponsored by utilities or others specifically designed to achieve energy efficiency improvements. Energy efficiency improvements reduce the energy used by specific end- use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Energy Efficiency Service Charge

Charge assessed to customers to offset the cost of energy efficiency program services offered by Austin Energy.

Fuel Adjustment (PSA)

A rate schedule that provides for an adjustment to the customer's bill for the cost of power supply.

Green Pricing (GreenChoice)

An optional Austin Energy service that allows customers an opportunity to support a greater level of Austin Energy's investment in and/or purchase of power from renewable energy technologies. Participating customers pay a premium on their electric bill to cover the incremental cost of the additional renewable energy.

Inverted Rate Design

A rate design for a customer class for which the unit charge for electricity increases as usage increases.

Kilowatt-hour (kWh)

The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatt-hour equals 1,000 watt-hours. The number of kWhs is used to determine the energy charges on your bill.

Load Factor

The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. Load factor, in percent, is derived by multiplying the kilowatt-hours in the period by 100 and dividing by the product of the maximum demand in kilowatts and the number of hours in the period.

Load Profile

Shows the quantity of energy used by a class of customers at specific time intervals over a 24-hour period.

Load Shifting

Involves shifting load from on-peak to mid- or off-peak periods. Popular applications include use of storage water heating, storage space heating, cool storage, and customer load shifts to take advantage of time-of-use or other special rates.

Megawatt (MW)

One megawatt equals one million watts or 1,000 kWhs.

Megawatt-hour (MWh)

One megawatt-hour equals one million watt-hours or 1,000 kWs.

Minimum Bill

A minimum charge to a customer during the applicable period of time, which is typically the customer charge. A provision in a rate schedule stating that a customer's bill cannot fall below a specified level. A minimum charge is similar to a customer charge because it is designed to recover fixed costs of services such as meter reading, billing and facilities maintenance. Although this charge does not generally recover the full cost of these services, it does give the customer a price signal that these costs do exist.

Off-Peak

Period of time when the need or demand for electricity on AE's system is low, such as late evenings, nights, weekends, and holidays.

On-Peak

Period of time when the need or demand for electricity on AE's system is high, normally during the late afternoons and early evening hours of the day from Monday through Friday, excluding holidays.

Peak Load Pricing

Pricing of electric service that reflects different prices for system peak periods or for hours of the day during which loads are normally high.

Peak Season Pricing

Pricing of electric service that reflects different prices for system peak seasonal periods.

Power Factor

The ratio of real power (kW) to apparent power (kVA) at any given point and time in an electrical circuit. Generally, it is expressed as a percentage ratio.

Power Factor Adjustment

A clause in a rate schedule that provides for an adjustment in the billing if the customer's power factor varies from a specified percentage or range of percentages.

Primary Voltage

The voltage of the circuit supplying power to a transformer is called the primary voltage, as opposed to the output voltage or load-supply voltage, which is called secondary voltage. In power supply practice the primary is almost always the high-voltage side and the secondary the low-voltage side of a transformer, except at generating stations.

Public Street and Highway Lighting

Electricity supplied and services rendered for the purpose of lighting streets, highways, parks, and for other public places; or for traffic or other signal system service for municipalities, or for other divisions or agencies of State or Federal governments.

Rate Schedule

A statement of the rates, charges, and terms and conditions governing the provision of electric service that has been accepted by a regulatory body with established oversight authority.

Rate Structure

The design and organization of billing charges to customers. A rate structure can comprise one or more of the rate schedules defined herein.

Seasonal Rates

Rate schedules that are structured for the different seasons of the year. The electric rate schedule usually takes into account demand based on weather and other factors.

Secondary Voltage

The output voltage or load-supply voltage of a transformer or substation. In power supply practice secondary voltage is generally the low-voltage side of a transformer, except at generating stations.

Single-Phase Service

Service where facility (e.g., house, office, warehouse) has two energized wires coming into it. Typically serves smaller needs of 120V/240V. Requires less and simpler equipment and infrastructure to support and tends to be less expensive to install and maintain.

Special Contract Rate Schedule

An electric rate schedule for an electric service agreement between Austin Energy and another party in addition to, or independent of, any standard rate schedule.

Standby Service

Service that is not normally used but that is available through a permanent connection in lieu of, or as a supplement to, the usual source of supply.

Tariff

A published collection of rate schedules, charges, terms of service, rules and conditions under which the Austin Energy provides electric service to the public.

Thermal Energy Storage

Is a technology that stocks thermal energy by heating or cooling a storage medium so that the stored energy can be used at a later time for heating and cooling applications and power generation.

Three-Phase Service

Electric energy that is transmitted by three or four wires to the customer. Relatively high voltage customers usually receive three-phase power.

Time-of-Use (Time-of-Day) Rates

A rate structure that prices electricity at different rates, reflecting the changes in the AE's costs of providing electricity at different times of the day. With time-of-use rates, higher prices are charged during the time when the electric system experiences its peak demand and marginal (incremental) costs are highest. Time-of-use rates better reflect the cost of providing service, sending more accurate price indicators to customers than non-time-of-use rates. Ultimately, these rates encourage efficient consumption, conservation and shifting of load to times of lower system demand.

Value of Service

A utility pricing concept in which the usefulness or necessity of a service to a customer group replaces or supplements cost factors as a major influence on the rates charged to the group. In ratemaking, this means that the price charged reflects the service's value to the customer rather than its cost to the producer. Value of service need not equal the cost of service; for example, Austin Energy's Value-of-Solar is such a product.

Volt

The unit of electromotive force or electric pressure analogous to water pressure in pounds per square inch. It is the electromotive force that, if steadily applied to a circuit having a resistance of one ohm, will produce a current of one ampere.

Watt

The electrical unit of real power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing due to an electrical pressure of one volt at unity power factor. One watt is equivalent to approximately 1/746 horsepower, or one joule per second.

FINAL REPORT | December 28, 2015

SECONDARY VOLTAGE CUSTOMER CLASSES

Austin Energy

Austin, Texas

PREPARED BY:

NewGen Strategies & Solutions

ECONOMICS STRATEGY STAKEHOLDERS SUSTAINABILITY

www.newgenstrategies.net

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Section 1
INTRODUCTION

NewGen Strategies and Solutions, LLC (NewGen) was tasked by Austin Energy (AE) to review the delineation of the secondary voltage classes. For this analysis, NewGen was asked to disregard current class groupings and to provide a proposal for class delineations based on differences in customer usage characteristics that would result in cost of service differentials. In order to make this determination, NewGen examined customer hourly usage data from approximately 900 samples of secondary voltage customers ranging in size from nearly 0 kilowatt (kW) demand to over 3,000 kW demand. Load profiles were analyzed to understand how differences in customer usage characteristics would impact the allocation of costs to the various secondary service customer classes. Important usage characteristics that influence cost of service results include contribution to both AE and Electric Reliability Council of Texas (ERCOT) summer coincident peaks (4CP), contribution to AE monthly system peaks (12CP), load diversity and contribution to class non-coincident peak (NCP), load factor, and cost to serve AE's load in the ERCOT market. NewGen also interviewed system planners and reviewed design specifications to determine cost of service influences for various sizes of customers. These factors were analyzed to determine if there were unique load characteristics that influenced the cost to serve customers and warranted the development of unique rate classes based on customer size (as determined by demand measured in kW).

Section 2
LOAD PROFILE DATA

AE's cost of service methodology allocates costs to each customer class based on class demand, energy, and customer characteristics. Allocation of customer costs and energy costs are relatively straightforward and are based on class customer counts and energy usage. However, the allocation of demand costs are based on several measures of class contribution to demand. For AE, power supply demand-related costs are allocated to each customer class using the Average and Excess Demand/4CP (4CP) method. This method is very similar to using class contribution to the four highest monthly peaks of the year on the AE system (or the four coincident peaks). The 4CP allocation approach is also used to assign AE's demand-related transmission costs to the various retail classes, although, for the transmission costs, the coincidence is measured against the ERCOT peak, rather than the AE system peak. Distribution demand related costs are allocated to the various customer classes based on class peak demand for each month of the year (12NCP) and the sum of customer peak demands (Sum of Maximum Demands or SMD). To evaluate potential class delineations, NewGen reviewed customer load profiles and coincidence factors by various strata of maximum customer demands with the goal of finding groupings with similar cost of service impacts.

Coincidence factors are the ratio of a demand measurement at a specific time (such as at a class or system peak) to the maximum demand at any other time. For example, if a customer's average demand at the time of the four monthly summer system peaks is 5 kW and their maximum demand during any other period is 10 kW, then their 4CP coincidence is 50 percent. This relationship is important in rate making as demand costs may be allocated to customer classes based on factors such as the 4CP, but these costs are generally recovered through billed monthly maximum demand. Using the above example, a customer with a coincidence factor of 50 percent to the 4CP should have a demand charge (in $/kW) that is 50 percent of the system rate (calculated based on the 4CP) as their billed demand is, on average, twice as high as their demand during the 4CP. Thus, coincidence factors provide an appropriate link between how costs are allocated to customers and how they are billed to customers.

4CP

The first set of data reviewed by NewGen was the average coincidence to the summer 4CP period by customer size. This allocation factor is used to allocate the majority of demand-related production costs and is a near approximation to the ERCOT 4CP, which is used to allocate the majority of transmission costs. To review this dataset, NewGen plotted the average coincidence of the 4CP by customer demand. This analysis shows that there is 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. The average coincidence factor from 10 kW to 300 kW is 69 percent. After 300 kW, there is another increase in coincidence to an average of 84 percent for all customers above 300 kW. These findings are illustrated in Figures 2-1 and 2-2.

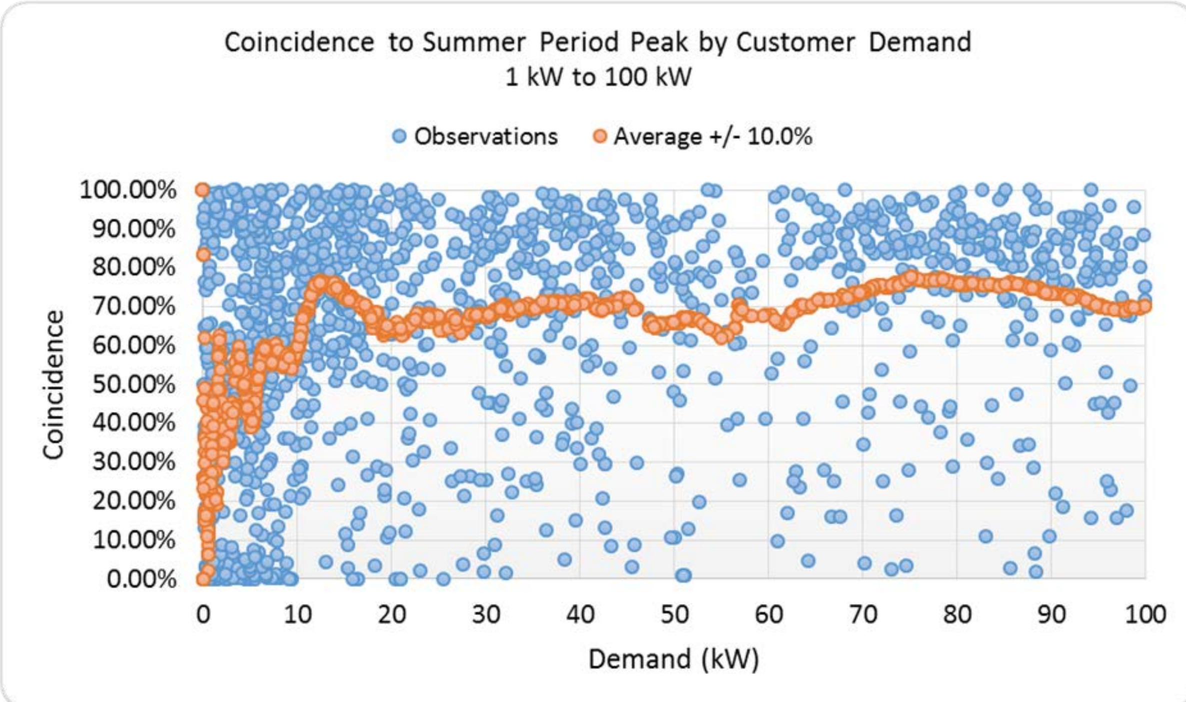


Figure 2-1. Coincidence to Summer Period Peak by Customer Demand (1 kW to 100 kW)

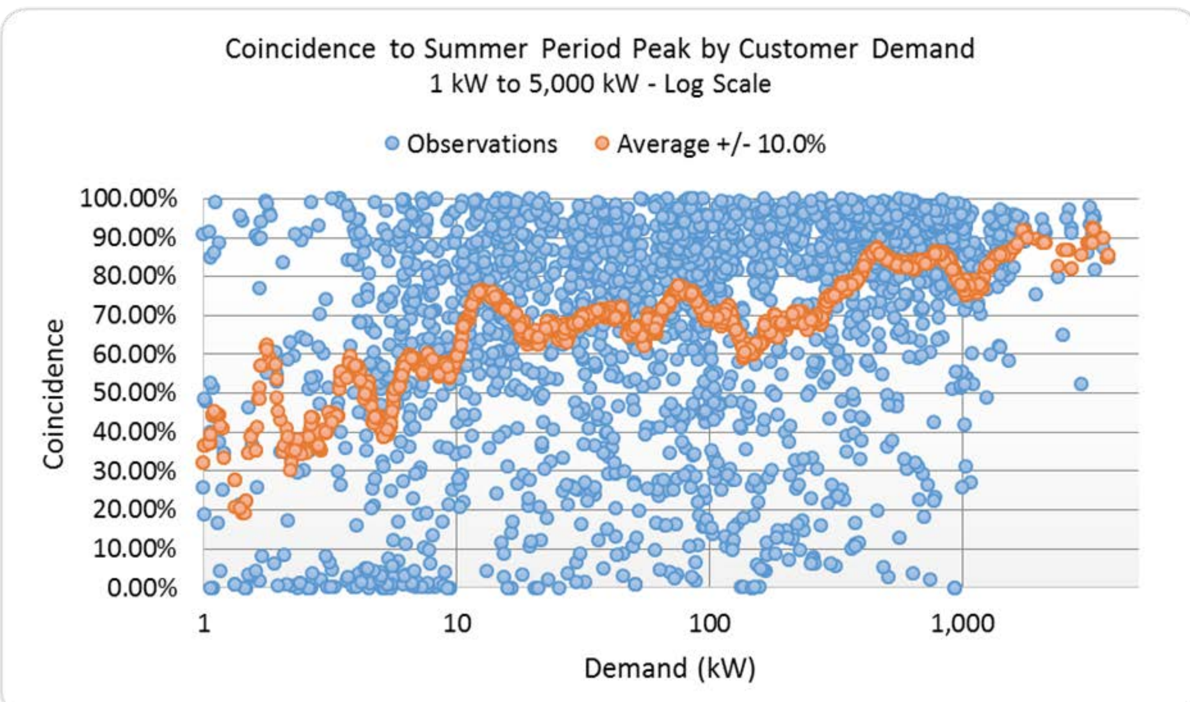


Figure 2-2. Coincidence to Summer Period Peak by Customer Demand (1 kW to 5,000 kW – Log Scale)

Analysis of coincidence to system peaks in the load research data identified three main groups of customers – 0 kW to 10 kW, 10 kW to 300 kW, and over 300 kW. This is illustrated in Figure 2-3, which demonstrates no meaningful differential in coincidence between groups of customers that are 10 kW to

50 kW as compared with customers that are 50 kW to 300 kW. It is worth noting that the customers around 3,000 kW exhibit coincidence of approximately 90 percent, but there are very few customers of this size.

An analysis of coincidence to the five peak hours for each summer month, as opposed to the single monthly peak, was performed to ensure that the near peak hours' coincidence did not significantly vary from the single hour peak. The results of this analysis verify that coincidence to near peak hours does not vary significantly from coincidence to the single hour peak as is shown in Figure 2-3.

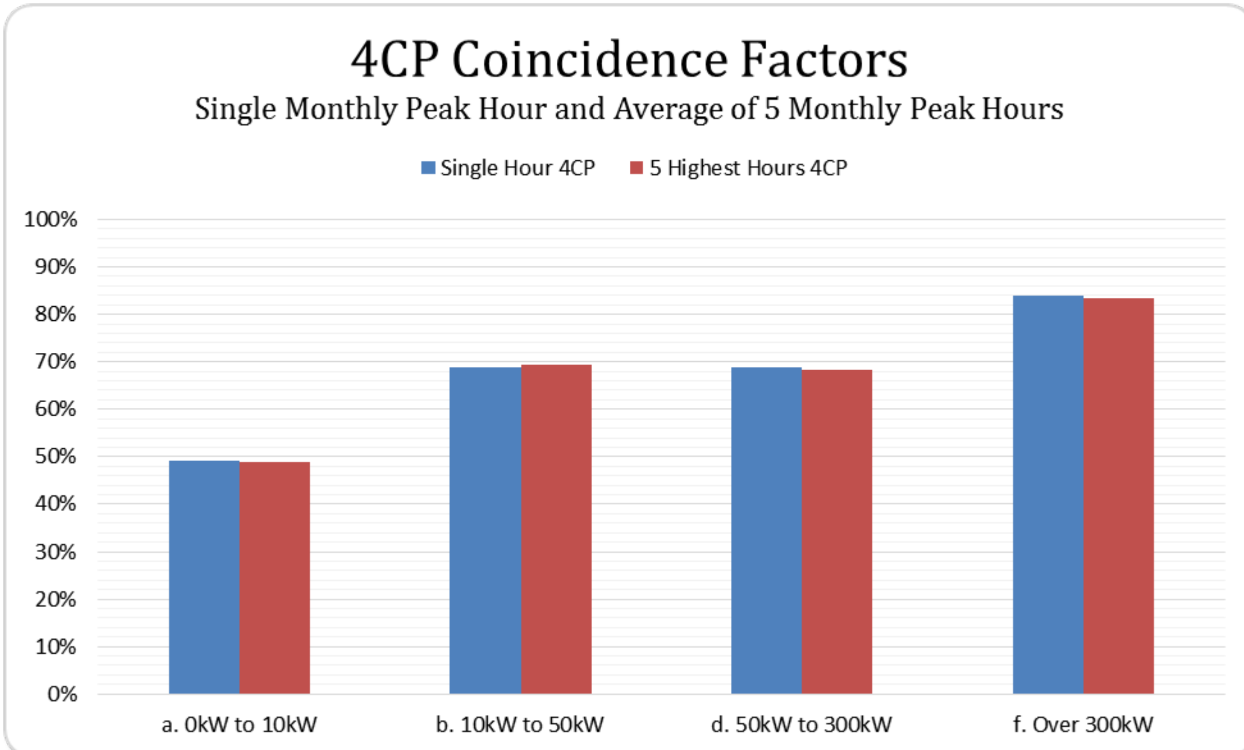


Figure 2-3. Coincidence to Summer Period Peak by Customer Demand (1 kW to 5,000 kW – Log Scale)

Average Versus Incremental Results

4CP results, as shown in the above figures, are based on an incremental evaluation of customer groups so that we can observe changing customer characteristics over a range of peak customer demands. Incremental results can be muted or averaged by combining groups of customers together. When measuring coincidence factors, if the coincidence of the larger blended group is similar to the separate incremental groups, then blending is justified. However, if the coincidence of the blended group is materially higher or lower than each of the incremental groups, then one incremental group of customers supports more or less of the cost compared to the other incremental groups. This is demonstrated in Figure 2-4.

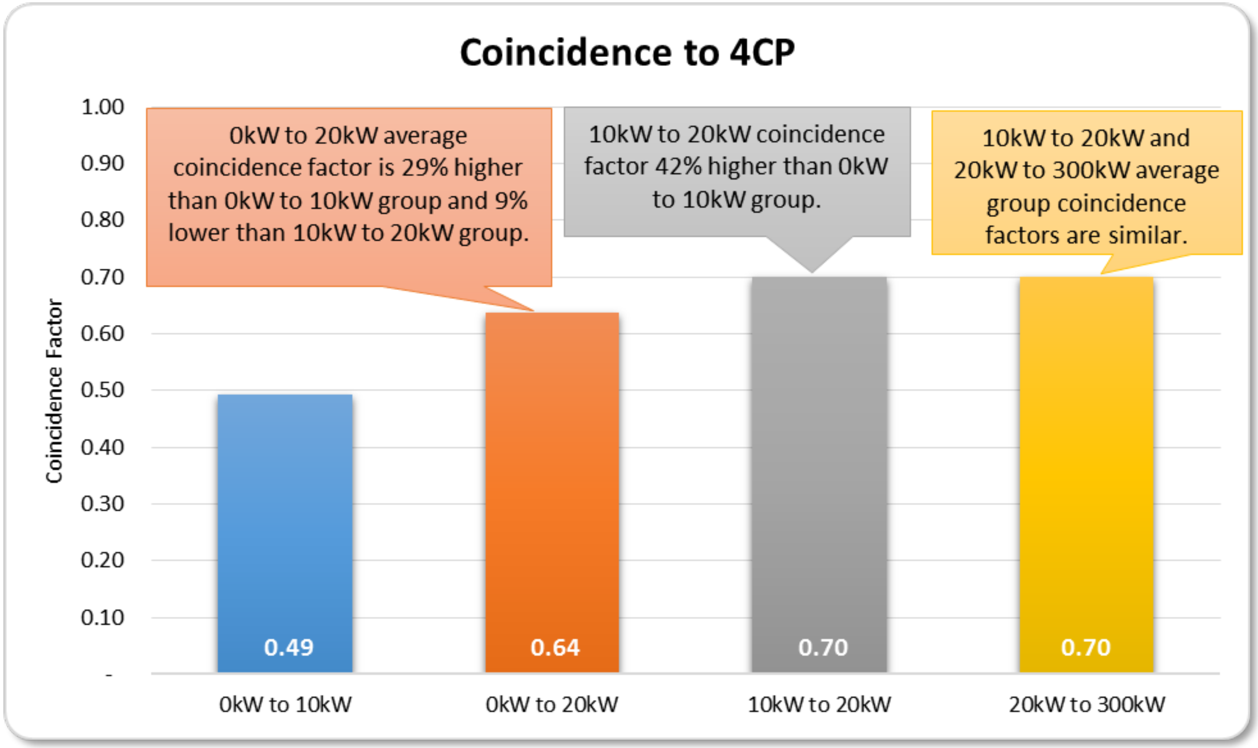


Figure 2-4. Coincidence to 4CP

As shown in Figure 2-4, customers with demands ranging from 0 kW to 10 kW would have to support a greater share of costs if they are grouped with customers with demands ranging from 10 kW to 20 kW. This occurs because the class average coincidence factor of customers with demands ranging from 0 kW to 20 kW is 29 percent higher than the class average coincidence factor of customers with demands ranging from 0 kW to 10 kW, if this group remained separated. As a result, the customers with demands ranging from 0 kW to 10 kW would incur more peak demand related costs if they are grouped into a larger 0 kW to 20 kW class. In addition, analysis of coincidence factors shows that the 10 kW to 20 kW group is similar to the 20 kW to 300 kW group and this analysis supports the combination of the 10 kW to 20 kW group with the 20 kW to 300 kW group to form a class of customers with demands from 10 kW to 300 kW.

Conclusion

Based on the information analyzed, we conclude the following:

- An incremental analysis of customer contribution to the system peak indicates that a material change in class coincidence factor occurs at 10 kW with customers in the group 10 kW to 20 kW having (on average) coincidence factors 42 percent higher than customers in the 0 kW to 10 kW group.
- An incremental analysis of customer contribution to the system peak indicates that a material change in class coincidence factor occurs at 300 kW with customers having demands between 10 kW and 300 kW (on average) having class coincidence factors that are 18 percent lower than customers with demands greater than 300 kW.

- Customer classes with higher coincidence factors will be allocated, on a per customer basis, a greater percentage of peak demand costs. This usually results in higher demand charges as compared to classes with lower coincidence factors.

12NCP

The 12NCP factor is used to allocate AE's distribution system costs. This factor measures diversity within a class compared to the class peak. NewGen's analysis of coincidence to the 12NCP by customer size closely mirrored coincidence to the 4CP. This perspective confirms common patterns for groups of customers in the ranges 0 kW to 10 kW, 10 kW to 300 kW, and above 300 kW. This is illustrated in Figure 2-5.

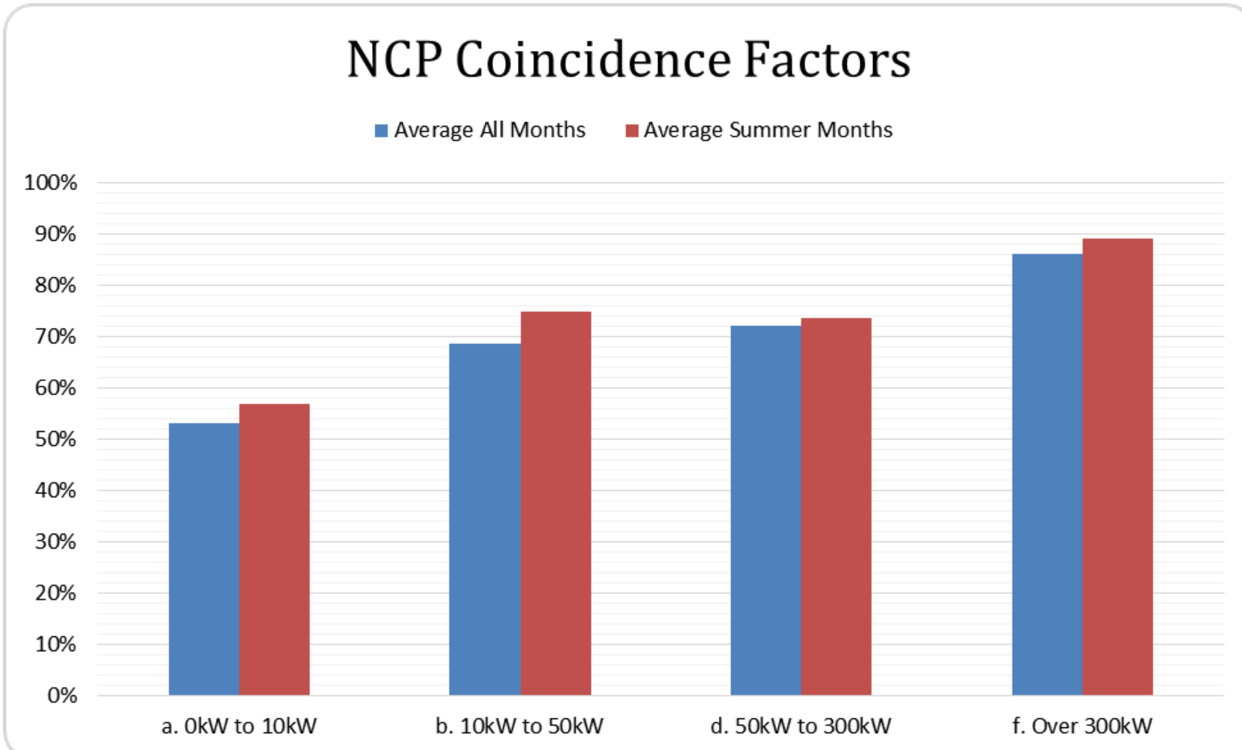


Figure 2-5. NCP Coincidence Factors

Conclusion

Based on the information analyzed, we conclude the following:

- An incremental analysis of customer contribution to the class peak confirms class designations as determined in the coincident peak analysis.

Class Load Factor

Class load factor is a measure of efficiency, with higher load factor classes having a lower average cost of service than lower load factor classes. Similar to class coincidence and non-coincidence factors, load factor was analyzed by customer group. This analysis shows that average load factor is fairly consistent on an average customer basis from 0 kW to 50 kW and then shows significant increases after 50 kW. This result is summarized in Figure 2-6.

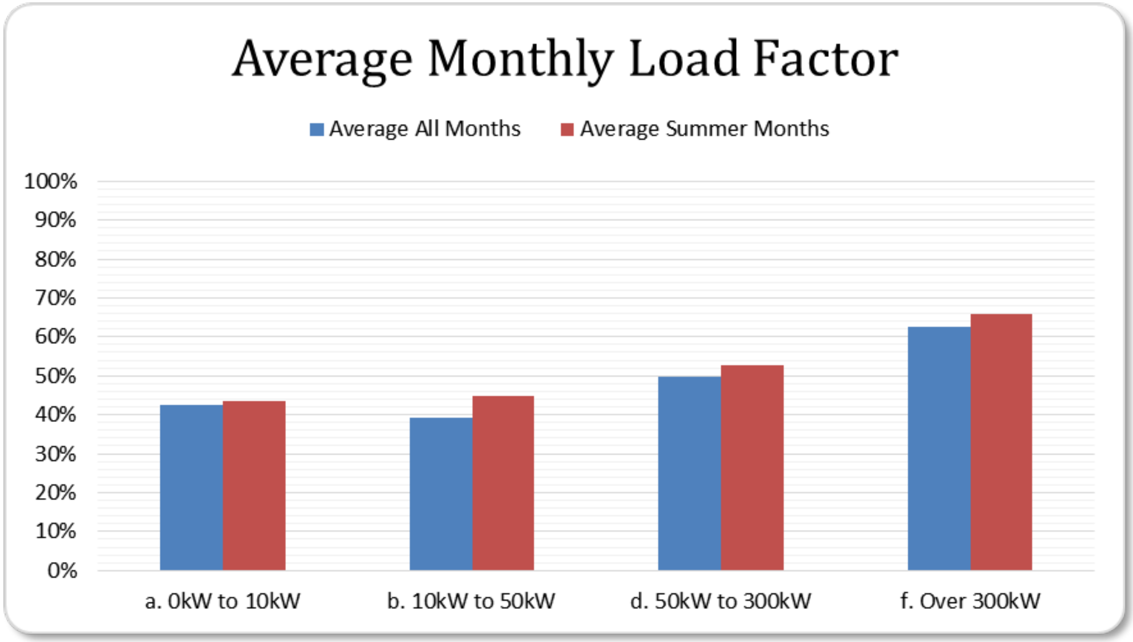


Figure 2-6. Average Monthly Load Factor

A properly designed rate structure containing both demand and energy components will reflect the costs of different load factors within a class and charge individual customers accordingly. As mentioned above, classes with higher coincidence factors will generally have higher demand charges as compared to other classes. Therefore, low load factor customers in a high coincidence class will pay a higher average rate than low load factor customers in a lower coincidence class. Without a demand charge, most costs are recovered via an average energy rate. The average energy rate reflects a blend of demand, energy, and customer related costs. So, load factor alone cannot be examined without consideration of class coincidence. For example, the load data indicates that customers with demands between 10 kW and 50 kW have a higher coincidence factor than customers with demands between 0 kW and 10 kW, yet, as shown in Figure 2-6, average load factors for these groups are similar. Therefore, given the same load factor, either for a customer or on a class average basis, the cost of service associated with the higher coincidence customer or class is greater. This is shown in the hypothetical cost curves in Figure 2-7.

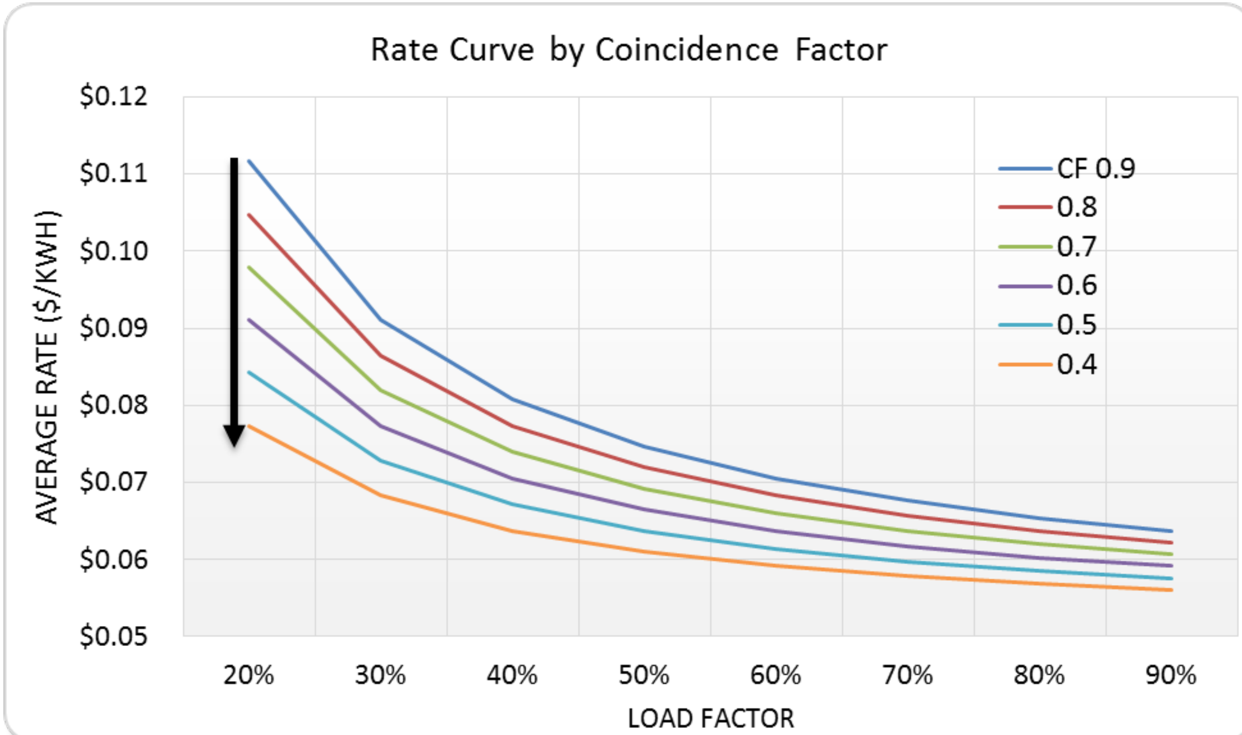


Figure 2-7. Rate Curve by Coincidence Factor

Conclusion

Based on the information analyzed, we conclude the following:

- Load factor alone is not a good indicator of class designations for rate structures that recover demand related costs through a demand charge.

Sensitivity to Weather

NewGen also analyzed the seasonality of each load. A comparison of load profiles shows varying sensitivity to weather given customer size. This is illustrated in Figures 2-8 through 2-11. Most significantly, the 10 kW to 50 kW group displayed the greatest sensitivity to weather compared to the other groups. This may imply that energy consumption related to cooling is a significant component of electricity usage in this group as compared to other customers.

The Percent of Load along the y-axis of these figures identifies the percent of an entire day's load used in each hour. For example, a value of 5.0 percent at 3:00 PM would indicate 5.0 percent of the day's load occurs between 3:00 PM and 4:00 PM. If the energy used during the day is 1,000 kWh, then the demand from 3:00 PM to 4:00 PM would be 5.0 percent of 1,000, or 50 kW.

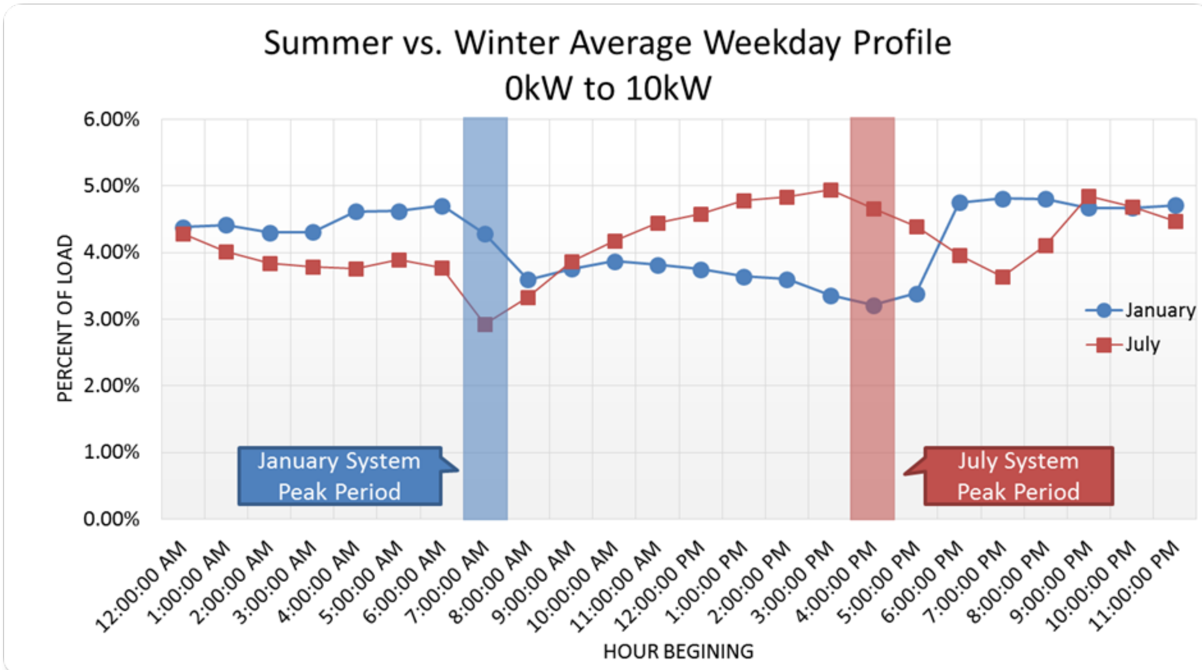


Figure 2-8. Summer vs. Winter Average Weekday Profile (0 kW to 10 kW)

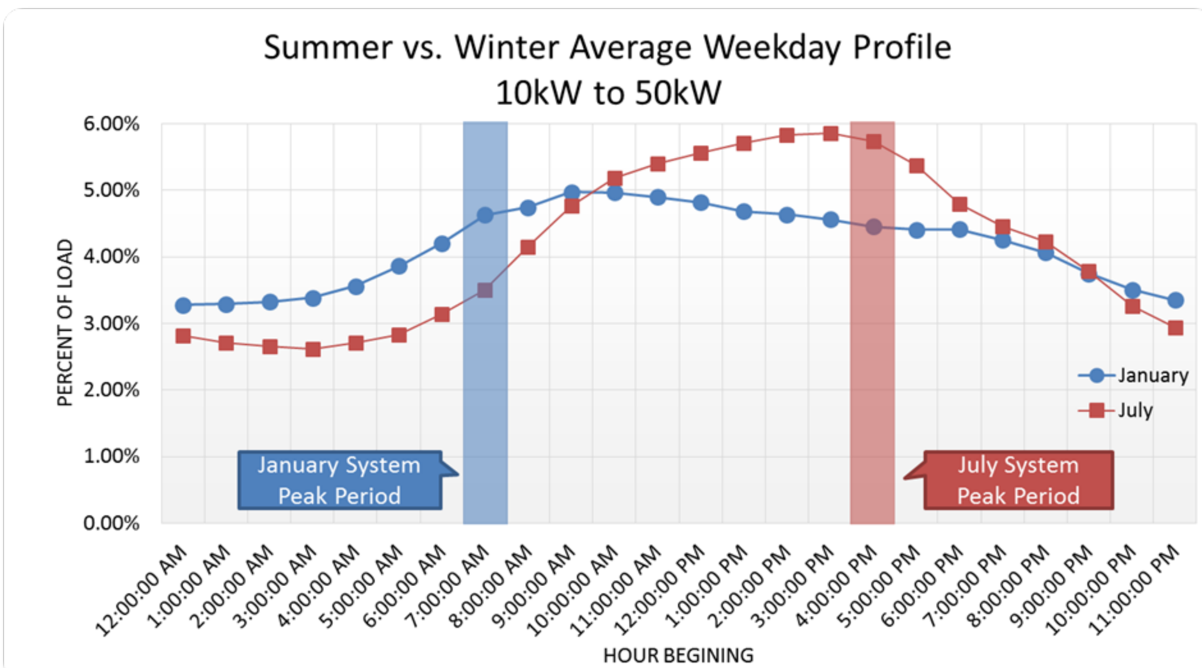


Figure 2-9. Summer vs. Winter Average Weekday Profile (10 kW to 50 kW)

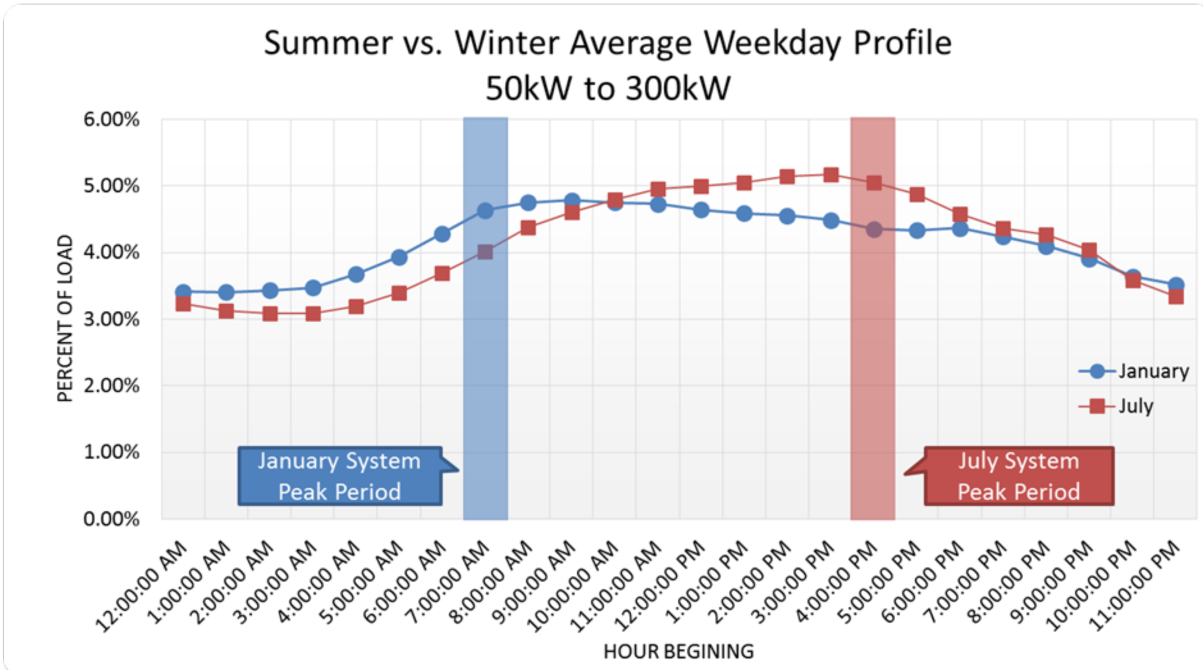


Figure 2-10. Summer vs. Winter Average Weekday Profile (50 kW to 300 kW)

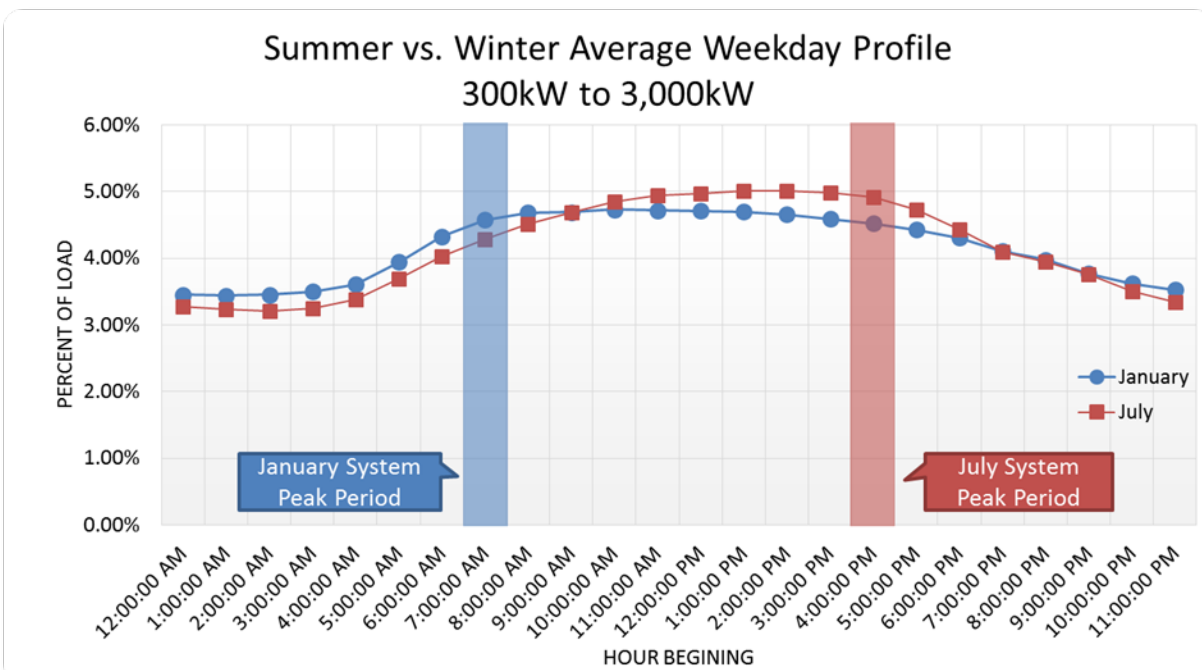


Figure 2-11. Summer vs. Winter Average Weekday Profile (300 kW to 3,000 kW)

Seasonality indicates that a 10 kW to 50 kW class may be warranted as this class contributes greatly to the summer system peak, therefore resulting in a higher demand charge, on an annual basis, as compared to other secondary voltage classes.

Conclusion

Based on the information analyzed, we conclude the following:

- The 10 kW to 50 kW class is weather sensitive and, therefore, contributes to the summer peak to a greater extent than in other monthly peaks that occur during the non-summer seasons.
- Seasonality, combined with coincidence and non-coincidence factors, supports four groups of secondary voltage customers, as follows:
  - 0 kW to 10 kW
  - 10 kW to 50 kW
  - 50 kW to 300 kW
  - > 300 kW

Market Prices

Another area of consideration evaluated by NewGen is the customer load in relation to ERCOT pricing profiles. NewGen reviewed the hourly load of all customers in the sample and weighted them by the historical settlement point price (SPP) for the same period from LZ_AEN (AE's load zone). This analysis shows if customer groups have relatively more or less energy usage during peak market periods. Results of this analysis are shown in Figure 2-12. The lowest costs are associated with the 0 kW to 10 kW group and the over 300 kW group. There is an increase in the average SPP for the 10 kW to 50 kW group and, to a lesser extent, for the 50 kW to 300 kW group.

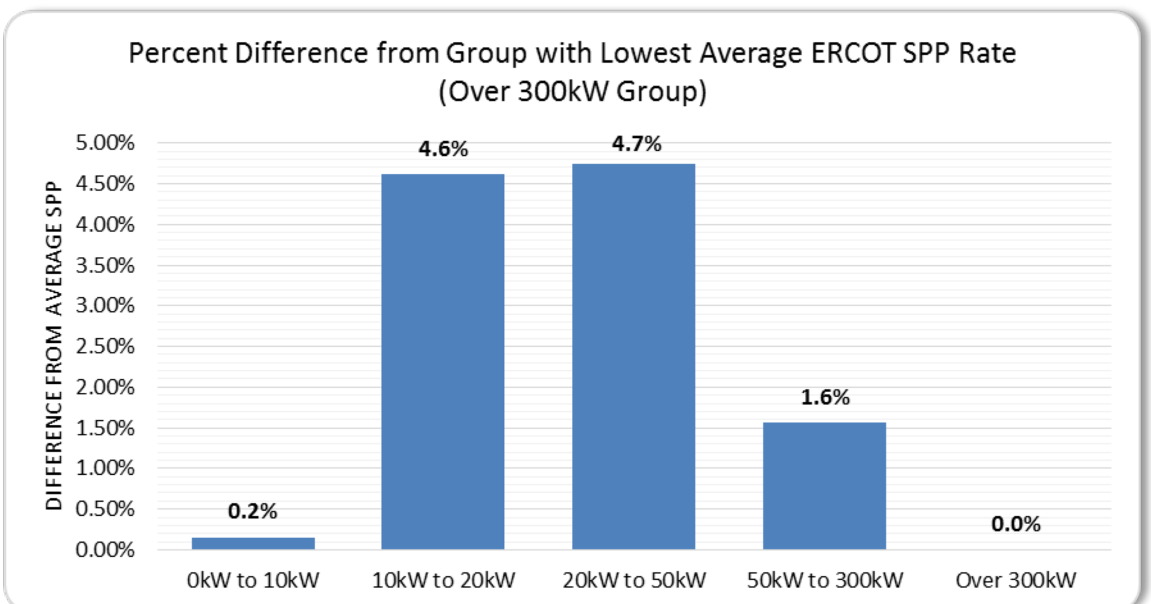


Figure 2-12. Percent Difference from Group with Lowest Average ERCOT SPP Rate (Over 300 kW Group)

Conclusion

Based on the information analyzed, we conclude the following:

- Market price differentials by group represent a differential of 4.7 percent from the highest average SPP of the 20 kW to 50 kW group and the lowest average SPP of the group representing customers with demands greater than 300 kW.
- The weighted market price costs of the 10 kW to 20 kW group are nearly identical to the 20 kW to 50 kW group.
- There is a decrease in weighted market price costs for the 50 kW to 300 kW group as compared to customers between 10 kW and 50 kW due to a higher portion of energy usage during the peak summer periods for customers between 10 kW and 50 kW.
- Price differentials are influenced by the blend of on-peak to off-peak energy use. Groups of customers with a large percentage of off-peak to on-peak energy use have the lowest percent difference from the average SPP market price.

Customer Diversity

Individual load profiles were also analyzed, as illustrated in Figures 2-13 through 2-16. The following figures compare customer load shapes on a uniform percent of load scale. Percent of load simply calculates a customer load at a given point in time as a percent of the total load summed over all time periods. This method allows for a direct comparison of customer usage behavior, without the influence of customer size, so that diversity of use can be readily identified. This analysis shows that from 0 kW to 10 kW, lighting loads with significant nighttime (i.e., off-peak) usage exist. From 10 kW to 50 kW, there is a larger portion of usage in the afternoon period as compared with the 0 kW to 10 kW group, but a large amount of diversity of loads still exists. As loads get larger than 50 kW, load diversity decreases and individual loads more closely align with the average load (the bold red line in each graph). This is most strongly seen in loads above 300 kW.

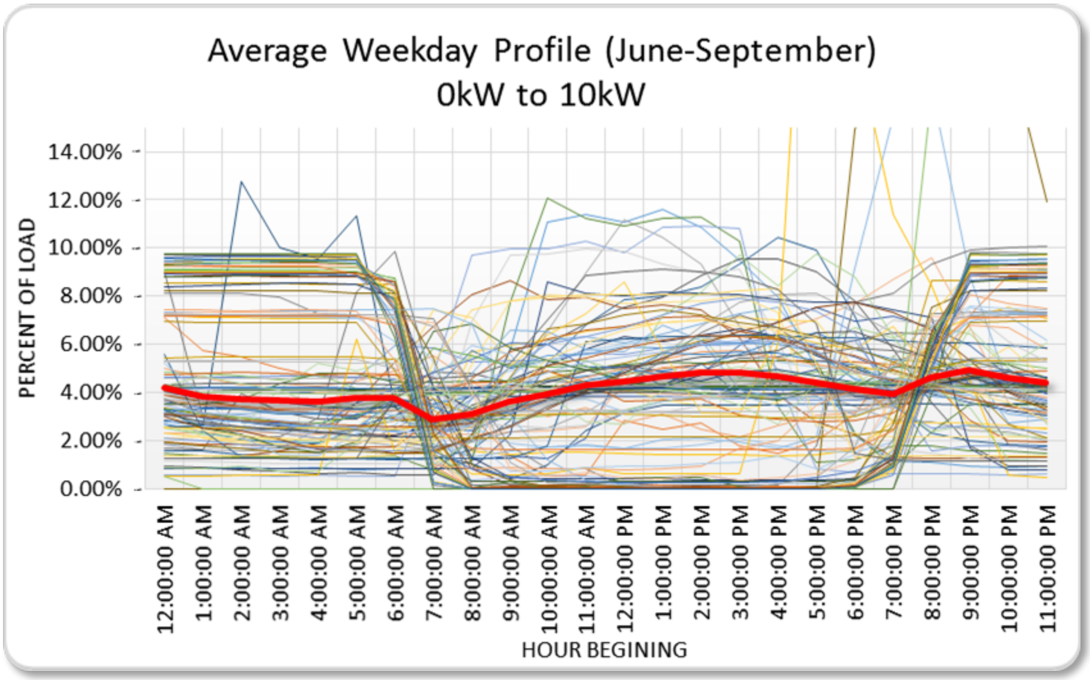


Figure 2-13. Average Weekday Profile (June – September) 0 kW to 10 kW

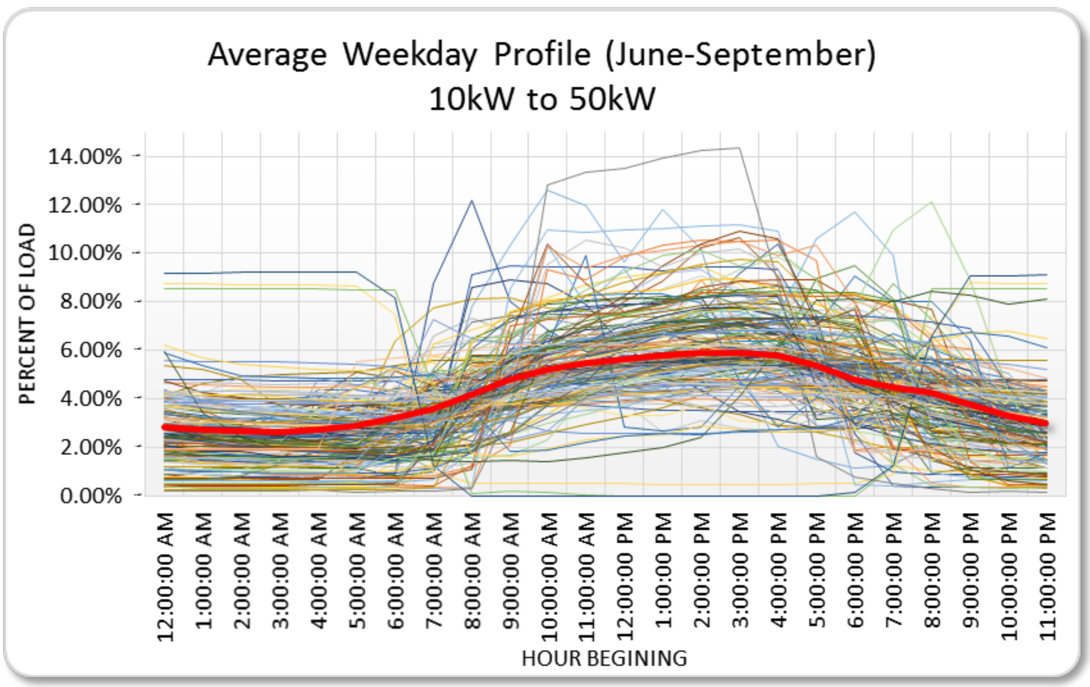


Figure 2-14. Average Weekday Profile (June – September) 10 kW to 50 kW

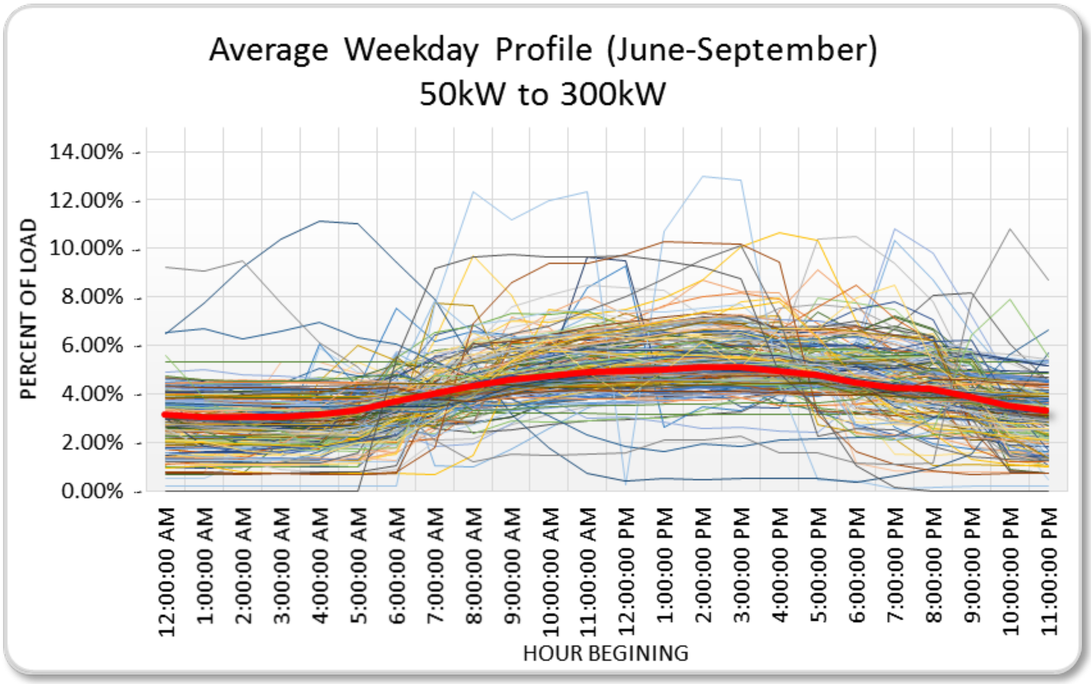


Figure 2-15. Average Weekday Profile (June – September) 50 kW to 300 kW

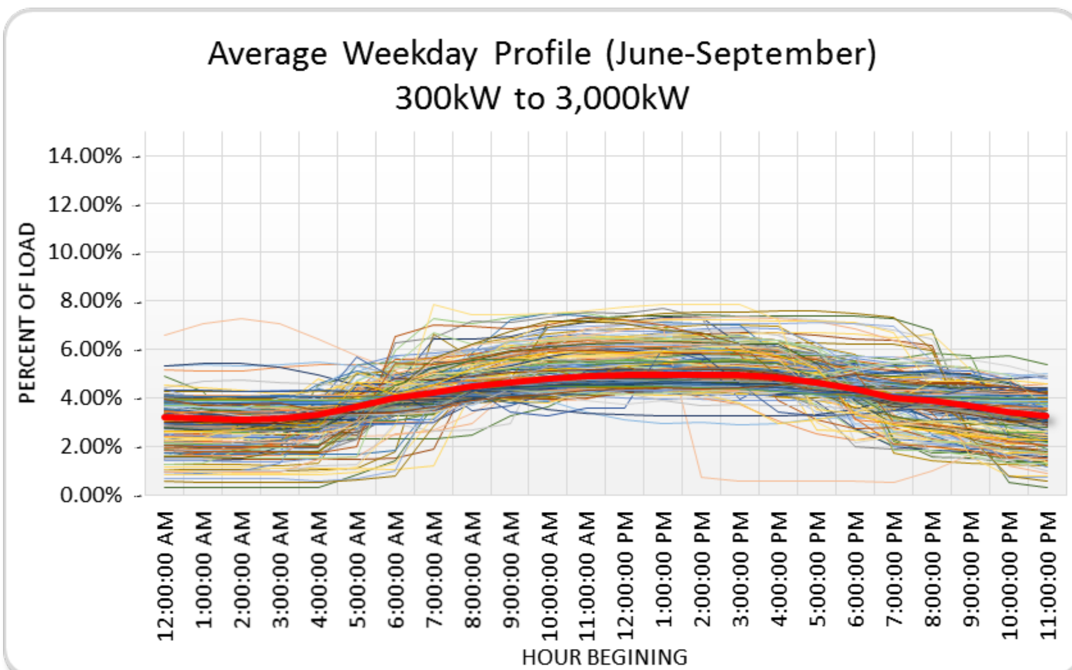


Figure 2-16. Average Weekday Profile (June – September) 300 kW to 3,000 kW

The lighting loads in the 0 kW to 10 kW range improve the demand profile for the customers included with this group because their consumption is completely off-peak. This group also has significant diversity in loads, which also benefits the class when assigning costs. If the lighting loads were included in a class composed of a larger group (e.g., 0 kW to 20 kW), their benefit would be muted because the larger loads in this more expanded group overwhelm the influence of the lighting loads. If the larger customers being added to the class had higher load factors, this might offset this influence because higher load factors decrease average costs, which is the basis for the energy-only rate structure. However, the customers in the 10 kW to 20 kW range have similar load factors to the customers in the 0 kW to 10 kW range and, therefore, these customers will not decrease average costs. Thus, expanding the existing group of customers in the range of 0 kW to 10 kW to some larger group of load sizes is expected to increase the share of demand related production costs assigned to the 0 kW to 10 kW customers and increase their cost of service.

The average loads for the four groups of customers shown in Figures 2-13 through 2-16 are graphed in Figure 2-17 to show the differences in load shapes.

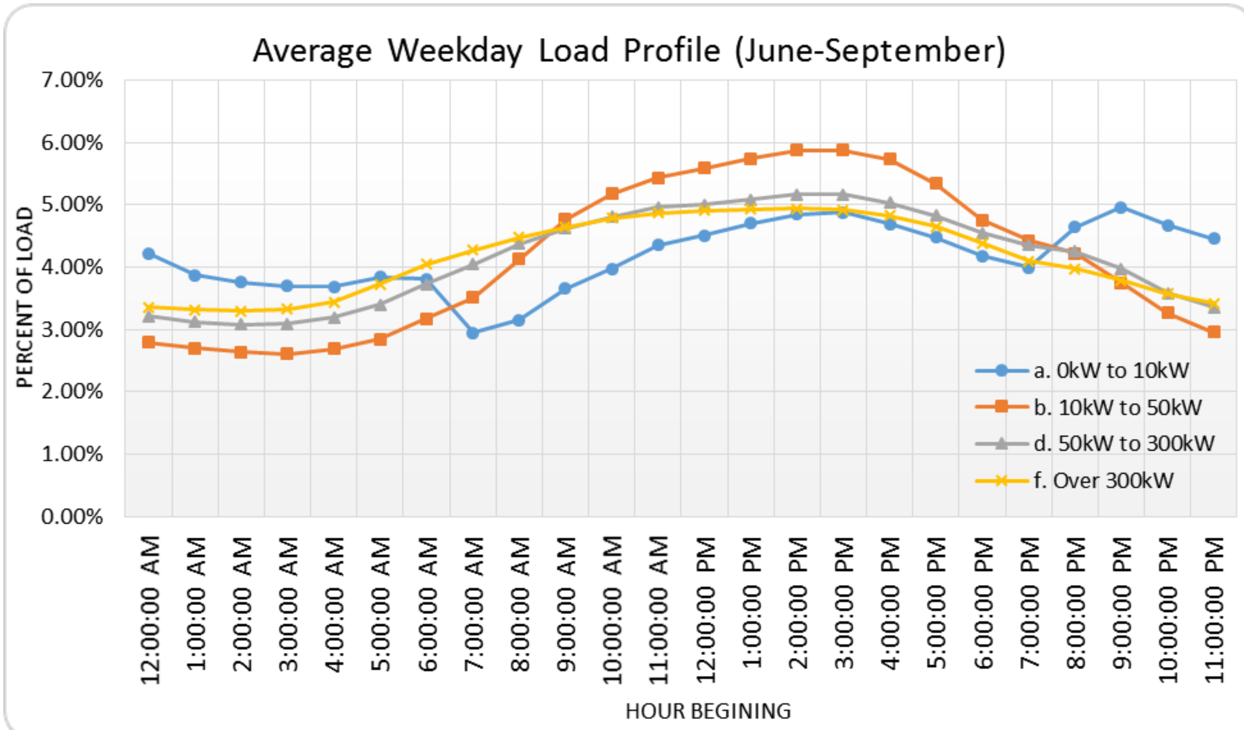


Figure 2-17. Average Weekday Load by Group (June – September)

Figure 2-17 demonstrates the significant difference in the load shape for customers in the 0 kW to 10 kW range, as compared with larger customers. This further supports the treatment of this group of customers as its own class for cost allocation and recovery.

Conclusion

Based on the information analyzed, we conclude the following:

- Customer diversity is greatest in the 0 kW to 10 kW group.
- Some diversity exists between customers with demands from 0 kW to 300 kW.
- Customer diversity is the least in the greater than 300 kW group.
- Expanding the 0 kW to 10 kW group to some larger group of load sizes is expected to increase the share of demand related production costs assigned to the 0 kW to 10 kW customers and increase their cost of service.

Distribution Costs

NewGen analyzed the cost of transformers by transformer capacity in kilovolt amps (kVa). To perform this analysis, NewGen took the book cost and vintage of AE's transformer inventory and made an adjustment to book cost to bring the cost to current dollars using the Handy Whitman Index for the South-Central region. The relationship between transformer capacity and cost is linear in nature, as shown in Figure 2-18. When costs are analyzed on a unit ($/kVa) basis, there are apparent increased unit costs seen at the 15 kVa transformer, 25 kVa transformer, and the 50 kVa transformer levels, as shown in Figure 2-19. However, after interviewing AE system planners and reviewing system design specifications, it became apparent that AE routinely connects multiple customers to a single transformer and transformer costs were not a precise enough factor to be used in the determination of customer class delineations.

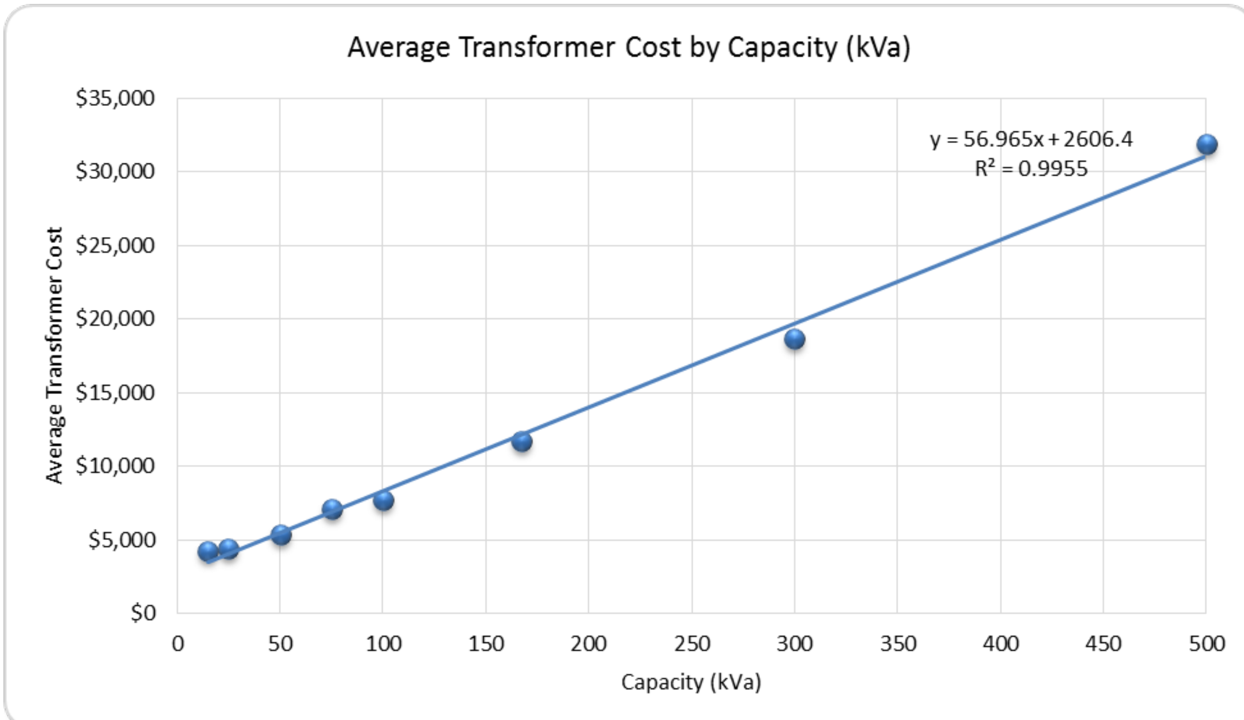


Figure 2-18. Average Transformer Cost by Capacity (kVa)

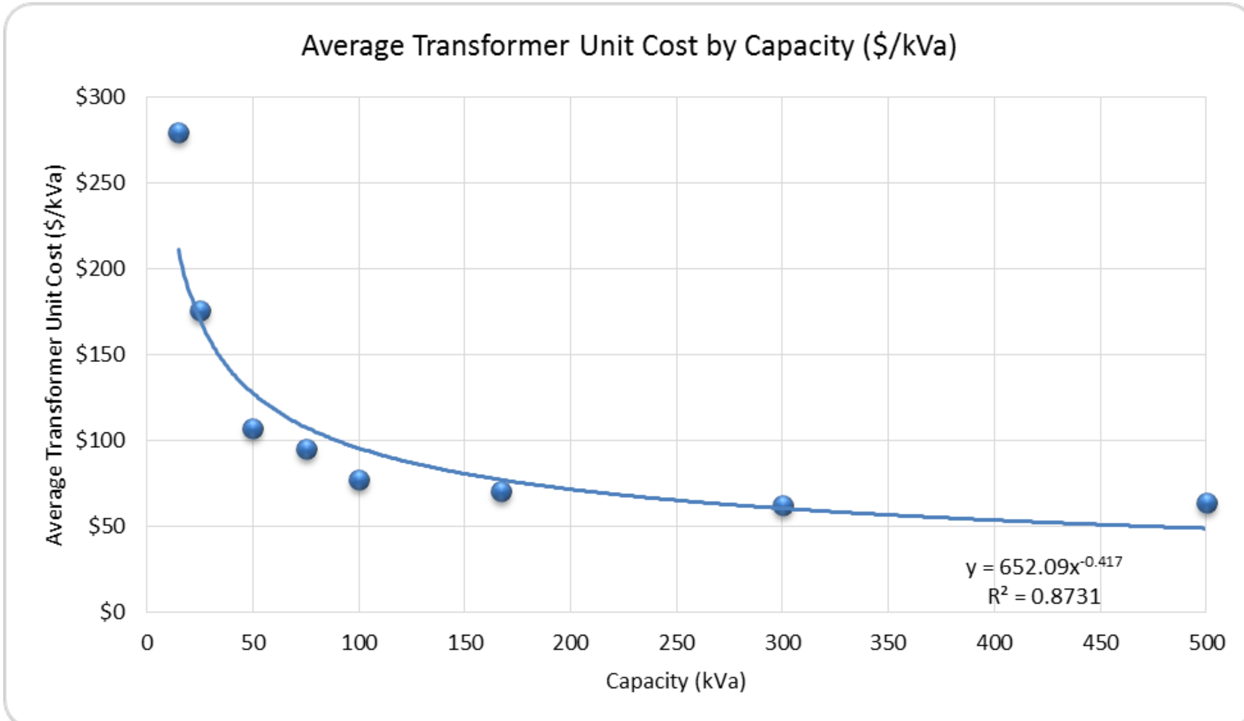


Figure 2-19. Average Transformer Unit Cost by Capacity ($/kVA)

AE does incur increased distribution costs for customers with demands greater than 3,000 kW due to the need to install special facilities or otherwise modify existing distribution systems. However, due to the limited number of secondary voltage customers with demands greater than 3,000 kW, it was determined that another, separate, class would be unnecessary for this group.

Section 3
SUMMARY

NewGen finds clear, data-supported groupings of customers in the following ranges based on analysis of coincidence to system peaks and coincidence to the 12NCP:

- 0 kW to 10 kW
- 10 kW to 300 kW
- > 300 kW

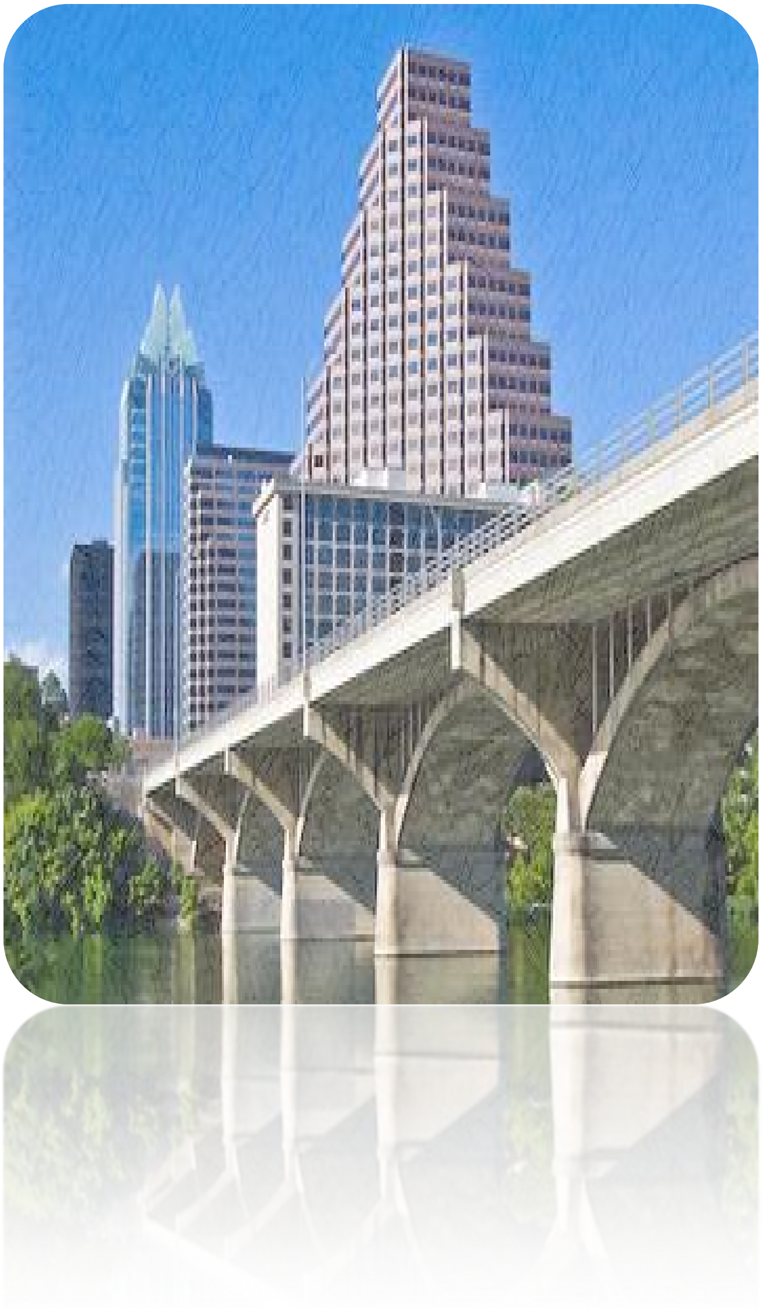
There is some support for a further division of the 10 kW to 300 kW group at 50 kW based on the consistency of load factor, on an average customer basis, up to 50 kW and the meaningful increase in load factor for customers larger than 50 kW. These groupings are further supported by the analysis comparing the customer loads in relation to ERCOT pricing profiles.

Further, based on the characteristics of the loads, expanding the existing customer class composed of customers in the 0 kW to 10 kW group to include larger loads could increase the coincidence of the class, potentially decrease diversity, and increase the allocated cost responsibility for these customers.

In an attempt to assign an objective measure to the possible groupings of secondary voltage customers, NewGen scored the identified groups based on the level of support provided by the data and our analysis. A summary of the relative influences and support for four different possible groupings of secondary voltage customers is shown in Table 3-1. As shown in the table, there is no support for a particular grouping of customers based on distribution investment. Overall, the highest support score is associated with the grouping proposed by NewGen (Option A).

Table 3-1
Support from Data for Options (0=No Support, 1=Some Support, 2=Strong Support)

	CP	NCP	LF	Market Price	Seasonality	Distribution Investment	Total
Option A							
0 kW to 10 kW	2	2	2	2	0	0	8.00
10 kW to 300 kW	2	2	0	1	0	0	5.00
Over 300 kW	2	2	2	2	1	0	9.00
Average	2.00	2.00	1.33	1.67	0.33	0.00	7.33
Option B							
0 kW to 20 kW	0	0	2	0	0	0	2.00
20 kW to 300 kW	0	0	0	0	0	0	0.00
Over 300 kW	2	2	2	2	1	0	9.00
Average	0.67	0.67	1.33	0.67	0.33	0.00	3.67
Option C							
0 kW to 10 kW	2	2	2	2	0	0	8.00
10 kW to 50 kW	0	0	1	2	2	0	5.00
50 kW to 300 kW	0	0	2	2	2	0	6.00
Over 300 kW	2	2	2	2	1	0	9.00
Average	1.00	1.00	1.75	2.00	1.25	0.00	7.00
Option D							
0 kW to 20 kW	0	0	2	0	0	0	2.00
20 kW to 50 kW	0	0	0	0	0	0	0.00
50 kW to 300 kW	0	0	2	2	2	0	6.00
Over 300 kW	2	2	2	2	1	0	9.00
Average	0.50	0.50	1.50	1.00	0.75	0.00	4.25



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Residential Service

Application:
Applies to all electric service for domestic purposes in each individual metered residence, apartment unit, mobile home, or other dwelling unit whose point of delivery is located within the limits of Austin Energy's service territory. The appropriate General Service schedules applies where a portion of the dwelling unit is used for either: a) conducting a business, or other non-domestic purposes, unless such use qualifies as a home occupation pursuant to City Code Chapter 25-2-900; or b) for separately-metered uses at the same premises, including, but not limited to: water wells, gates, barns, garages, boat docks, pools, and lighting. These rates apply to secondary voltage less than 12,470 volts nominal line to line.

Character of Service:
Service is provided under this rate schedule pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and allow reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

The rate tables below reflect rates with an effective date of October 1, 2016. For information on other applicable rates (i.e., power supply adjustment, community benefit, and regulatory), please see corresponding schedules in the tariff (if applicable). For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Discounts:
Residential customers who receive, or who reside with a household member who receives, assistance from the Comprehensive Energy Assistance Program (CEAP), Travis County Hospital District Medical Assistance Program (MAP), Supplemental Security Income Program (SSI), Medicaid, Veterans Affairs Supportive Housing (VASH), the Supplemental Nutritional Assistance Program (SNAP), the Children's Health Insurance Program (CHIP), or the Telephone Lifeline Program are eligible for a discount under the Customer Assistance Program (CAP). The priority for program funding is CEAP, MAP, SSI, Medicaid, VASH, and SNAP followed by CHIP and then Telephone Lifeline recipients. Eligible residential customers will be automatically enrolled in the discount program through a third-party matching process, with self-enrollment also available directly through Austin Energy.

Customers enrolled in the discount program are exempt from the monthly Customer Charge and the CAP component of the Community Benefit Charge and shall receive a 10 percent bill reduction on kilowatt-hour-based charges. Customers in the discount program, as well as other low income and disadvantaged residential customers, may be eligible for bill payment assistance through Plus 1 and for free weatherization assistance.

Rider Schedules:
Service under this rate schedule is eligible for application of GreenChoice® Energy (Rider) and Value-Of-Solar (Rider).

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	**Outside City Limits**
Basic Charges ($/month)		
Customer	$10.00	$10.00
Delivery	$0.00	$0.00
Energy Charges ($/kWh)		
0 – 500 kWh	$0.03300	$0.03800
501 – 1,000 kWh	$0.05600	$0.05600
1,001 – 1,500 kWh	$0.07595	$0.07815
1,501 – 2,500 kWh	$0.09100	$0.07815
Over 2,500 kWh	$0.10595	$0.07815
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03148	$0.03148
Non-Summer Power Supply (Oct – May)	$0.03124	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00172	$0.00118
Service Area Lighting	$0.00145	$0.00000
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kWh)		
Regulatory	$0.01188	$0.01188

Time-Of-Use Rates

Austin Energy has administratively suspended availability of this time-of-use rate option to additional customers; while this rate option is closed, Austin Energy offers a time-of-use option under the pilot program rate schedule. If already participating in the programs, customers will have chosen the time-of-use charges to be applied for a term of no less than twelve consecutive billing months, in lieu of the Standard Rates apply to all of Austin Energy's service territory. Customers selecting this option are not eligible to participate in levelized billing.

Time-Of-Use Periods

	Summer (June through September)	**Non-Summer** (October through May)
On-Peak Hours		
2:00 P.M. – 8:00 P.M.	Monday – Friday	None
Mid-Peak Hours		
6:00 A.M. – 2:00 P.M.	Monday – Friday	
8:00 P.M. – 10:00 P.M.	Monday – Friday	
6:00 A.M. – 10:00 P.M.	Saturday and Sunday	Everyday

Off-Peak Hours		
10:00 P.M. – 6:00 A.M.	Everyday	Everyday

Time-Of-Use Charges

	Summer (June through September)	Non-Summer (October through May)
Basic Charges ($/month)		
Customer	$12.00	$12.00
Delivery	$0.00	$0.00
Total Energy Charges ($/kWh)		
0 – 500 kWh		
Off-Peak	$0.00493	($0.00924)
Mid-Peak	$0.05040	$0.01201
On-Peak	$0.09761	$0.09761
501 – 1,000 kWh		
Off-Peak	$0.01188	($0.00427)
Mid-Peak	$0.06218	$0.03673
On-Peak	$0.11003	$0.11003
1,001 – 1,500 kWh		
Off-Peak	$0.02182	($0.00014)
Mid-Peak	$0.07134	$0.04891
On-Peak	$0.12196	$0.12196
1,501 – 2,500 kWh		
Off-Peak	$0.02679	$0.00692
Mid-Peak	$0.07934	$0.06282
On-Peak	$0.13031	$0.13031
Over 2,500 kWh		
Off-Peak	$0.06158	$0.04170
Mid-Peak	$0.09512	$0.09761
On-Peak	$0.14979	$0.14979
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03148	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00172	$0.00172
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00145	$0.00145
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kWh)		
Regulatory	$0.01188	$0.01188

General Service

Application:
Applies to all metered, non-residential secondary voltage electric service whose point of delivery is located within the limits of Austin Energy's service territory. These rates apply to secondary voltage less than 12,470 volts nominal line to line.

Character of Service:
Service is provided under these rate schedules pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

All demand (kW) is referred to as "Billed kW" and shall be measured as the metered kilowatt demand during the fifteen-minute interval of greatest use during the billing month as determined by Austin Energy's metering equipment and adjusted for power factor and load factor corrections.

When power factor during the interval of greatest use is less than 90 percent, as determined by metering equipment installed by Austin Energy, the Billed kW shall be determined by multiplying metered kilowatt demand during the fifteen-minute interval of greatest use by a 90 percent power factor divided by the actual recorded power factor during the interval of greatest use.

For example, the metered kilowatt demand during the fifteen-minute interval of greatest monthly use is 13.5 kW, and the power factor during the fifteen-minute interval of greatest monthly use is 86.7 percent; therefore, the Billed kW equals 14.0 kW (13.5 kW x 0.90 / 0.867 power factor).

When the customer's monthly load factor is below 20 percent, the Billed kW will be reduced to the level required to provide an effective load factor of 20 percent. Load factor is calculated as metered energy divided by Billed kW multiplied by number of hours within the billing month. Load factor is only for determining your Billed kW, not your placement within the proper rate schedule.

For example, assuming a customer had metered energy of 1,152 kWh, Billed kW of 16 kW, and 720 hours in the billing month, the load factor would be 10 percent [1,152 kWh ÷ (16 kW * 720 hours)]; therefore, to equal a 20 percent load factor the Billed kW would need to be reduced to 8 kW [1,152 kWh ÷ (20 percent load factor * 720 hours)].

The rate tables below reflect rates with an effective date of October 1, 2016. For information on other applicable rates (i.e., power supply adjustment, community benefit, and regulatory), please see corresponding schedules in the tariff (if applicable). For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Time-Of-Use Option

Austin Energy has administratively suspended availability of this time-of-use rate option to additional customers. If already participating in the programs, customers will have chosen the time-of-use charges to be applied for a term of no less than twelve consecutive billing months, in lieu of the Standard Rates. Charges apply to all of Austin Energy's service territory. Customers selecting this option are not eligible to participate in levelized billing.

Time-Of-Use Periods

	Summer (June through September)	**Non-Summer** (October through May)
On-Peak Hours		
2:00 P.M. – 8:00 P.M.	Monday – Friday	None
Mid-Peak Hours		
6:00 A.M. – 2:00 P.M.	Monday – Friday	
8:00 P.M. – 10:00 P.M.	Monday – Friday	
6:00 A.M. – 10:00 P.M.	Saturday and Sunday	Everyday
Off-Peak Hours		
10:00 P.M. – 6:00 A.M.	Everyday	Everyday

Discounts:
For any Independent School District, State facilities, or Military accounts the monthly customer-, delivery-, demand-, and energy-charges billed pursuant to these rate schedules will be discounted by 20 percent; all other electric charges will be billed pursuant to these rate schedules and will not be discounted.

GreenChoice® Energy Rider:
Service under these rate schedules are eligible for application of the GreenChoice® Energy (Rider).

Secondary Voltage (Demand less than 10 kW)

These rates apply to any customer whose average metered peak demand for power during the most recent June through September billing months did not meet or exceed 10 kW. If a customer has insufficient usage history to determine the appropriate rate schedule, Austin Energy will place the customer. Demand data will be reviewed annually in October.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	**Outside City Limits**
Basic Charges ($/month)		
Customer	$18.00	$18.00
Delivery	$0.00	$0.00
Energy Charges ($/kWh)		
All Billed kWhs	$0.05190	$0.05190

Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03148	$0.03148
Non-Summer Power Supply (Oct – May)	$0.03124	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00145	$0.00000
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kWh)		
Regulatory	$0.01188	$0.01188

Time-Of-Use Rates

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges ($/month)		
Customer	$18.00	$18.00
Delivery	$0.00	$0.00
Total Energy Charges ($/kWh)		
Off-Peak	$0.00798	$0.00798
Mid-Peak	$0.06336	$0.06336
On-Peak	$0.12437	$0.12437
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03148	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00145	$0.00145
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kWh)		
Regulatory	$0.01188	$0.01188

Secondary Voltage (Demand greater than or equal to 10 kW but less than 300 kW)

These rates apply to any customer whose average metered peak demand for power during the most recent June through September billing months met or exceeded 10 kW but did not meet or exceed 300 kW. If a customer has insufficient usage history to determine the appropriate rate schedule, Austin Energy will place the customer. Demand data will be reviewed annually in October.

These rates shall apply for no less than twelve months following the last month in which the required average summer metered peak demand level was met. The twelve month requirement may be waived by Austin Energy, if a customer has made significant changes in their connected load, which prevents the customer from meeting or exceeding the minimum-metered demand threshold of this rate schedule and Austin Energy has verified these changes.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	Outside City Limits
Basic Charges		
Customer ($/month)	$27.50	$27.50
Delivery ($/kW)	$4.00	$4.00
Demand Charges ($/kW)		
All Billed kWs	$5.75	$5.75
Energy Charges *($/kWh)*		
All Billed kWhs	$0.02421	$0.02356
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03148	$0.03148
Non-Summer Power Supply (Oct – May)	$0.03124	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00145	$0.00000
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kW)		
Regulatory	$3.18	$3.18

Time-Of-Use Rates

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$27.50	$27.50
Delivery ($/kW)	$4.00	$4.00
Demand Charges ($/kW)		
All Billed kWs	$5.75	$5.75
Energy Charges ($/kWh)		
Off-Peak	($0.00067)	($0.00067)
Mid-Peak	$0.03912	$0.03912
On-Peak	$0.06544	$0.06544

Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03148	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00145	$0.00145
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kW)		
Regulatory	$3.18	$3.18

Secondary Voltage (Demand greater than or equal to 300 kW)

These rates apply to any customer whose average metered peak demand for power during the most recent June through September billing months met or exceeded 300 kW. If a customer has insufficient usage history to determine the appropriate rate schedule, Austin Energy will place the customer. Demand data will be reviewed annually in October.

These rates shall apply for not less than twelve months following the last month in which the required average summer metered peak demand level was met. The twelve month requirement may be waived by Austin Energy, if a customer has made significant changes in their connected load, which prevents the customer from meeting or exceeding the minimum-metered demand threshold of this rate schedule and Austin Energy has verified these changes.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	Outside City Limits
Basic Charges		
Customer ($/month)	$71.50	$71.50
Delivery ($/kW)	$4.50	$4.50
Demand Charges ($/kW)		
All Billed kWs	$7.25	$7.25
Energy Charges *($/kWh)*		
All Billed kWhs	$0.01955	$0.01902
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03148	$0.03148
Non-Summer Power Supply (Oct – May)	$0.03124	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00145	$0.00000

Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kW)		
Regulatory	$3.18	$3.18

Time-Of-Use Rates

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$71.50	$71.50
Delivery ($/kW)	$4.50	$4.50
Demand Charges ($/kW)		
All Billed kWs	$7.25	$7.25
Energy Charges ($/kWh)		
Off-Peak	($0.00222)	($0.00222)
Mid-Peak	$0.03565	$0.03565
On-Peak	$0.06070	$0.06070
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03148	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00145	$0.00145
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kW)		
Regulatory	$3.18	$3.18

Large General Service

Application:
Applies to all primary voltage electric service whose point of delivery is located within the limits of Austin Energy's service territory. These rates apply to primary voltage between 12,470 and 69,000 volts nominal line to line.

Character of Service:
Service is provided under these rate schedules pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
The customer shall own, maintain, and operate all facilities and equipment on the customer's side of the point of delivery. Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

All demand (kW) is referred to as "Billed kW" and shall be measured as the metered kilowatt demand during the fifteen-minute interval of greatest use during the billing month as determined by Austin Energy's metering equipment and adjusted for power factor corrections.

When the power factor during the interval of greatest use is less than 90 percent, as determined by metering equipment installed by Austin Energy, the Billed kW shall be determined by multiplying the metered kilowatt demand during the fifteen-minute interval of greatest use by a 90 percent power factor divided by the actual recorded power factor during the interval of greatest use.

For example, the metered kilowatt demand during the fifteen-minute interval of greatest monthly use is 10,350 kW, and the power factor during the fifteen-minute interval of greatest monthly use is 86.7 percent; therefore, the Billed kW equals 10,744 kW (10,350 kW x 0.90 / 0.867 power factor).

The rate tables below reflect rates with an effective date of October 1, 2016. For information on other applicable rates (i.e., power supply adjustment, community benefit, and regulatory), please see corresponding schedules in the tariff (if applicable). For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Time-Of-Use Rates:
Austin Energy has administratively suspended availability of this time-of-use rate option to additional customers. If already participating in the programs, customers will have chosen the time-of-use charges to be applied for a term of no less than twelve consecutive billing months, in lieu of the Standard Rates Charges apply to all of Austin Energy's service territory. Customers selecting this option are not eligible to participate in levelized billing.

Time-Of-Use Periods:

	Summer (June through September)	**Non-Summer** (October through May)

On-Peak Hours		
2:00 P.M. – 8:00 P.M.	Monday – Friday	None
Mid-Peak Hours		
6:00 A.M. – 2:00 P.M.	Monday – Friday	
8:00 P.M. – 10:00 P.M.	Monday – Friday	
6:00 A.M. – 10:00 P.M.	Saturday and Sunday	Everyday
Off-Peak Hours		
10:00 P.M. – 6:00 A.M.	Everyday	Everyday

Discounts:
For any Independent School District, State facilities, or Military accounts the monthly customer-, delivery-, demand-, and energy-charges billed pursuant to these rate schedules will be discounted by 20 percent; all other electric charges will be billed pursuant to these rate schedules and will not be discounted.

GreenChoice® Energy Rider:
Service under these rate schedules is eligible for application of the GreenChoice® Energy (Rider).

Primary Voltage (Demand less than 3 MW)

These rates apply to any customer whose average metered peak demand for power during the most recent June through September billing months did not meet or exceed 3,000 kW. If a customer has insufficient usage history to determine the appropriate rate schedule, Austin Energy will place the customer. Demand data will be reviewed annually in October.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	Outside City Limits
Basic Charges		
Customer ($/month)	$275.00	$275.00
Delivery ($/kW)	$3.50	$3.50
Demand Charges ($/kW)		
All Billed kWs	$8.50	$8.50
Energy Charges *($/kWh)*		
All Billed kWhs	$0.00500	$0.00487
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03076	$0.03076
Non-Summer Power Supply (Oct – May)	$0.03053	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065

Service Area Lighting	$0.00141	$0.00000
Energy Efficiency Services	$0.00240	$0.00240
Regulatory Charge ($/kW)		
Regulatory	$3.11	$3.11

Time-Of-Use Rates

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$275.00	$275.00
Delivery ($/kW)	$3.50	$3.50
Demand Charges ($/kW)		
All Billed kWs	$8.50	$8.50
Energy Charges ($/kWh)		
Off-Peak	($0.00862)	($0.00862)
Mid-Peak	$0.02042	$0.02042
On-Peak	$0.03963	$0.03963
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03076	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00141	$0.00141
Energy Efficiency Services	$0.00240	$0.00240
Regulatory Charge ($/kW)		
Regulatory	$3.11	$3.11

Primary Voltage (Demand greater than or equal to 3 MW and less than 20 MW)

These rates apply to any customer whose average metered peak demand for power during the most recent June through September billing months met or exceeded 3,000 kW but did not meet or exceed 20,000 kW. If a customer has insufficient usage history to determine the appropriate rate schedule, Austin Energy will place the customer. Demand data will be reviewed annually in October.

These rates shall apply for no less than twelve months following the last month in which the required average summer metered peak demand level was met. The twelve month requirement may be waived by Austin Energy, if a customer has made significant changes in their connected load, which prevents the customer from meeting or exceeding the minimum-metered kW threshold of this rate schedule and Austin Energy has verified these changes. Dual Feed Service charges are not applicable to this rate schedule.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	Outside City Limits
Basic Charges		
Customer ($/month)	$2,200.00	$2,200.00
Delivery ($/kW)	$4.00	$4.00
Demand Charges ($/kW)		
All Billed kWs	$9.50	$9.50
Energy Charges ($/kWh)		
All Billed kWhs	$0.00360	$0.00350
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03076	$0.03076
Non-Summer Power Supply (Oct – May)	$0.03053	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00141	$0.00000
Energy Efficiency Services	$0.00240	$0.00240
Regulatory Charge ($/kW)		
Regulatory	$3.11	$3.11

Time-Of-Use Rates

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$2,200.00	$2,200.00
Delivery ($/kW)	$4.00	$4.00
Demand Charges ($/kW)		
All Billed kWs	$9.50	$9.50
Energy Charges ($/kWh)		
Off-Peak	($0.01211)	($0.01211)
Mid-Peak	$0.01263	$0.01263
On-Peak	$0.02899	$0.02899
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03076	$0.03053
Community Benefit Charges ($/kWh)		

Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00141	$0.00141
(Only applies to Inside City Limits Accounts)		
Energy Efficiency Services	$0.00240	$0.00240
Regulatory Charge ($/kW)		
Regulatory	$3.11	$3.11

Primary Voltage (Demand greater than or equal to 20 MW)

This rate apply to any customer whose average metered peak demand for power during the most recent June through September billing months met or exceeded 20,000 kW. If a customer has insufficient usage history to determine the appropriate rate schedule, Austin Energy will place the customer. Demand data will be reviewed annually in October.

This rate shall apply for no less than twelve months following the last month in which the required average summer metered peak demand level was met. The twelve month requirement may be waived by Austin Energy, if a customer has made significant changes in their connected load, which prevents the customer from meeting or exceeding the minimum metered kW threshold of this rate schedule and these changes have been verified by Austin Energy. Dual Feed Service charges are not applicable to this rate schedule.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	Outside City Limits
Basic Charges		
Customer ($/month)	$2,750.00	$2,750.00
Delivery ($/kW)	$4.50	$4.50
Demand Charges ($/kW)		
All Billed kWs	$10.25	$10.25
Energy Charges ($/kWhs)		
All Billed kWhs	$0.00300	$0.00300
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03076	$0.03076
Non-Summer Power Supply (Oct – May)	$0.03053	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00141	$0.00000
Energy Efficiency Services	$0.00240	$0.00240
Regulatory Charge ($/kW)		
Regulatory	$3.11	$3.11

Time-Of-Use Rates

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$2,750.00	$2,750.00
Delivery ($/kW)	$4.50	$4.50
Demand Charges ($/kW)		
All Billed kWs	$10.25	$10.25
Energy Charges ($/kWh)		
Off-Peak	($0.01302)	($0.01302)
Mid-Peak	$0.01057	$0.01057
On-Peak	$0.02618	$0.02618
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03076	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00141	$0.00141
Energy Efficiency Services	$0.00240	$0.00240
Regulatory Charge ($/kW)		
Regulatory	$3.11	$3.11

High Load Factor Primary Voltage (Demand greater than or equal to 20 MW)

This rate apply to any customer whose average monthly billed demand for power met or exceeded 20,000 kW and has an annual average monthly load factor of at least 85 percent.

Contract Term:
For a term ending at the end of the billing month that includes October 31, 2024, the customer shall enter into an exclusive sole supplier agreement to purchase its entire bundled electric service requirements for the facilities and equipment at the account service location, with an exception for on-site back-up generation and up to 1 MW of on-site renewable generation capacity. The City Manager or his designee may establish and agree to terms and conditions for a service contract.

Block Power Supply Pricing:
In lieu of the Power Supply Adjustment, the customer's service contract may provide a fixed power supply charge for a monthly block quantity of energy for a defined term, based on the cost of wholesale power market prices. Block pricing is contingent on the availability of authorized funding and the

customer's satisfaction of credit requirements. All billed energy not subject to block pricing is subject to the variable Power Supply Adjustment (or Green Choice Energy rider), as may be amended from time to time, or any other successor power or fuel adjustment schedules.

The kWh block price shall be the actual wholesale kWh cost to Austin Energy of the block quantity supplied, plus a renewable portfolio charge based upon the forecast kWh price of renewable energy credits in the ERCOT market during the term of the block pricing.

In lieu of the renewable portfolio charge, the customer may opt to designate an equal renewable portfolio dollar value as a monthly block quantity of GreenChoice Energy by paying the per-kWh price difference between the wholesale power price paid by Austin Energy and the applicable GreenChoice Charge for the specified quantity.

Minimum Bill:
The minimum monthly bill is the highest billed demand established during the most recent 12-month billing period multiplied by the Summer Demand Charge, in addition to any associated fuel, power supply, or block pricing charges.

Maximum Community Benefit Charges:
During the term of a service contract, Customer Assistance Program charges shall not exceed $200,000 during any fiscal year of October 1 through September 30 (prorated for any partial fiscal year). Charges for Service Area Lighting and Energy Efficiency Services (EES) do not apply under this rate schedule.

Terms and Conditions:
This schedule is effective through the end of the customer's billing month that includes October 31, 2024. Austin Energy may provide service under this schedule as a bundled entity or, if retail deregulation is implemented in its service area, as separate, unbundled entities. The customer is ineligible for participation in energy efficiency, retail demand response, and renewable energy incentive programs. Billed amounts due and owing shall incur a penalty of one percent per month until paid.

Average annual monthly load factor is the sum of the customer's load factor percentages for the previous twelve billing months divided by twelve. Verified reductions in energy consumption made in response to a request for Emergency Response Service or another demand response program operated by ERCOT shall be credited in calculating load factor. Dual Feed Service charges are not applicable to this rate schedule.

Standard Rates

Basic, energy, demand, and community benefits charges will be fixed for the initial contract period ending October 31, 2018. The Austin City Council may amend these charges to be fixed for the period November 1, 2018, through October 31, 2021, and again for the period November 1, 2021, through October 31, 2024.

If, during the initial contract period ending October 31, 2018, the City Council adopts new base electric rates for customers receiving service at primary voltage based upon a comprehensive cost-of-service study, the customer may opt to have its contract rates adjusted to any applicable new rates during the initial contract term.

Regulatory charge will remain fixed for the initial contract period ending October 31, 2018. For each subsequent three-year period, the regulatory charge will be reset and fixed in accordance with the regulatory charge schedule, plus an adjustment for any over- or under-recovery of regulatory charges from the previous three-year period. The regulatory charge may be adjusted during any three-year period if an over-recovery of more than 110 percent or an under-recovery of less than 90 percent of costs occurs.

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$15,470.00	$15,470.00
Delivery ($/kW)	$4.50	$4.50
Demand Charges ($/kW)		
All Billed kWs	$11.51	$11.51
Energy Charges ($/kWh)		
All Billed kWhs	$0.00000	$0.00000
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03076	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Regulatory Charge ($/kW)		
All Billed kWs	$3.90	$3.90

For sign contract agreements with effective dates before October 1, 2016.

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$12,000.00	$12,000.00
Delivery ($/kW)	$3.75	$3.75
Demand Charges ($/kW)		
All Billed kWs	$11.10	$11.10
Energy Charges ($/kWh)		
All kWhs	$0.00370	$0.00370
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03076	$0.03053
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Regulatory Charges ($/kW)		
All Billed kWs	$5.18	$5.18

Transmission Service

Application:
Applies to all transmission voltage electric service at 69,000 volts or above nominal line to line, and whose point of delivery is located within the limits of Austin Energy's service territory.

Character of Service:
Service is provided under this rate schedule pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
The customer shall own, maintain, and operate all facilities and equipment on the customer's side of the point of delivery. Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

All demand (kW) is referred to as "Billed kW" and shall be measured as the metered kilowatt demand during the fifteen-minute interval of greatest use during the billing month as determined by Austin Energy's metering equipment, adjusted for power factor corrections.

When the power factor during the interval of greatest use is less than 90 percent, as determined by metering equipment installed by Austin Energy, the Billed kW shall be determined by multiplying metered kilowatt demand during the fifteen-minute interval of greatest use by a 90 percent power factor divided by the actual recorded power factor during the interval of greatest use.

For example, the metered kilowatt demand during the fifteen-minute interval of greatest monthly use is 31,000 kW, and the power factor during the fifteen-minute interval of greatest monthly use is 86.7 percent; therefore, the Billed kW equals 32,180 kW (31,000 kW x 0.90 / 0.867 power factor).

The rate tables below reflect rates with an effective date of October 1, 2016. For information on other applicable rates (i.e., power supply adjustment, community benefit, and regulatory), please see corresponding schedules in the tariff (if applicable). For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Discounts:
For any Independent School District, State facilities, or Military accounts the monthly customer-, delivery-, demand-, and energy-charges billed pursuant to these rate schedules will be discounted by 20 percent; all other electric charges will be billed pursuant to these rate schedules and will not be discounted.

GreenChoice® Energy Rider:
Service under this rate schedule is eligible for application of the GreenChoice® Energy (Rider).

Transmission Voltage

These rates apply to any customer whose metered demand is at 69,000 volts or above nominal line to line.

Standard Rates

This is the default rate option under this schedule.

	Inside City Limits	Outside City Limits
Basic Charges		
Customer ($/month)	$2,750.00	$2,750.00
Delivery ($/kW)	$0.00	$0.00
Demand Charges ($/kW)		
All Billed kWs	$12.00	$12.00
Energy Charges *($/kWh)*		
All Billed kWhs	$0.00500	$0.00500
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03037	$0.03037
Non-Summer Power Supply (Oct – May)	$0.03015	$0.03015
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting	$0.00139	$0.00000
Energy Efficiency Services	$0.00237	$0.00237
Regulatory Charge ($/kW)		
Regulatory	$3.07	$3.07

Time-Of-Use Rates

Austin Energy has administratively suspended availability of this time-of-use rate option to additional customers. If already participating in the programs, customers will have chosen the time-of-use charges to be applied for a term of no less than twelve consecutive billing months, in lieu of the Standard Rates Charges apply to all of Austin Energy's service territory. Customers selecting this option are not eligible to participate in levelized billing.

Time-Of-Use Periods

	Summer (June through September)	**Non-Summer** (October through May)
On-Peak Hours		
2:00 P.M. – 8:00 P.M.	Monday – Friday	None
Mid-Peak Hours		
6:00 A.M. – 2:00 P.M.	Monday – Friday	

8:00 P.M. – 10:00 P.M.	Monday – Friday	
6:00 A.M. – 10:00 P.M.	Saturday and Sunday	Everyday
Off-Peak Hours		
10:00 P.M. – 6:00 A.M.	Everyday	Everyday

Time-Of-Use Charges

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$2,750.00	$2,750.00
Delivery ($/kW)	$0.00	$0.00
Demand Charges ($/kW)		
All Billed kWs	$12.00	$12.00
Energy Charges ($/kWh)		
Off-Peak	($0.00974)	($0.00974)
Mid-Peak	$0.01741	$0.01741
On-Peak	$0.03537	$0.03537
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03037	$0.03015
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00139	$0.00139
Energy Efficiency Services	$0.00237	$0.00237
Regulatory Charge ($/kW)		
Regulatory	$3.07	$3.07

High Load Factor Transmission Voltage (Demand greater than or equal to 20 MW)

This rate apply to any customer whose average monthly billed demand for power met or exceeded 20,000 kW and has an annual average monthly load factor of at least 85 percent.

Contract Term:
For a term ending at the end of the billing month that includes October 31, 2024, the customer shall enter into an exclusive sole supplier agreement to purchase its entire bundled electric service requirements for the facilities and equipment at the account service location, with an exception for on-site back-up generation and up to 1 MW of on-site renewable generation capacity. The City Manager or his designee may establish and agree to terms and conditions for a service contract.

Block Power Supply Pricing:
In lieu of the Power Supply Adjustment, the customer's service contract may provide a fixed power supply charge for a monthly block quantity of energy for a defined term, based on the cost of wholesale power market prices. Block pricing is contingent on the availability of authorized funding and the customer's satisfaction of credit requirements. All billed energy not subject to block pricing is subject to the variable Power Supply Adjustment (or Green Choice Energy rider), as may be amended from time to time, or any other successor power or fuel adjustment schedules.

The kWh block price shall be the actual wholesale kWh cost to Austin Energy of the block quantity supplied, plus a renewable portfolio charge based upon the forecast kWh price of renewable energy credits in the ERCOT market during the term of the block pricing.

In lieu of the renewable portfolio charge, the customer may opt to designate an equal renewable portfolio dollar value as a monthly block quantity of GreenChoice Energy by paying the per-kWh price difference between the wholesale power price paid by Austin Energy and the applicable GreenChoice Charge for the specified quantity.

Minimum Bill:
The minimum monthly bill is the highest billed demand established during the most recent 12-month billing period multiplied by the Summer Demand Charge, in addition to any associated fuel, power supply, or block pricing charges.

Maximum Community Benefit Charges:
During the term of a service contract, Customer Assistance Program charges shall not exceed $200,000 during any fiscal year of October 1 through September 30 (prorated for any partial fiscal year). Charges for Service Area Lighting and Energy Efficiency Services (EES) do not apply under this rate schedule.

Terms and Conditions:
This schedule is effective through the end of the customer's billing month that includes October 31, 2024. Austin Energy may provide service under this schedule as a bundled entity or, if retail deregulation is implemented in its service area, as separate, unbundled entities. The customer is ineligible for participation in energy efficiency, retail demand response, and renewable energy incentive programs. Billed amounts due and owing shall incur a penalty of one percent per month until paid.

Average annual monthly load factor is the sum of the customer's load factor percentages for the previous twelve billing months divided by twelve. Verified reductions in energy consumption made in response to a request for Emergency Response Service or another demand response program operated by ERCOT shall be credited in calculating load factor.

Standard Rates

Basic, energy, demand, and community benefits charges will be fixed for the initial contract period ending October 31, 2018. The Austin City Council may amend these charges to be fixed for the period November 1, 2018, through October 31, 2021, and again for the period November 1, 2021, through October 31, 2024.

If, during the initial contract period ending October 31, 2018, the City Council adopts new base electric rates for customers receiving service at transmission voltage based upon a comprehensive cost-of-service study, the customer may opt to have its contract rates adjusted to any applicable new rates during the initial contract term.

Regulatory charge will remain fixed for the initial contract period ending October 31, 2018. For each subsequent three-year period, the regulatory charge will be reset and fixed in accordance with the regulatory charge schedule, plus an adjustment for any over- or under-recovery of regulatory charges from the previous three-year period. The regulatory charge may be adjusted during any three-year period if an over-recovery of more than 110 percent or an under-recovery of less than 90 percent of costs occurs.

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$21,120.00	$21,120.00
Demand Charges ($/kW)		
All Billed kWs	$11.33	$11.33
Energy Charges ($/kWh)		
All Billed kWhs	$0.00115	$0.00115
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03037	$0.03015
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Regulatory Charge ($/kW)		
All Billed kWs	$3.99	$3.99

For sign contract agreements with effective dates before October 1, 2016.

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges		
Customer ($/month)	$2,500.00	$2,500.00
Demand Charges ($/kW)		
All Billed kWs	$10.06	$9.10
Energy Charges ($/kWh)		
All Billed kWhs	$0.00476	$0.00276
Power Supply Adjustment Charge ($/kWh)		
Power Supply	$0.03037	$0.03015
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00065	$0.00065
Regulatory Charges ($/kW)		
All Billed kWs	$4.12	$4.12

Lighting

Application:
Applies to any customer whose point of delivery is located within the limits of Austin Energy's service territory.

Character of Service:
Service provided under these rate schedules are pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

The rate tables below reflect rates with an effective date of October 1, 2016. For information on other applicable rates (i.e., power supply adjustment, community benefit, and regulatory), please see corresponding schedules in the tariff (if applicable). For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Discounts:
For any Independent School District, State facilities, or Military accounts the monthly customer-, delivery-, demand-, and energy-charges billed pursuant to these rate schedules will be discounted by 20 percent; all other electric charges will be billed pursuant to these rate schedules and will not be discounted.

GreenChoice® Energy Rider:
Service under these rate schedules are eligible for application of the GreenChoice® Energy (Rider).

Customer-Owned, Non-Metered Lighting

This rate applies to non-metered electric service to the Texas Department of Transportation for sign lighting and safety illumination at various locations.

	Summer (June through September)	**Non-Summer** (October through May)
Energy Charges ($/kWh)		
All Billed kWh	$0.02604	$0.02604
Power Supply Adjustment Charge ($/kWh)		
All Billed kWh	$0.03148	$0.03124

Customer-Owned, Metered Lighting

This rate applies to electric service to metered athletic field accounts whose connected load is more than 85 percent attributable to lighting, as verified by Austin Energy.

	Summer (June through September)	Non-Summer (October through May)
Basic Charges ($/month)		
Customer	$15.00	$15.00
Delivery	$0.00	$0.00
Energy Charges ($/kWh)		
All Billed kWh	$0.06175	$0.06175
Power Supply Adjustment Charge ($/kWh)		
All Billed kWh	$0.03148	$0.03124

City of Austin - Owned Outdoor Lighting

This rate applies to electric service to non-metered outdoor lighting owned and operated by the City of Austin other than Service Area Lighting.

	Summer (June through September)	Non-Summer (October through May)
Fixture Charges ($/fixture/month)		
100 Watt or Less (Billable 35 kWh)	$7.03	$7.03
101 - 175 Watt (Billable 60 kWh)	$12.05	$12.05
176 - 250 Watt (Billable 90 kWh)	$18.07	$18.07
251 Watt or Greater (Billable 140 kWh)	$28.12	$28.12
Power Supply Adjustment Charge ($/kWh)		
All Billed kWh	$0.03148	$0.03124

Service Area Lighting

This rate applies to electric service for illumination and the operation of traffic signals on all public streets, highways, expressways, or thoroughfares; other than non-metered lighting maintained by the Texas Department of Transportation. Revenues received through the Service Area Lighting component of the Community Benefit Charge are applied to offset these charges inside the City of Austin.

	Summer (June through September)	Non-Summer (October through May)
Energy Charges ($/kWh)		
All Billed kWh	$0.23219	$0.23219
Power Supply Adjustment Charge ($/kWh)		
All Billed kWh	$0.03148	$0.03124

Power Supply Adjustment

Application:
Applies to all electric service whose point of delivery is located within the limits of Austin Energy's service territory, unless otherwise stated.

Character of Service:
The Power Supply Adjustment (PSA) provides for the recovery of the preceding year's expenditures for Electric Reliability Council of Texas (ERCOT) settlements, fuel costs, net purchased power agreement costs, and any adjustment for the over- or under-recovery PSA balance. The PSA comprises the following costs (PSA Costs):

- ERCOT Settlements – charges and credits from ERCOT, other than the Administrative and Nodal Fees.
- Fuel Costs – costs for fuel, fuel transportation, and hedging gains and losses.
- Net Purchased Power Costs – costs and offsetting revenues associated with short- and long-term purchased power agreements, and costs for distributed generation production.

As part of the City of Austin's annual budgeting process, which includes a public hearing, the PSA is determined by calculating the sum of all net power supply costs plus any existing over- or under-recovery of PSA Costs balance that are attributable to the PSA divided by projected service area sales during the historical twelve month period preceding the effective date of the PSA. This results in an annual uniform system rate per kWh, that is adjusted for voltage level to be applied to each of the customer classes. The PSA is adjusted by the following voltage level factors:

Voltage Level	Adjustment Factor
Secondary	1.0049
Primary	0.9821
Transmission	0.9696

The PSA may be adjusted to eliminate any over- or under-recovery as described below. Within 30 days of any adjustment of the PSA to eliminate over- or under-recovery of costs, the City Manager will publicly present a report to the City Council that provides the underlying calculations for the PSA both pre- and post-adjustment by system voltage level.

If, at any time, the balance of PSA costs recovered since the date of the last PSA adjustment is more than 110 percent of PSA costs actually incurred during such period, and such over-recovery is projected to remain above 110 percent after 12 months from the date of the last PSA adjustment, the PSA shall be adjusted to eliminate the over-recovery balance within the next 12 months.

If, at any time, the balance of PSA costs recovered since the date of the last PSA adjustment is less than 90 percent of PSA costs actually incurred, and such under-recovery is projected to remain less than 90 percent after 12 months from the date of the last PSA adjustment, the PSA may be adjusted to eliminate the under-recovery balance within the next 12 months.

At least once each year, the City Manager will publicly present a report to the City Council that provides the underlying calculations for the PSA by customer class. These calculations will break out fuel costs, ERCOT charges and credits, including ancillary service sales, and purchased power costs and revenues, including bilateral sales. They will also show the extent of over- or under-recovery of PSA costs for the previous twelve months.

The PSA is seasonally adjusted to reflect Austin Energy's summer peaking nature, ERCOT market constraint and stresses during summer months. The seasonal PSA Cost percentage that is derived from a 3 year average of PSA Cost (two years of historical and one year of current costs).

PSA Cost Periods	Seasonal Adjustment Factor
Summer	40.26%
Non-Summer	59.74%
Total	100.00%

The seasonal PSA charges by voltage level are:

Voltage Level	Adjustment Factor	Summer Power Supply Rate ($/kWh)	Non-Summer Power Supply Rate ($/kWh)
System Average	1.0000	$0.03133	$0.03110
Secondary	1.0049	$0.03148	$0.03124
Primary	0.9821	$0.03076	$0.03053
Transmission	0.9696	$0.03037	$0.03015

Community Benefit Charge

Application:
Applies to all electric service whose point of delivery is located within the limits of Austin Energy's service territory, unless otherwise stated.

Character of Service:
The Community Benefit Charge recovers certain costs incurred by the utility as a benefit to Austin Energy's service area customers and the greater community. This charge shall be determined through the City budget process and applied by system voltage level. The charge include three specific programs and services provided to customers.

1. Service Area Lighting (SAL) recovers the cost of street lighting (other than lighting maintained by Texas Dept. of Transportation) and the operation of traffic signals located inside the city limits of Austin. Customers whose point of delivery is located outside the city limits of Austin are not subject to the Service Area Lighting component of the Community Benefit Charge.

2. Energy Efficiency Services (EES) recovers the cost of energy efficiency rebates and related costs, solar rebates, and the Green Building program offered by Austin Energy throughout its service area.

3. The Customer Assistance Program (CAP) funds projects that help qualifying low-income and other disadvantaged residential customers through bill discounts, payment assistance (Plus 1), and free weatherization services. Funding for CAP is provided through the CAP component of the Community Benefit Charge and unexpended and re-appropriated funds. Information regarding CAP shall be made available quarterly, including the number of residential customers enrolled automatically and through self-enrollment, the total and average amount of benefits provided, and the number of residential customers referred to the low-income weatherization program. With Council approval, funds unspent at the end of a fiscal year shall be rolled over to the next fiscal year's budget for the CAP program.

Effective Date October 1, 2016	**Service Area Lighting**	**Energy Efficiency Services**	**Customer Assistance Program**
Secondary Voltage (Residential) ($/kWh)			
Inside City Limits	$0.00145	$0.00246	$0.00172
Outside City Limits	$0.00000	$0.00246	$0.00118
Secondary Voltage (Non-Residential) ($/kWh)			
Inside City Limits	$0.00145	$0.00246	$0.00065
Outside City Limits	$0.00000	$0.00246	$0.00065
Primary Voltage ($/kWh)			
Inside City Limits	$0.00141	$0.00240	$0.00065
Outside City Limits	$0.00000	$0.00240	$0.00065
Transmission Voltage ($/kWh)			
Inside City Limits	$0.00139	$0.00237	$0.00065
Outside City Limits	$0.00000	$0.00237	$0.00065
Transmission and Primary Voltage ≥ 20 MW @ 85% aLF ($/kWh)			
Inside City Limits	$0.00000	$0.00000	$0.00065

Outside City Limits	$0.00000	$0.00000	$0.00065

Regulatory Charges

Application:
Applies to all electric service whose point of delivery is located within the limits of Austin Energy's service territory, unless otherwise stated.

Character of Service:
The Regulatory Charge recovers the following costs, excluding any costs recovered through the closed Fuel Adjustment Clause: 1) ERCOT transmission service charges and credits; 2) NERC/TRE regulatory fees and penalties; 3) the ERCOT Nodal and Administrative Fees; and 4) other material regulatory fees or penalties specific to the electric industry. The Regulatory Charge is applied by system voltage level on either an energy or demand basis and may be adjusted to eliminate any over- or under-recovery on a system basis. Changes to the Regulatory Charge shall be determined after notice and public hearing as required by City code.

Voltage Level	**Regulatory (Energy)** ($/kWh)	**Regulatory (Demand)** ($/kW)
Secondary	$0.01188	$3.18
Primary	N/A	$3.11
HLF Primary	N/A	$3.90
Transmission	N/A	$3.07
HLF Transmission	N/A	$3.99

Standby Capacity

Application:
These rates apply to electric service for standby power provided by Austin Energy during a scheduled or unscheduled outage of customer's production facilities whose point of delivery is located within the limits of Austin Energy's service territory.

Character of Service:
Service is provided under this rate schedule pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes.

For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

The Standby Capacity will be equivalent to the maximum demand of the load to be served by Austin Energy during a scheduled or unscheduled outage of the customer's power production facilities or as stipulated in the contract between Austin Energy and the customer.

Customer will be assessed a monthly Minimum Bill equal to the Standby Capacity Rate times the Standby Capacity.

Voltage Level	**Monthly Standby Capacity Rate** ($/kW)
Primary	$2.80
Transmission	$2.60

Rider Rate Schedules

Application:
These rider rates apply to electric service whose point of delivery is located within the limits of Austin Energy's service territory.

Character of Service:
Service is provided under these rate schedules pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Non-Residential Distributed Generation from Renewable Sources (Rider)

Application:
This Rider is available to any non-residential customer who owns or hosts an on-site generating system powered by a renewable resource with a capacity of not more than 20 kW-ac that is interconnected with Austin Energy's electric system. Non-residential customers who own or host an on-site generating system powered by a renewable resource with a capacity of more than 20 kW-ac shall not be subject to this rider, and instead will be subject to the terms and conditions of the rate schedule under which the customer receives service, for all energy delivered by Austin Energy.

Renewable energy technologies include those that rely on energy derived directly from the sun, wind, geothermal, hydroelectric, wave, or tidal energy, or on biomass or biomass-based waste products, including landfill gas. A renewable energy technology does not rely on energy resources derived from fossil fuels, waste products from fossil fuels, or waste products from inorganic sources.

Terms and Conditions:
All charges, character of service, and terms and conditions of the rate schedule under which the customer receives service apply except as expressly altered by this rider. The customer shall comply with applicable Austin Energy interconnection requirements, including submittal of any required interconnection application and signed agreement. The customer is responsible for the costs of interconnecting with Austin Energy's electric system, including transformers, service lines, or other equipment determined necessary by Austin Energy for safe installation and operation of the customer's equipment. The customer is responsible for any costs associated with required inspections and permits.

Metering under this rider shall be by a single master meter capable of registering the flow of electricity in both directions to determine the customer's net energy flow. Other meters may be required to track renewable energy generation for regulatory compliance or incentive purposes, or as otherwise required by Austin Energy's Interconnection Guidelines and Design Criteria.

The customer's billed kilowatt-hour (kWh) shall be the customer's monthly net energy (kWh) use, which is the energy delivered by Austin Energy to the customer less any energy received from the customer's system to the Austin Energy distribution system during the billing month. If in any billing month the customer's monthly net energy use is negative, the customer's electric bill shall be credited as follows:

- If the Power Supply Adjustment applies, the monthly credit equals the monthly net energy times the Power Supply Adjustment (¢/kWh).

- If the GreenChoice® Energy (Rider) applies, the monthly credit equals the monthly net energy times the Power Supply Adjustment (¢/kWh).

Any charges not collected on a kWh basis are not altered by this calculation. Any credit shall be applied to the customer's bill for electric service. Any credit in excess of the customer's total charges for electric service, excluding the customer charge, shall be carried forward and applied to the customer's next electric bill.

GreenChoice® Energy (Rider)

Subscriptions under the GreenChoice® program support the City of Austin's inclusion of renewable fuel sources in its power generation portfolio. This energy cannot be directed to any one particular destination on the Electric Reliability Council of Texas electric grid, including participant's premises.

Application:
This rider applies to electric service to a customer subscribed to the City of Austin's GreenChoice® program.

Terms and Conditions:
Except for subscriptions of 1.2 million kilowatt-hours or more annually, subscriptions entered into after September 30, 2013, must be for 100 percent of a meter's monthly energy usage and will receive the adjustable GreenChoice® Charges. Non-residential customers may opt to enter into a written subscription contract for a one-year term after which the subscription will continue on a monthly basis. Customers not under contract may unsubscribe from the program at any time. A customer who unsubscribes may not re-subscribe until the following calendar year.

After September 30, 2014, a customer who subscribes a total annual amount of 1.2 million kilowatt-hours or more may receive the adjustable GreenChoice® Charges as provided below or may enter into a written subscription contract for a fixed GreenChoice® Charges until December 31, 2019. Each account subscribed to the program for the fixed charge must be subscribed for either: 1) 100 percent of the account's energy usage; or 2) a specified amount of energy usage of at least 100,000 kilowatt-hours per billing month.

Under subscriptions to Batches 5 or 6, the GreenChoice® Charges will be applied to 100 percent of the customer's energy usage, unless otherwise specified in a subscription contract in effect on September 30, 2013, through the Batch's end date. Batches 5 and 6 are closed to additional subscriptions. A non-residential account that has been subscribed to Batch 5 or 6 may not be re-subscribed under new terms before the subscription Batch's end date.

The terms of a subscription contract in effect on December 31, 2014, shall prevail in the event of a conflict with this rider. The director of Austin Energy shall develop the contract terms and conditions for subscriptions entered into after December 31, 2014.

Green Choice® Charges:
While subscribed to the GreenChoice® program, a customer will be billed Green Choice® Charge in lieu of the Power Supply Adjustment (PSA) that would otherwise apply to the customer's subscribed energy usage, unless otherwise noted in the appropriate rate schedule.

Subscription Type	**GreenChoice® Charges** ($/kWh)
Effective Dates before October 1, 2013	
Batch 5 (End Date December 31, 2022)	$0.055000
Batch 6.21 (End Date December 31, 2021)	$0.057000
Effective Date October 1, 2013	
Adjustable	PSA amount plus $0.01000
Fixed	$0.04900
Effective Date January 1, 2015	

Residential SmartCents	PSA amount plus $0.00750
Commercial BusinessCents	PSA amount plus $0.00750
Commercial Energizer	PSA amount plus $0.00750
Commercial Patron 14	$0.04900
Commercial Patron 15	$0.04400

Value-Of-Solar (Rider)

Application:
Applies to any Residential Service account that has an on-site solar photovoltaic system interconnected with Austin Energy's distribution system behind the master meter.

Terms and Conditions:
Billable kilowatt-hour shall be based on metered energy delivered by Austin Energy’s electric system and the metered energy consumed from an on-site solar system; also known as, the total metered energy consumption during the billing month. All non-kWh-based charges under the Residential Service rate schedule shall remain unaffected by the application of this rider.

For each billing month the customer shall receive a non-refundable, non-transferable credit equal to the metered kilowatt-hour output of the customer's photovoltaic system multiplied by the current Value-of-Solar Rate plus any carry-over credit from the previous billing month. Credits are applicable to the customer's total charges for Residential Service in the customer's name on the same premise and account where the on-site solar photovoltaic system is interconnected. Any remaining amount of credit(s) shall be carried forward and applied to the customer's next electric service bill. In the event of service termination, any credit balance will be applied to the Power Supply Adjustment (PSA) to reduce net purchased power costs.

The Value-of-Solar Rate is a tariff rider that is set annually through the Austin Energy budget approval process. Effective January 1 of each calendar year, the rate calculation uses the Value-of-Solar assessment’s monthly average of the prospective twelve-months and the shorter period of either: a) the prevailing assessments since October 1, 2012, or b) the previous 48 months.

Effective Dates	**Value-of-Solar Rates** ($/kWh)
October 1, 2012	$0.12800
January 1, 2014	$0.10700
January 1, 2015	$0.11300
January 1, 2016	$0.10900

Load Shifting Voltage Discount (Rider)

Application:
Applies to any non-residential customer who, at a minimum shifts 30 percent of the customer's normal annual monthly average on-peak billed demand using storage technologies (*e.g.*, thermal energy storage), whose point of delivery is located within the limits of Austin Energy's service territory. The normal on-peak billed demand is defined as the maximum-billed demand recorded prior to taking service on this discount rider rate schedule, and corresponding energy, during the last 12-month period, or as may be determined by Austin Energy.

Character of Service:
Service is provided under these rate schedules pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
The non-residential customer shall enter into a separate agreement with Austin Energy for this load shifting voltage discount rider rate schedule. The voltage discount rider rate schedule will be applied to the underlining rates within the standard rate schedules for which the customers load and voltage would qualify. Customer shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes.

The Billed kW used to determine the Electric Delivery, the Demand, and Regulatory Charges shall be based on the highest 15-minute metered demand recorded during the Load Shifting on-peak period and adjusted for power factor. The Energy Charge shall be based on all energy consumption during the Load Shifting on-peak period. All other Charges (*i.e.*, PSA, CBC, etc.) will be billed at the underlining rates schedules based on all consumption.

The load shifting on-peak period load shall be shifted, not eliminated, nor replaced by the use of alternative fuels. There are no load forgiveness for operations during on-peak periods. For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Load Shifting Periods

	Annual
On-Peak Hours	
3:30 P.M. – 6:30 P.M.	Everyday
Off-Peak Hours	
6:30 P.M. – 3:30 P.M.	Everyday

Service Area Program

Application:
This service area program rate schedule applies to electric service whose point of delivery is located within the limits of Austin Energy's service territory.

Character of Service:
Service is provided under this rate schedule pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

Electric Vehicle Public Charging

This rate schedule applies to electric service to a customer through a public electric vehicle charging station under the Electric Vehicle Public Charging.

Six-month Subscription	
Charging (unlimited)	$23.095
No Subscription	
Charging ($/hour)	$1.85

Residential Service Pilot Programs

Application:
These pilot programs' rate schedules apply to electric service for domestic purposes in each individual metered residence, apartment unit, mobile home, or other dwelling unit whose point of delivery is located within the limits of Austin Energy's service territory. The appropriate General Service schedules applies where a portion of the dwelling unit is used for either: a) conducting a business or other non-domestic purposes, unless such use qualifies as a home occupation pursuant to City Code Chapter 25-2-900; or b) for separately-metered uses at the same premises, including, but not limited to: water wells, gates, barns, garages, boat docks, pools, and lighting. These rates apply to secondary voltage less than 12,470 volts nominal line to line.

Each rate schedule will be limited to a participation of 100 individual meters on a first-come, first-served basis, unless stated otherwise on their applicable rate schedule. Austin Energy may administratively suspend availability of these pilot programs at any time or append full participation.

Character of Service:
Service is provided under these rate schedules pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required. In case of a conflict, the terms and conditions for each of the pilot programs as laid out in their appropriate rate schedules govern.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under these rate schedules shall remain unaffected by the application of a rider(s).

Pilot programs availability is contingent upon Austin Energy's operational feasibility, system configuration, availability of appropriate meters, and the customer's premise. Customers selecting these rate options are not eligible to participate in levelized billing. The rate tables below reflect rates with an effective date of October 1, 2016. For information on rates (*i.e.*, power supply adjustment, community benefit, and regulatory) prior to this effective date, please see corresponding schedules in the tariff (if applicable). For definition of charges listed below, see "Glossary of Terms" at the back of this tariff.

Customers are advised to conduct their own independent research before making any decisions because of the availability of these temporary pilot programs. If a customer elects to participation in any of the programs, the customer also agrees to participate in Austin Energy's load research efforts by allowing the customer's data to be collected. Austin Energy's use of such load research data will be strictly limited to the provision of electric service. Austin Energy will not disclose, share, rent, lease, or sell such data to any third party or affiliate for any other purpose, without the customer's express written consent.

Discounts:
Residential customers who receive, or who reside with a household member who receives, assistance from the Comprehensive Energy Assistance Program (CEAP), Travis County Hospital District Medical Assistance Program (MAP), Supplemental Security Income Program (SSI), Medicaid, Veterans Affairs Supportive Housing (VASH), the Supplemental Nutritional Assistance Program (SNAP), the Children's Health Insurance Program (CHIP), or the Telephone Lifeline Program are eligible for a discount under the

Customer Assistance Program (CAP). The priority for program funding is CEAP, MAP, SSI, Medicaid, VASH, and SNAP followed by CHIP and then Telephone Lifeline recipients. Eligible residential customers will be automatically enrolled in the discount program through a third-party matching process, with self-enrollment also available directly through Austin Energy.

Customers enrolled in the discount program are exempt from the monthly Customer Charge and the CAP component of the Community Benefit Charge and shall receive a 10 percent bill reduction on kilowatt-hour-based charges, unless stated otherwise on their applicable rate schedule. Customers in the discount program, as well as other low income and disadvantaged residential customers, may be eligible for bill payment assistance through Plus 1 and for free weatherization assistance.

Rider Schedules:
Services under these rate schedules are eligible for application of GreenChoice Energy (Rider) and Value-Of-Solar (Rider), unless stated otherwise on their applicable rate schedule.

Time-Of-Use Rates

In lieu of the Standard Rates under the Residential Service rate schedule, customers receiving service under this rate schedule may choose the following time-of-use charges to be applied for a term of no less than twelve (12) consecutive billing cycles, otherwise, an early termination fee of $250.00 will be applied; at Austin Energy’s sole discretion the fee could be waived.

Fuel Periods:

Weekdays	
Off-Peak	10:00 P.M. – 7:00 A.M.
Mid-Peak	7:00 A.M. – 3:00 P.M., 6:00 P.M. – 10:00 P.M.
On-Peak	3:00 P.M. – 6:00 P.M.
Weekends	
Off-Peak	Entire Day

Time-Of-Use Charges

		Summer (June through September)	**Non-Summer** (October through May)
Basic Charges ($/month)			
Customer		$10.00	$10.00
Delivery		$0.00	$0.00
Fuel Charges ($/kWh)			
Weekdays			
	Off-Peak	$0.02586	$0.02393
	Mid-Peak	$0.03078	$0.03097
	On-Peak	$0.11894	$0.03139
Weekends			
	Off-Peak	$0.02586	$0.02393

Energy Charges ($/kWh)		
0 – 500 kWh	$0.03300	$0.03300
501 – 1,000 kWh	$0.05600	$0.05600
1,001 – 1,500 kWh	$0.07595	$0.07595
1,501 – 2,500 kWh	$0.09100	$0.09100
Over 2,500 kWh	$0.10595	$0.10595
Community Benefit Charges ($/kWh)		
Energy Efficiency Services	$0.00246	$0.00246
Customer Assistance Program		
Inside City Limits	$0.00172	$0.00172
Outside City Limits	$0.00118	$0.00118
Service Area Lighting *(Only applies to Inside City Limits Accounts)*	$0.00145	$0.00145
Regulatory Charge ($/kWh)		
Regulatory	$0.01188	$0.01188

Prepayment Rates

In lieu of the Residential Standard Rates, the prepayment rate schedule is available on a voluntary basis to customers within Austin Energy service service territory who receive their electric service from Austin Energy but their water and wastewater service from a non-City of Austin provider. The prepayment pilot program is available for a term of no more than 9 consecutive billing cycles, with no term extending beyond September 30, 2016. Participation will be limited to 300 individual meters on a first-come, first-served basis. Participants in the program shall receive service pursuant to the terms set forth in this Prepayment Rates Schedule and City Code Chapter 15-9. In the event of a conflict between the Prepayment Rates Schedule and the City Code, the Prepayment Rate Schedule shall govern.

Terms and Conditions:
In order to enroll, the customer must establish a prepayment credit balance. Security deposits are not required. Deposits previously paid to Austin Energy shall be returned to the customer or may be applied to the prepayment balance at the customer's request. Outstanding balances must either be paid prior to enrollment or will be placed on a deferred payment plan with a fixed percentage of all future payments applied to the outstanding balance. Prepayment participants are not eligible for new payment arrangements or credit extensions.

Energy usage will be charged on a daily basis; Council approved customer charges, miscellaneous charges, taxes and fees will be prorated. Participants in the prepayment pilot program will receive a 'true-up' paper or electronic monthly bill. Account balances may be checked through the prepayment web portal 24 hours a day, 7 days a week.

Prepayment pilot customers will receive notifications and alerts about their account. Upon enrollment, the prepayment customer will determine by which method they will receive communications: text (which may incur phone carrier charges), email or phone call. The prepayment customer must select at least one Austin Energy-approved notification method. Austin Energy will not be responsible for any termination of service or other damages resulting from the account holder's failure to update alert settings and contact information.

The prepayment customer is responsible for maintaining a credit balance in order to maintain electric service. Austin Energy will notify program participants when the prepayment account balance is at or below a predetermined threshold. Austin Energy may disconnect a customer’s utility service without notice if the account reaches a zero or negative balance. Prepayment pilot program customers will no longer receive a written notice of disconnection. Service will be reconnected upon receipt of payment for the outstanding balance plus a payment amount to be credited towards future energy use. There are no disconnections during weather moratoriums; however, customers are liable for the payment of energy usage which occurs during this time.

Prepayment customers will have access to existing Austin Energy payment options. It is the customer’s responsibility to allow enough time for payment processing. Any charges incurred by Austin Energy as a result of insufficient fund checks/electronic fund transfers, returned credit card payments, and the like shall be applied immediately to the account balance and may result in the disconnection of service if the account balance becomes zero or negative. Austin Energy reserves the right to disconnect electric service immediately without prior notice for specific reasons per City Code Chapter 15-9, Article 7. Austin Energy will close any prepayment account that has a zero or negative balance for a period of thirty (30) days; any account disconnected for such reason must reestablish service pursuant to City Code Chapter 15-9.

Electric customers or members of the household who are dependent upon electrical devices for health-related reasons, including life-sustaining equipment, or have Lifeline status are ineligible to participate in the program. Customers who receive benefits from City of Austin Utilities’ Customer Assistance Program are ineligible for this rate schedule. Value-Of-Solar (Rider) is not applicable to this rate schedule.

Prepayment Daily Charges

	Inside City Limits	**Outside City Limits**
Basic Charges ($/day)		
Customer	$0.33	$0.33
Delivery	$0.00	$0.00
Energy Charges ($/kWh/day)		
0 – 16 kWh	$0.03300	$0.03800
16 – 33 kWh	$0.05600	$0.05600
33 – 49 kWh	$0.07595	$0.07815
49 – 82 kWh	$0.09100	$0.07815
Over 82 kWh	$0.10595	$0.07815
Power Supply Adjustment Charge ($/kWh)		
Summer Power Supply (June – Sept)	$0.03148	$0.03148
Non-Summer Power Supply (Oct – May)	$0.03124	$0.03124
Community Benefit Charges ($/kWh)		
Customer Assistance Program	$0.00172	$0.00118
Service Area Lighting	$0.00145	$0.00000
Energy Efficiency Services	$0.00246	$0.00246
Regulatory Charge ($/kWh)		
Regulatory	$0.01188	$0.01188

Plug-In Electric Vehicle Charging Rates

Application:

For a separate residential meter circuit (installed at the customer's expense) attached to an in-home electric vehicle level 1, or higher, charging station for charging a plug-in electric vehicle (PEV), which is connected to the same meter that registers usage of the customer's primary domestic residence. Customers receiving service under this rate schedule may choose the following electric vehicle charges to be applied for a term of no less than 12 consecutive billing cycles. If the customer elects to terminate participation in the program, the customer must pay an early termination fee of $200.00. Austin Energy may, in its sole discretion, elect to waive this termination fee. This rate schedule includes unlimited customer access to public electric vehicle charging station under the Electric Vehicle Public Charging rate schedule.

Terms and Conditions:

These charges are in addition to any other services the premise might be receiving; customers served under this rate schedule will be provided separate primary meter billing amounts and PEV meter billing amounts in their electric bill(s). The customer's primary metered usage is billed according to the primary rate schedule selected by the customer. The customer's PEV usage is billed according to this residential PEV schedule. The PEV meter billed amount will be based upon data delivered to Austin Energy.

In-home electric vehicle charging must be during off-peak periods, otherwise, all energy consumption will be multiplied by the fuel charges for their applicable periods; this applies when energy consumption outside of off-peak periods is greater than 10 percent of total monthly energy consumption. A one-time enrollment payment of $150 will be applied.

Customers receiving PEV charging station service are not eligible for any discounts and the Value-Of-Solar (Rider) rate schedule (if the customer has Value-Of-Solar it would be attached to the residential primary meter account, not the EV sub-meter account), under this rate schedule. Application of GreenChoice® Energy (Rider) will be applied to all energy consumption from the PEV meter.

Time Periods:

Weekdays	
Off-Peak	7:00 P.M. – 2:00 P.M.
On-Peak	2:00 P.M. – 7:00 P.M.
Weekends	
Off-Peak	Entire Day

PEV Charging Station Charges

	Summer (June through September)	**Non-Summer** (October through May)
Basic Charges ($/month)		
Delivery		
Demand (< 10 kW)	$30.00	$30.00
Demand (≥ 10 kW)	$50.00	$50.00
Fuel Charges ($/kWh) – Only applies if greater than 10 percent of total monthly energy consumption is used		

outside of “Off-Peak” periods, then these charges are applied to all energy consumption.			
Weekdays			
	Off-Peak	$0.00000	$0.00000
	On-Peak	$0.40000	$0.14000
Weekends			
	Off-Peak	$0.00000	$0.00000

Closed Rate Schedule

Application:
THIS RATE SCHEDULE IS CLOSED TO NEW CUSTOMERS. This rate schedule applies to electric service whose point of delivery is located within the limits of Austin Energy's service territory.

Character of Service:
Service is provided under this rate schedule pursuant to City Code Chapter 15-9 (*Utility Service Regulations*) and the City of Austin Utility Criteria Manual, as both may be amended from time to time, and such other rules and regulations as may be prescribed by the City of Austin. Electric service of one standard character will be delivered to one point of service on the customer's premises and measured through one meter unless, at Austin Energy's sole discretion, additional metering is required.

Terms and Conditions:
Customers shall permit Austin Energy to install all equipment necessary for metering and permit reasonable access to all electric service facilities installed by Austin Energy for inspection, maintenance, repair, removal, or data recording purposes. All non-kilowatt-hour charges under this schedule shall remain unaffected by the application of a rider(s).

Large Service Contract (Closed)

Application:
These rates are only available to the State of Texas and apply to a large service contract (LSC) customer that executed a separate contract for this service on or after October 9, 2006, in form and substance acceptable to Austin Energy, but before May 24, 2012. The contract requires the customer to remain a full requirements customer of Austin Energy through May 31, 2017, on which date the customer's contract and the terms of this rate schedule shall terminate. If Austin Energy subsequently adopts a rate schedule that provides more favorable rates, terms, or conditions than provided by this rates schedule and which describes a customer class for which the customer's large service contract accounts qualify, then the customer may terminate its contract and receive service pursuant to such subsequent rate schedule. Austin Energy enters and executes the contract and assumes its obligation in its proprietary capacity as the owner and operator of a utility enterprise increasingly in competition with other power suppliers for the attraction and retention of industrial loads, and in order to induce customer to remain a customer of Austin Energy. This rate schedule shall be effective through May 31, 2017, for all contracts between Austin Energy and the State of Texas.

Terms and Conditions:
Services under this rate schedule are eligible for application of Time-Of-Use Rates and Thermal Energy Storage (Rider) attached to them.

The LSC rates begins on the first day of the customer's billing cycle following the date that a separate contract has been executed between Austin Energy and the State of Texas, and shall be in effect for a period of thirty-six (36) months thereafter.

Not earlier than the first day of the thirty-seventh month after the effective date and not later than the last day of the seventy-second month after the effective date, a most favored nations clause applies (which clause does not apply to a rate paid by a governmental entity of the State of Texas, that is mandated by Federal or State law, the Public Utility Commission, a judicial body, or a retail pilot program affecting a customer of Austin Energy). It is the intent of this provision that the most favored nations clause will not apply unless Austin Energy voluntarily charges a lower rate to another LSC customer (who receives power at 12,500 volts or higher and has a demand for power that meets or exceeds 3,000 kW for any two months within the previous twelve months). If Austin Energy is required by Federal or State law, the Public Utility Commission, or a judicial body to charge a lower rate to a customer or group of customers, then the most favored nations clause does not apply.

For the remainder of the term of the contract after the seventy-second month after the effective date, Austin Energy may keep customer loads on-system by exercising a continuing right of first refusal to match the best offer of any competing suppliers. Austin Energy shall have until the later of sixty (60) months from the effective date, or seventy-five (75) days from the date it receives proper notice from Customer to exercise its right of first refusal. All such alternative proposals may be disclosed to Austin Energy on a confidential trade secret basis to the extent permitted by law, and shall be supported by a sworn affidavit signed by a corporate officer of the customer involved.

For the remainder of the term of the contract after the seventy-second month after the effective date, provided that retail competition in the electric utility industry in Texas is allowed and is available in Austin, Texas, Austin Energy shall not be obligated to charge the customer the service contract rates. In the event that retail competition is not allowed in Texas, or is not available in Austin, Texas, the customer shall continue to take power from Austin Energy at the LSC rates and be subject to extended application of the most favorable nations clause, until the end of the term of the contract.

These service contract rate schedules do not obligate Austin Energy to match the best offer of any competing supplier. In addition, nothing herein shall obligate Austin Energy to match any portion of an offer or other consideration not directly related to the supply of electric energy (i.e. generation, transmission and distribution) to the customer's facilities in the Austin area. In other words, Austin Energy would be required to match the total delivered cost of electric energy to the customer.

Contracts entered into under the provisions of these service contract rate schedules shall protect the integrity and enforceability of the City's right of first refusal. After a customer commences to purchase electric generation from a competing supplier (and Austin Energy fails to exercise its right of first refusal or to match the offer of a competing supplier), provision of generation service by Austin Energy to that portion of customer's total load removed from Austin Energy Electric System shall thereafter be at the sole option of Austin Energy. However, Austin Energy shall have a continuing obligation to provide transmission and distribution services, including ancillary services if needed, pursuant to its tariffs and the Public Utility Commission's Substantive Rules or other applicable laws and regulations.

A customer may not submit bids or offers received from competing suppliers, and thereby cause or require Austin Energy to exercise its right of first refusal in accordance with the terms of this tariff, more than once every twelve months.

Nothing in these service contract rate schedules or a contract under these service contract rate schedules shall operate to prevent, prohibit, or delay Austin Energy from recovering "stranded" costs from the customer, to the extent authorized by law, including those described in the Public Utility Regulatory Act.

If, notwithstanding the foregoing paragraph, any subsequent legislation would in any way operate to prevent, prohibit or delay recovery of the full amount, otherwise authorized by law, of "stranded" costs through any surcharge or additional charge or any new or revised rate level or element solely because of the existence or contents of these service contract rate schedules or the contract then the contract rates specified in these service contract rate schedules for energy, demand and fuel shall be deemed to be changed by an amount designed to exactly equal the revenue Austin Energy would otherwise recover but for the existence or contents of these service contract rate schedules or contract. Any such change shall take effect on the same date that the surcharge, additional charge or new or revised rate level or element would otherwise go into effect. If necessary the change may take the form of a one-time charge, assessable prior to or after customer switches generation suppliers. To the extent possible, while still allowing full recovery of the otherwise authorized amount, the change shall be incorporated into prospective monthly recurring charges.

The contract to be signed by customer shall explicitly incorporate the terms of the preceding two paragraphs, and also provide that the results contemplated by such paragraphs are essential and non-severable terms of the contract.

Notwithstanding any provision of these special contract rate schedules, neither customer nor Austin Energy shall be precluded from challenging the legal validity of any statute, regulations, or other provisions of law.

This rate schedule shall be extended to all of an LSC customer's accounts having a maximum demand of at least 500 kW.

Upon request, customers receiving service under these service contract rate schedules will be provided dual feed service with reserve capacity and maintenance under the 10 year long contract provisions of the Service Contract Rider, except that the customer will be responsible for the initial assessment fee, customer requested changes to the initial assessment, and facilities design and construction costs, as established in the fee schedule. Dual feed service with reserve capacity is electric service provided to the customer's premise(s) through two (or more) independent distribution feeders, with one feeder in normal service and the other in back-up service, capacity is reserved for the second feeder, and is placed into service upon an outage of the primary feeder.

If it is determined at any time by Austin Energy that the customer violated the provisions of these special contract rate schedules or the contract implementing the tariff, then the customer will be immediately billed on the LSC rate schedule, or as amended, from the date service was first commenced under these special contract rate schedules. The difference, plus interest at one percent (1%) per month, or the maximum allowable legal interest rate, whichever is less, from the date service was first commenced under these special contract rate schedules, shall immediately become due by customer to Austin Energy.

The contract executed under these special contract rate schedules shall address the rights of the City and the customer relating to the transfer or assignment of rights under these special contract rate schedules.

Definitions:

- Full Requirement Service – means generation, transmission, and distribution, (i.e., "bundled") service as presently supplied by City of Austin to customer, provided however, that the customer may self-generate up to 500 kW of its requirements from customer-owned, on-site renewable energy technology, subject to the terms and conditions of Austin Energy's Non-Residential Distributed Generation from Renewable Sources (Rider).

- Best Offer – means the cost of generation of a competing supplier, plus other costs, fees or expenses that a customer incurs in order to bring the generation to its point of service, including but not limited to: 1) transmission wheeling costs to Austin Energy Electric System; 2) transmission and distribution wheeling costs to the customer's point of service; and 3) costs to install or construct any on-site generation, interconnection or metering facilities.

- Competing Suppliers – includes, but is not limited to, a provider of generation services, energy services, and ancillary services, whether or not the supplier is located inside Austin Energy's current service territory, to the extent that the provider is permitted by law to serve the customer load.

- Billing Demand – the kilowatt demand during the fifteen-minute interval of greatest use during the current billing month as indicated or recorded by metering equipment installed by Austin Energy. When customer's power factor during the interval of greatest use is less than 85 percent, Billing Demand shall be determined by multiplying the indicated demand by 85 percent and dividing by the lower peak power factor; provided, however, the power factor adjustment specified in this paragraph shall be superseded by any subsequent rate schedule or ordinance governing power factor that may be enacted or amended by Austin Energy from time to time.

- Power Supply Adjustment (PSA) – plus an adjustment for variable costs, calculated according to the Power Supply Adjustment rate schedule, multiplied by the billable kWh.

Time-Of-Use Periods

	On-Peak Hours	**Off-Peak Hours**
Summer (May through October)		
Monday – Friday	*1:00 P.M. – 9:00 P.M.*	*9:00 P.M. – 1:00 P.M.*
Saturday, Sunday, and Holidays[1]	*None*	*12:00 A.M. – 12:00 A.M.*
Non-Summer (November through April)		
Monday – Friday	*800 A.M. – 10:00 P.M.*	*10:00 P.M. – 8:00 A.M.*
Saturday, Sunday, and Holidays[1]	*None*	*12:00 A.M. – 12:00 A.M.*

Monthly Charges:
Customer will be assessed a monthly minimum bill of $12.00, if the below calculation result in a charge of less than $12.00.

Standard Rates

	Summer (May through October)	**Non-Summer** (November through April)
Demand Charges ($/kW)		
All kWs	$12.54	$11.40
Energy Charges ($/kWh)		
All kWhs	$0.01110	$0.01110
Power Supply Adjustment ($/kWh)		
All kWhs	$0.03076	$0.03053

Time-Of-Use Rates

At the option of the customer, a separate agreement may be entered into between the City and the customer for a time-of-use incentive rate.

[1] U.S. National Holidays are Memorial Day, Independence Day, and Labor Day.

Billed demand will be based on the fifteen-minute interval of greatest use during an on-peak period for the current billing month. All other adjustments will be included as described above (See Definition: Billing Demand).

	Summer (May through October)	**Non-Summer** (November through April)
Demand Charges ($/kW)		
All kWs	$12.54	$11.40
Energy Charges ($/kWh)		
Off-Peak	$0.00560	($0.00290)
On-Peak	$0.02410	$0.01710
Power Supply Adjustment ($/kWh)		
All kWhs	$0.03076	$0.03053

Thermal Energy Storage (Rider)

Application:
This rate is applicable to any LSC customer who, through the use of Thermal Energy Storage technology, shifts to off-peak time periods no less than the lesser of 20 percent of the customer's normal on-peak Summer Billed Demand or 2,500 kW. The normal on-peak Summer Billed Demand shall be the maximum Summer Billed Demand recorded prior to attaching this rider, or as determined by Austin Energy.

Terms and Conditions:
At the option of the customer, a separate agreement may be entered into between the City and the customer for a Thermal Energy Storage (Rider) incentive rate. The on-peak load shall be shifted to off-peak, not eliminated, nor replaced by the use of alternative fuels. The customer shall continue to be billed under the time-of-use rates and in accordance with the following provisions:

- For Summer (May through October), the Summer Billed Demand shall be the highest fifteen-minute demand recorded during the on-peak period.
- For Non-Summer (November through April), the Non-Summer Billed Demand shall be the highest fifteen-minute demand recorded during the month, or 90 percent of the Summer Billed Demand set in the previous summer; whichever is less.

Time-Of-Use Periods

	Summer (May through October)	**Non-Summer** (November through April)
On-Peak Hours		
4:00 P.M. – 8:00 P.M.	Monday – Friday	None
Off-Peak Hours		
8:00 P.M. – 4:00 P.M.	Monday – Friday	Everyday
12:00 A.M. – 12:00 A.M.	Saturday, Sunday, and Holidays[2]	Everyday

[2] U.S. National Holidays are Memorial Day, Independence Day, and Labor Day.

Glossary of Terms

The purpose of this section is for customers to have a better understanding of the terminology used within the electric industry.

Adjustment Clauses

A provision in Austin Energy's tariff that provides for periodic changes in charges or credits to a customer due to increases or decreases in certain costs over or under those included in base rates.

Base Rate

That portion of the total electric rate covering the general costs of doing business, except for fuel, purchased power, and other pass-thru expenses.

Billed Demand

The demand upon which billing to a customer is based, as specified in a rate schedule or contract, metered X demand or billed demand may be the metered demand adjusted for power factor as specified in the rate schedule. It may also be based on the contract year, a contract minimum, or a previous maximum that does not necessarily coincide with the actual measured demand of the billing period.

Customer

A meter, individual, firm, organization, or other electric utility that purchases electric service at one location under one rate classification, contract, or schedule. If service is supplied to a customer at more than one location, each location shall be counted as a separate customer unless the consumptions are combined before the bill is calculated.

Customer Charge

Customer Charge is a monthly charge to help Austin Energy recover the customer-related fixed costs that reflect the minimum amount of equipment and services needed for customers to access the electric grid. Such costs are billing, metering, collections, customer service, service drops, cost of meters, meter maintenance, and other customer-related costs; these costs vary with the addition or subtraction of customers. These costs do not vary with usage; therefore, it is appropriate to recover these costs in the Customer Charge, rather than Energy Charges.

Customer Class

The grouping of customers into homogeneous classes. Typically, electric utility customers are classified on a broad category of customer service: residential, general service (commercial), large general service (industrial), lighting, or contract. Some electric systems have individual customers (large users) with unique electric-use characteristics, service requirements, or other factors that set them apart from other general customer classes and thus may require a separate class designation.

Delivery (Distribution) Charges

The charges on an electric customer's bill for the service of delivering or moving of electricity over the distribution system from the source of generation to the customer's premise; sometimes referred to as Electric Delivery.

Demand Charges

That portion of the charge for electric service based upon the electric capacity (kW or kVa) consumed and billed based on billing demand under an applicable rate schedule. The cost of providing electrical transmission and distribution equipment to accommodate the customer's largest electrical load during a given period of time.

Demand (kW)

The rate at which electricity is being used at any one given time. Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time. Demand is often measured in Kilowatts, while energy use is usually measured in Kilowatt-hours. The term "load" is considered synonymous with "demand."

Electric Meter

A device that measures the amount of electricity a customer uses.

Electric Rate

The price set for a specified amount of electricity in an electric rate schedule or sales contract.

Electric Reliability Council of Texas (ERCOT)

An independent system operator that schedules power for the region, which represents about 90 percent of the State of Texas's electric load.

Energy Charges

That portion of the charge for electric service based upon the electric energy consumed or billed. Electrical energy is usually measured in kilowatt-hours (kWh), while heat energy is usually measured in British thermal units (Btu).

Energy Efficiency Programs

Programs sponsored by utilities or others specifically designed to achieve energy efficiency improvements. Energy efficiency improvements reduce the energy used by specific end- use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Energy Efficiency Service Charge

Charge assessed to customers to offset the cost of energy efficiency program services offered by Austin Energy.

Fuel Adjustment (PSA)

A rate schedule that provides for an adjustment to the customer's bill for the cost of power supply.

Green Pricing (GreenChoice)

An optional Austin Energy service that allows customers an opportunity to support a greater level of Austin Energy's investment in and/or purchase of power from renewable energy technologies. Participating customers pay a premium on their electric bill to cover the incremental cost of the additional renewable energy.

Inverted Rate Design

A rate design for a customer class for which the unit charge for electricity increases as usage increases.

Kilowatt-hour (kWh)

The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour. One kilowatt-hour equals 1,000 watt-hours. The number of kWhs is used to determine the energy charges on your bill.

Load Factor

The ratio of the average load in kilowatts supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. Load factor, in percent, is derived by multiplying the kilowatt-hours in the period by 100 and dividing by the product of the maximum demand in kilowatts and the number of hours in the period.

Load Profile

Shows the quantity of energy used by a class of customers at specific time intervals over a 24-hour period.

Load Shifting

Involves shifting load from on-peak to mid- or off-peak periods. Popular applications include use of storage water heating, storage space heating, cool storage, and customer load shifts to take advantage of time-of-use or other special rates.

Megawatt (MW)

One megawatt equals one million watts or 1,000 kWhs.

Megawatt-hour (MWh)

One megawatt-hour equals one million watt-hours or 1,000 kWs.

Minimum Bill

A minimum charge to a customer during the applicable period of time, which is typically the customer charge. A provision in a rate schedule stating that a customer's bill cannot fall below a specified level. A minimum charge is similar to a customer charge because it is designed to recover fixed costs of services such as meter reading, billing and facilities maintenance. Although this charge does not generally recover the full cost of these services, it does give the customer a price signal that these costs do exist.

Off-Peak

Period of time when the need or demand for electricity on AE's system is low, such as late evenings, nights, weekends, and holidays.

On-Peak

Period of time when the need or demand for electricity on AE's system is high, normally during the late afternoons and early evening hours of the day from Monday through Friday, excluding holidays.

Peak Load Pricing

Pricing of electric service that reflects different prices for system peak periods or for hours of the day during which loads are normally high.

Peak Season Pricing

Pricing of electric service that reflects different prices for system peak seasonal periods.

Power Factor

The ratio of real power (kW) to apparent power (kVA) at any given point and time in an electrical circuit. Generally, it is expressed as a percentage ratio.

Power Factor Adjustment

A clause in a rate schedule that provides for an adjustment in the billing if the customer's power factor varies from a specified percentage or range of percentages.

Primary Voltage

The voltage of the circuit supplying power to a transformer is called the primary voltage, as opposed to the output voltage or load-supply voltage, which is called secondary voltage. In power supply practice the primary is almost always the high-voltage side and the secondary the low-voltage side of a transformer, except at generating stations.

Public Street and Highway Lighting

Electricity supplied and services rendered for the purpose of lighting streets, highways, parks, and for other public places; or for traffic or other signal system service for municipalities, or for other divisions or agencies of State or Federal governments.

Rate Schedule

A statement of the rates, charges, and terms and conditions governing the provision of electric service that has been accepted by a regulatory body with established oversight authority.

Rate Structure

The design and organization of billing charges to customers. A rate structure can comprise one or more of the rate schedules defined herein.

Seasonal Rates

Rate schedules that are structured for the different seasons of the year. The electric rate schedule usually takes into account demand based on weather and other factors.

Secondary Voltage

The output voltage or load-supply voltage of a transformer or substation. In power supply practice secondary voltage is generally the low-voltage side of a transformer, except at generating stations.

Single-Phase Service

Service where facility (e.g., house, office, warehouse) has two energized wires coming into it. Typically serves smaller needs of 120V/240V. Requires less and simpler equipment and infrastructure to support and tends to be less expensive to install and maintain.

Special Contract Rate Schedule

An electric rate schedule for an electric service agreement between Austin Energy and another party in addition to, or independent of, any standard rate schedule.

Standby Service

Service that is not normally used but that is available through a permanent connection in lieu of, or as a supplement to, the usual source of supply.

Tariff

A published collection of rate schedules, charges, terms of service, rules and conditions under which the Austin Energy provides electric service to the public.

<u>Thermal Energy Storage</u>

Is a technology that stocks thermal energy by heating or cooling a storage medium so that the stored energy can be used at a later time for heating and cooling applications and power generation.

<u>Three-Phase Service</u>

Electric energy that is transmitted by three or four wires to the customer. Relatively high voltage customers usually receive three-phase power.

<u>Time-of-Use (Time-of-Day) Rates</u>

A rate structure that prices electricity at different rates, reflecting the changes in the AE's costs of providing electricity at different times of the day. With time-of-use rates, higher prices are charged during the time when the electric system experiences its peak demand and marginal (incremental) costs are highest. Time-of-use rates better reflect the cost of providing service, sending more accurate price indicators to customers than non-time-of-use rates. Ultimately, these rates encourage efficient consumption, conservation and shifting of load to times of lower system demand.

<u>Value of Service</u>

A utility pricing concept in which the usefulness or necessity of a service to a customer group replaces or supplements cost factors as a major influence on the rates charged to the group. In ratemaking, this means that the price charged reflects the service's value to the customer rather than its cost to the producer. Value of service need not equal the cost of service; for example, Austin Energy's Value-of-Solar is such a product.

<u>Volt</u>

The unit of electromotive force or electric pressure analogous to water pressure in pounds per square inch. It is the electromotive force that, if steadily applied to a circuit having a resistance of one ohm, will produce a current of one ampere.

<u>Watt</u>

The electrical unit of real power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing due to an electrical pressure of one volt at unity power factor. One watt is equivalent to approximately 1/746 horsepower, or one joule per second.